Easergy MiCOM P34x & P391

(P342, P343, P344, P345 & P391)

Generator Protection Relay

P34x & P391/EN M/Nc7

Software Version	B2
Hardware Suffix	L (P342) M (P343/P344/P345) A (P391)
Issue Date	06/2017

Technical Manual

Schneider Electric

CONTENTS

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software version:	B2
Connection diagrams:	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)

SAFETY INFORMATION

CHAPTER SI

Date:	07/2016	
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:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 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) P44x (P442 & P444): 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2)	P54x (P543, P544, P545 & P546): 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) P547: 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P74x (P741, P742 & P743): 10P740xx (xx = 01 to 07) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)

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Notes:

1 INTRODUCTION

This document and the relevant equipment documentation provide full information on safe handling, installation, testing, commissioning and operation of this equipment. This document 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 document 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, you should be familiar with the contents of the Safety Information chapter/Safety Guide SFTY/5L M/L11 or later issue, the Technical Data chapter and the ratings on the equipment 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.

The manuals within the MiCOM P40 range include notices, which contain safety-related information. These are ranked in terms of their importance (from high to low) as follows:

DANGER	**THIS INDICATES AN IMMINENTLY HAZARDOUS SITUATION WHICH, IF NOT AVOIDED, WILL RESULT IN DEATH OR SERIOUS INJURY.**
WARNING	**This indicates an potentially hazardous situation which, if not avoided, can result in death or serious injury.**
Caution	**This indicates an potentially hazardous situation which, if not avoided, can result in minor or moderate injury.**
Important	**This indicates an potentially hazardous situation which, if not avoided, can result in equipment damage.**

Note	*This indicates an explanation or gives information which is useful to know, but which is not directly concerned with any of the above.*

These may appear with relevant Symbols (possibly electrical hazard, safety alert, disposal concern, etc) to denote the nature of the notice.

These notices appear at the relevant place in the remainder of this manual.

2 HEALTH AND SAFETY

The information in this part 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, testing, commissioning, operating or working on the equipment (and any system to which it may be connected) will be completely familiar with the contents of the Safety Information chapter and the Safety Guide. We also assume that everyone working with the equipment (and any connected systems) will have sufficient qualifications, knowledge and experience of electrical systems. We also assume that they will work with a complete understanding of the equipment they are working on <u>and</u> the health and safety issues of the location in which they are working. All people must be able to perform tasks in accordance with accepted safety engineering practices. They must also be suitably authorised to energize and de-energize equipment and to isolate, ground (earth) and label it. Given the risks of working on electrical systems and the environments in which they may be located, they must be trained in the care and use of safety apparatus in accordance with safety engineering practices; and they should be trained in emergency first aid procedures.

Receipt, Handling, Storage and Unpacking Relays

Although relays are of a robust construction, we recommend that you become familiar with the Installation chapter, as this describes important issues associated with receiving, handling, storage and unpacking relays.

Planning

We recommend that a detailed plan is developed before equipment is installed into a location, to make sure that all of 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. The plan also needs to be aware of the risk of falling devices; such as equipment being knocked over, units being accidentally dropped or protruding units being knocked out of rack-mounted cabinets. Safety shoes are recommended, as well as other protective clothing such as safety hats and gloves.

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 fixed 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 the use of temporary protective Earthing Clamps. 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 earthing can be accomplished by installing cables designed for that purpose or by the use of intrinsic earthing clamp equipment. Temporary protective earthing clamp 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. Replace all devices, doors and covers before turning on the power to any device.

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

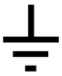
For safety reasons the following symbols and external labels, which may be used on the equipment or referred to in the equipment documentation, should be understood before the equipment is installed or commissioned.

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/5L 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) precations 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 mm^2 (3.3 mm^2 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. This includes humidity as well as temperature 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 Easergy Test Block, Easergy Test Plug and MiCOM P99x types, as hazardous voltages may be accessible when using these. CT shorting links must be in place before the insertion or removal of Easergy 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 use laser light. These laser-light sources should not be viewed directly, as they can cause permanent damage to eyesight. 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: 2006	This equipment requires a protective conductor (earth) connection to ensure user safety.

6.3 Installation Category

IEC 60255-27: 2013	Installation Category III (Overvoltage Category III)
EN 60255-27: 2014	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

INTRODUCTION

CHAPTER 1

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

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FIGURES

TABLES

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 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.	**Px4x/EN SI**
1	**Introduction** 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.	**P34x/EN IT**
2	**Technical Data** Technical data including setting ranges, accuracy limits, recommended operating conditions, ratings and performance data. Compliance with norms and international standards is quoted where appropriate.	**P34x/EN TD**
3	**Getting Started** 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.	**P34x/EN GS**
4	**Settings** List of all relay settings, including ranges, step sizes and defaults, together with a brief explanation of each setting.	**P34x/EN ST**
5	**Operation** A comprehensive and detailed functional description of all protection and non-protection functions.	**P34x/EN OP**
6	**Application Notes** 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.	**P34x/EN AP**
7	**Using the PSL Editor** This provides a short introduction to using the PSL Editor application.	**Px4x/EN SE**
8	**Programmable Logic** 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.	**P34x/EN PL**
9	**Measurements and Recording** Detailed description of the relays recording and measurements functions including the configuration of the event and disturbance recorder and measurement functions.	**P34x/EN MR**
10	**Product Design** 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.	**P34x/EN PD**
11	**Commissioning** Instructions on how to commission the relay, comprising checks on the calibration and functionality of the relay.	**P34x/EN CM**
12	**Test and Setting Records** This is a list of the tests made and the settings stored on the MiCOM IED.	**P34x/EN RC**

	Description	Chapter Code
13	**Maintenance**	**Px4x/EN MT**
	A general maintenance policy for the relay is outlined.	
14	**Troubleshooting**	**Px4x/EN TS**
	Advice on how to recognize failure modes and the recommended course of action. Includes guidance on whom within Schneider Electric to contact for advice.	
15	**SCADA Communications**	**P34x/EN SC**
	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.	
16	**Installation**	**Px4x/EN IN**
	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.	
17	**Connection Diagrams**	**P34x/EN CD**
	A list of connection diagrams, which show the relevant wiring details for this relay.	
18	**Cyber Security**	**Px4x/EN CS**
	An overview of cyber security protection (to secure communication and equipment within a substation environment). Relevant cyber security standards and implementation are described too.	
19	**Version History (of Firmware and Service Manual)**	**P34x/EN VH**
	This is a history of all hardware and software releases for this product.	
	Symbols and Glossary	**P34x/EN SG**
	List of common technical terms, abbreviations and symbols found in this documentation.	

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 P342/P343/P344/P345 generator protection relays have been designed for the protection of a wide range of generators.

- The P342 is suitable for protection of small to medium size generators (1-10 MVA) or can be used as back-up protection for larger generators.
- The P343 is suitable for protection of medium to large size generators (>10 MVA) or more important generators, providing generator differential, 100% stator earth fault via a 3rd harmonic measuring technique, pole slipping and unintentional energisation at standstill protection in addition to the features of the P342.
- The P344 is similar to the P343 but includes a second neutral voltage input for earth fault/interturn protection.
- The P345 is suitable for protection of large generators (>50 MVA) providing 100% stator earth fault protection via a low frequency injection technique in addition to the features of the P344.

The P343/P344/P345 also includes 10 function keys for integral scheme or operator control functionality and tri-color (red/yellow/green) LEDs. Rotor earth fault protection is provided by the P391 low frequency square wave injection, coupling and measurement unit connected to the rotor circuit. The measurement of the rotor resistance is passed to the P342/P343/P344/P345 via a current loop output (0-20 mA) on the P391 connected to one of the 4 current loop inputs on the P342/P343/P344/P345. The rotor ground fault protection is only available if the relay includes the CLIO hardware option.

3.1 Functional Overview

The P342/P343/P344/P345 generator protection relays contain a wide variety of protection functions. The protection features are summarized below:

Protection Functions Overview		P34x
87	Two types of differential protections are provided in P343/P344/P345, (1) generator differential protection and (2) generator - transformer protection. 1. Phase segregated generator differential protection is provided for high speed discriminative protection for all fault types. The differential protection can be selected as biased or high impedance or interturn. 2. Phase-segregated generator-transformer biased differential protection is provided for high-speed discriminative protection for all fault types. The differential protection includes ratio and vector compensation and 2nd/5th harmonic blocking for magnetizing inrush conditions.	P343 / P344 / P345
64	Restricted earth fault is configurable as a high impedance or a biased low impedance element. This can be used to provide high speed earth fault protection and is mainly applicable to small machines where differential protection is not possible or for transformer applications. The CT input is selectable as IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 via a setting.	P342 / P343 / P344 / P345
32R, 32L, 32O	Two definite time stages of power protection are provided and each stage can be independently configured to operate as Reverse Power (RP), OverPower (OP) or Low Forward Power (LFP) protection. The direction of the power measured by the protection can be reversed by selecting the operating mode, generating/motoring. The power protection can be used to provide simple back-up Overload Protection (OP), protection against motoring (RP, generating mode), CB interlocking to prevent overspeeding during machine shutdown (LFP, generating mode) and loss of load protection (LFP, motoring mode). The relays provide a standard 3-phase power protection element and also a phase-selective single-phase power protection element which can be used with a dedicated metering class CT using the sensitive current input.	P342 / P343 / P344 / P345
40	A two stage offset mho definite time impedance element is provided to detect failure of the machine excitation. A power factor alarm element is also available to offer more sensitive protection.	P342 / P343 / P344 / P345
46T	Negative phase sequence thermal overload protection is provided to protect against unbalanced loading which can cause overheating in the rotor. Both alarm and trip stages are provided.	P342 / P343 / P344 / P345

Protection Functions Overview		P34x
51V, 21	A voltage dependent overcurrent (controlled or restrained) or underimpedance protection is provided for back-up protection of phase faults. The voltage dependent overcurrent protection may be set as controlled or restrained with an Inverse Definite Minimum Time (IDMT) or Definite Time (DT). There are 2 stages of underimpedance protection which may be set as definite time only.	P342 / P343 / P344 / P345
50/51/67	Four overcurrent protection stages are provided which can be selected to be either non-directional, directional forward or directional reverse. Stages 1 and 2 may be set Inverse Definite Minimum Time (IDMT) or Definite Time (DT); stages 3 and 4 may be set DT only. The CT input is selectable as IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 via a setting.	P342 / P343 / P344 / P345
46OC/67NEG	Four definite time stages of negative phase sequence overcurrent protection are provided for remote back-up protection for both phase to earth and phase to phase faults. Each stage can be selected to be either non-directional, directional forward or directional reverse. The CT input is selectable as IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 via a setting.	P342 / P343 / P344 / P345
49G	Generator thermal overload protection based on I1 and I2 is provided to protect the stator/rotor against overloading due to balanced and unbalanced currents. Both alarm and trip stages are provided.	P342 / P343 / P344 / P345
49T	Transformer thermal overload protection is provided based on IEEE Std C57.91-1995. The thermal trip can be based on either hot spot or top oil temperature, each with three time-delayed stages available.	P342 / P343 / P344 / P345
50N/51N	Two stages of non-directional earth fault protection are provided for stator earth fault protection. Stage 1 may be set Inverse Definite Minimum Time (IDMT) or Definite Time (DT); stage 2 may be set DT only.	P342 / P343 / P344 / P345
64R	Rotor earth fault protection can be provided by a low frequency injection method. There are 2 stages of definite time under resistance protection. An external injection, coupling and measurement unit (P391) is required with this function. The measurement of the rotor resistance is passed to the P34x via a current loop output (0-20 mA) on the P391 connected to one of the 4 current loop inputs on the P34x. The rotor ground fault protection is only available if the relay includes the CLIO hardware option. The injection frequency is selectable 0.25/0.5/1 Hz via a jumper link in the P391	P342 / P343 / P344 / P345
67N/67W	One sensitive earth fault element is provided for discriminative earth fault protection of parallel generators. The protection can be selected to be either non-directional, directional forward or directional reverse. Either Zero sequence or negative sequence polarizing is available. 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.	P342 / P343 / P344 / P345
59N	Residual overvoltage protection is available for stator earth fault protection where there is an isolated or high impedance earth. The residual voltage can be measured from a broken delta VT, from the secondary winding of a distribution transformer earth at the generator neutral, or can be calculated from the three phase to neutral voltage measurements. Two independent stages of protection are provided for each measured neutral voltage input and also for the calculated value, each stage can be selected as either IDMT or DT. The P342/P343/P344/P345 have 2 measured and 2 calculated stages of residual overvoltage protection. The P344/P345 has an additional neutral voltage input and so has an additional 2 stages of measured residual overvoltage protection.	P342 / P343 / P344 / P345
27TN/59TN	A 3rd harmonic voltage element is provided to detect earth fault close to the generator star point. This element combined with the standard stator earth fault protection (59N/50N/51N) provides 100% stator earth fault protection. A definite time 3rd harmonic undervoltage element is provided if neutral voltage measurement is available at the neutral of the machine. This element is supervised by a 3-phase undervoltage element and optionally by 3-phase W/VA/VAr elements. A 3rd harmonic overvoltage element is provided if neutral voltage measurement is available from the terminals of the machine.	P343 / P344 / P345
64S	100% stator earth fault protection can also be provided by a low frequency injection method. There are 2 stages of definite time under resistance protection and 1 stage of definite time overcurrent protection. An external 20 Hz generator and bandpass filter is required with this function.	P345

Protection Functions Overview		P34x
24	A five-stage overfluxing (V/Hz) element is provided to protect the generator, or connected transformer, against overexcitation. The first stage is a definite time alarm, the second stage can be used to provide an inverse or definite time trip characteristic and stages 3/4/5 are definite time.	P342 / P343 / P344 / P345
81R	A 4-stage rate of change of frequency element (df/dt) is provided for Loss of Mains/Grid and load shedding applications.	P342 / P343 / P344 / P345
50/27	A voltage supervised overcurrent scheme is provided for dead machine/generator unintentional energisation at standstill (GUESS) protection to detect if the machine circuit breaker is closed accidentally, when the machine is not running. The CT input is selectable as IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 via a setting.	P343 / P344 / P345
27	A 2-stage undervoltage protection element, configurable as either phase to phase or phase to neutral measuring is provided to back up the automatic voltage regulator. Stage 1 may be selected as either IDMT or DT and stage 2 is DT only.	P342 / P343 / P344 / P345
59	A 2-stage overvoltage protection element, configurable as either phase to phase or phase to neutral measuring is provided to back up the automatic voltage regulator. Stage 1 may be selected as either IDMT or DT and stage 2 is DT only.	P342 / P343 / P344 / P345
47	A definite time negative phase sequence overvoltage protection element is provided for either a tripping or interlocking function upon detection of unbalanced supply voltages.	P342 / P343 / P344 / P345
81U/O	A 4-stage definite time underfrequency and 2-stage definite time overfrequency protection is provided for load shedding and back-up protection of the speed control governor.	P342 / P343 / P344 / P345
81AB	Turbine abnormal frequency protection is provided to protect the turbine blade from potential damage due to prolonged under/overfrequency operation of the generator. Up to six frequency bands can be programmed, each having an integrating timer to record the time spent within the band.	P342 / P343 / P344 / P345
RTD	10 RTDs (PT100) are provided to monitor the temperature accurately in the windings and bearings of the machine. Each RTD has an instantaneous alarm and definite time trip stage.	Option P342 / P343 / P344 / P345
50BF	A 2-stage circuit breaker failure function is provided with a 3 pole initiation input from external protection.	P342 / P343 / P344 / P345
37P/37N	Phase, neutral and sensitive earth fault undercurrent elements are available for use with for example the circuit breaker fail function.	P342 / P343 / P344 / P345
78	A lens shaped impedance characteristic is used to detect loss of synchronization (pole slipping) between the generation and the power system. Two zones are created by a reactance line which is used to distinguish whether the impedance centre of the pole slip is located in the power system or in the generator. Separate counters are used to count pole slips in the 2 zones. A setting is also provided to determine whether the protection operates in a generating mode, motoring mode or both.	P343 / P344 / P345
BOL	Blocked Overcurrent Logic (BOL) 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.	P342 / P343 / P344 / P345
VTS	Voltage transformer supervision is provided (1, 2 & 3 phase fuse failure detection) to prevent mal-operation of voltage dependent protection elements upon loss of a VT input signal.	P342 / P343 / P344 / P345
CTS	Current transformer supervision to prevent mal-operation of current dependent protection elements upon loss of a CT input signal.	P342 / P343 / P344 / P345
CLIO	4 analog (or current loop) inputs are provided for transducers (vibration, tachometers etc.). Each input has a definite time trip and alarm stage. Each input can be independently selected as 0-1/0-10/0-20/4-20 mA. 4 analogue (or current loop) outputs are provided for the analogue measurements in the relay. Each output can be independently selected as 0-1/0-10/0-20/4-20 mA.	Option P342 / P343 / P344 / P345

Protection Functions Overview		P34x
25	Check synchronizing (2-stage) with advanced system split features and breaker closing compensation time is provided. The P345 includes a dedicated voltage input for check synchronizing. For the P344 the VN2 input can be used for neutral voltage protection or check synchronizing. For the P342/P343 the VN1 input can be used for neutral voltage protection or check synchronizing.	P342 / P343 / P344 / P345
	Phase rotation - the rotation of the phases ABC or ACB for all 3-phase current and voltage channels can be selected. Also, for pumped storage applications where 2 phases are swapped the swapping of 2 phases can be emulated independently for the 3-phase voltage and 3-phase current channels.	P342 / P343 / P344 / P345
	Programmable function keys	10 (P343 / P344 / P345)
	Programmable LEDs (tri-color P343/P344/P345, red P342)	18 (P343 / P344 / P345) 8 (P342)
	Digital inputs (order option)	8 to 32
	Output relays (order option)	7 to 32
	Front communication port (EIA(RS)232)	P342 / P343 / P344 / P345
	Rear communication port (K-Bus/EIA(RS)485). The following communications protocols are supported: Courier, MODBUS, IEC870-5-103 (VDEW), DNP3.0.	P342 / P343 / P344 / P345
	Rear communication port (Fibre Optic). The following communications protocols are supported; Courier, MODBUS, IEC870-5-103 (VDEW) and DNP3.0.	Option P342 / P343 / P344 / P345
	Second rear communication port (EIA(RS)232/EIA(RS)485). Courier protocol.	Option P342 / P343 / P344 / P345
	Rear IEC 61850 Ethernet communication port.	Option P342 / P343 / P344 / P345
	Rear Redundant IEC 61850 Ethernet communication port	Option P342 / P343 / P344 / P345
	Time synchronization port (IRIG-B modulated/un-modulated).	Option P342 / P343 / P344 / P345

Table 1 - Functional overview

The relay supports these relay management functions as well as the ones shown above.

- Measurement of all instantaneous & integrated values
- Circuit breaker, status & condition monitoring
- Programmable Scheme Logic (PSL)
- Trip circuit and coil supervision (using PSL)
- Alternative setting groups (model dependent)
- Programmable function keys (model dependent)
- Control inputs
- Programmable allocation of digital inputs and outputs
- Sequence of event recording
- Comprehensive disturbance recording (waveform capture)
- Fault recording
- Fully customizable menu texts
- Power-up diagnostics and continuous self-monitoring of relay
- Commissioning test facilities
- Real time clock/time synchronization - time synchronization possible from IRIG-B input, opto input or communications
- Simple password management:
  CSL0 - No Security Administration Tool (SAT) required
- Advanced Cyber Security:
  CSL1 - Security Administration Tool (SAT) required
- Read only mode

3.2 Application Overview

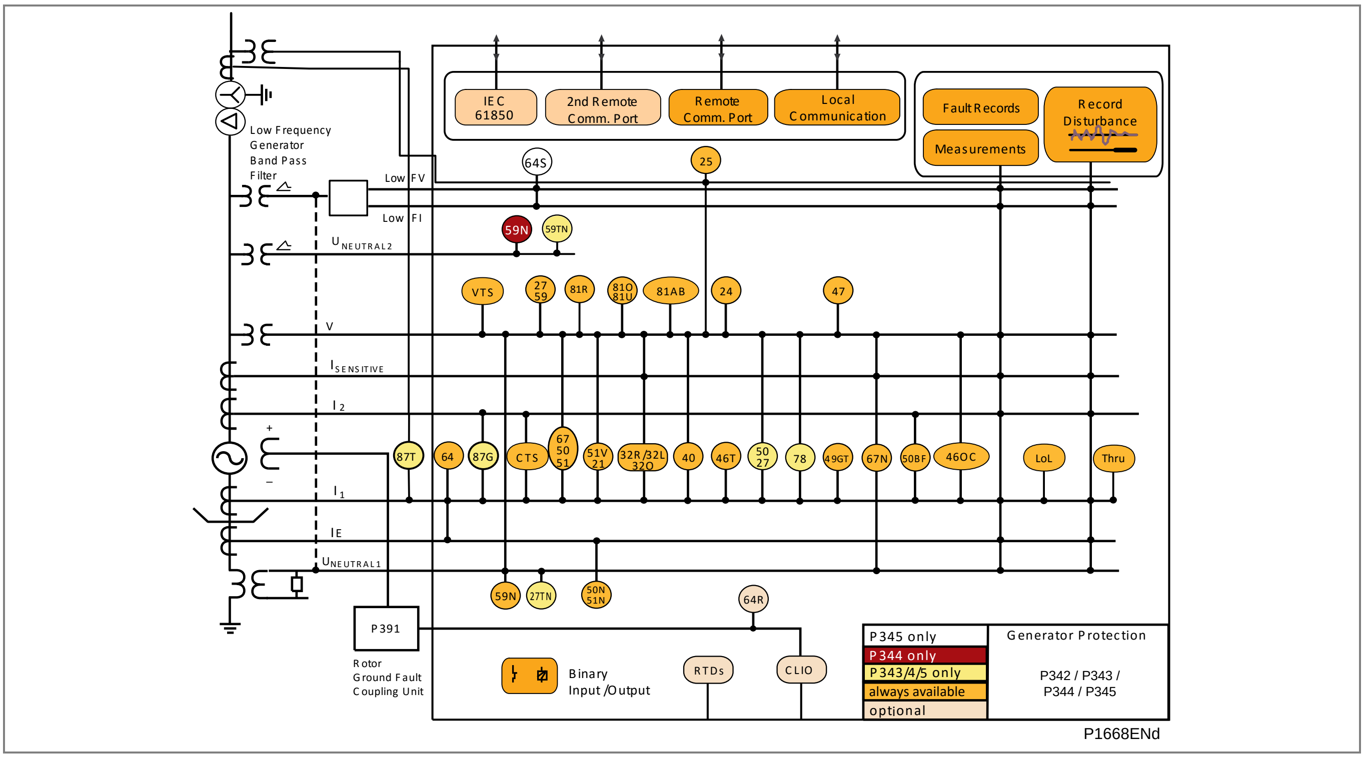

Figure 1 - Functional diagram

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

3.3 Ordering Options

The following information is required with an equipment order:

- MiCOM P342 Ordering Options
- MiCOM P343 Ordering Options
- MiCOM P344 Ordering Options
- MiCOM P345 Ordering Options
- MiCOM P391 Ordering Options

Note	*The Cortec table(s) list the options available as of the date of this documentation. The most up-to-date versions of these tables can be found on our web site (www.schneider-electric.com). It may not be possible to select ALL of the options shown here within a single item of equipment.*

3.3.1 MiCOM P342 Ordering Options

P342 Generator Protection Relay		P342						M				
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				2								
Hardware Options:	Protocol Compatibility											
Standard - None	1,2,3,4				1							
IRIG-B Only	1,2,3,4				2							
Fibre Optic Converter Only	1,2,3,4				3							
IRIG-B & Fibre Optic Converter	1,2,3,4				4							
2nd Rear Comms	1,2,3,4				7							
IRIG-B & 2nd Rear Comms	1,2,3,4				8							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 2 LC ports + 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				Q							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 3 RJ45 ports + Modulated/Un-modulated IRIG-B	6,B,G,L				R							
Ethernet (100Mbit/s), 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				S							
Product Specific Option:												
40TE Case, 8 Opto Inputs + 7 Relay Outputs						A						
40TE Case, 8 Opto Inputs + 7 Relay Outputs + RTD						B						
40TE Case, 8 Opto Inputs + 7 Relay Outputs + CLIO						C						
40TE Case, 16 Opto Inputs + 7 Relay Outputs						D						
40TE Case, 8 Opto Inputs + 15 Relay Outputs						E						
40TE Case, 12 Opto Inputs + 11 Relay Outputs						F						
60TE Case, 16 Opto Inputs + 16 Relay Outputs						G						
60TE Case, 16 Opto Inputs + 16 Relay Outputs + RTD						H						
60TE Case, 16 Opto Inputs + 16 Relay Outputs + CLIO						J						
60TE Case, 24 Opto Inputs + 16 Relay Outputs						K						
60TE Case, 16 Opto Inputs + 24 Relay Outputs						L						
60TE Case, 16 Opto Inputs + 16 Relay Outputs + RTD + CLIO						M						
60TE Case, 24 Opto Inputs + 16 Relay Outputs + RTD						N						
60TE Case, 16 Opto Inputs + 24 Relay Outputs + RTD						P						
40TE Case, 8 Opto Inputs + 11 Relay Outputs (Including 4 High Break)						Q						
60TE Case, 16 Opto Inputs + 20 Relay Outputs (Including 4 High Break)						R						
60TE Case, 16 Opto Inputs + 12 Relay Outputs (Including 4 High Break) + RTD						S						
60TE Case, 16 Opto Inputs + 12 Relay Outputs (Including 4 High Break) + CLIO						T						
60TE Case, 16 Opto Inputs + 12 Relay Outputs (Including 4 High Break) + RTD + CLIO						U						
Protocol / Communications Options:	Hardware Compatibility											
K-Bus	1,2,3,4,7,8						1					
Modbus	1,2,3,4,7,8						2					
IEC 60870-5-103 (VDEW)	1,2,3,4,7,8						3					
DNP3.0	1,2,3,4,7,8						4					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with simple password management - CSL0	Q,R,S						6					

P342 Generator Protection Relay		P342						M				
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with simple password management - CSL0	Q,R,S						B					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						G					
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						L					
Mounting Option:												
Flush Panel Mounting								M				
Order FX0021001 if rack mounting is required												
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:										B2		
Customisation:												
Default											8	
Customer											9	
Design Suffix:												
Phase 3 CPU												L

3.3.2 MiCOM P343 Ordering Options

P343 Generator Protection Relay with Differential		P343						M	0	0		
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				2								
Hardware Options:	Protocol Compatibility											
Standard - None	1,2,3,4				1							
IRIG-B Only	1,2,3,4				2							
Fibre Optic Converter Only	1,2,3,4				3							
IRIG-B & Fibre Optic Converter	1,2,3,4				4							
2nd Rear Comms	1,2,3,4				7							
IRIG-B & 2nd Rear Comms	1,2,3,4				8							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 2 LC ports + 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				Q							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 3 RJ45 ports + Modulated/Un-modulated IRIG-B	6,B,G,L				R							
Ethernet (100Mbit/s), 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				S							
Product Specific Option:												
Size 60TE Case, No Option (16 Optos + 14 Relays)						A						
Size 60TE Case, 16 Optos + 14 Relays + RTD						B						
Size 60TE Case, 16 Optos + 14 Relays + CLIO						C						
Size 60TE Case, 24 Optos + 14 Relays						D						
Size 60TE Case, 16 Optos + 22 Relays						E						
Size 80TE Case, 24 Optos + 24 Relays						F						
Size 80TE Case, 24 Optos + 24 Relays + RTD						G						
Size 80TE Case, 24 Optos + 24 Relays + CLIO						H						
Size 80TE Case, 32 Optos + 24 Relays						J						
Size 80TE Case, 24 Optos + 32 Relays						K						
Size 80TE Case, 24 Optos + 24 Relays + RTD + CLIO						L						
Size 80TE Case, 32 Optos + 24 Relays + RTD						M						
Size 80TE Case, 24 Optos + 32 Relays + RTD						N						
Size 80TE Case, 32 Optos + 16 Relays + RTD + CLIO						P						
Size 80TE Case, 16 Optos + 32 Relays + RTD + CLIO						Q						
Size 60TE Case, 16 Optos + 18 Relays (4 High Break)						R						
Size 60TE Case, 16 Optos + 11 Relays (4 High Break)						S						
Size 60TE Case, 16 Optos + 11 Relays (4 High Break) + CLIO						T						
Size 80TE Case, 16 Optos + 24 Relays (8 High Break)						U						
Size 80TE Case, 16 Optos + 24 Relays (8 High Break) + RTD						V						
Size 80TE Case, 16 Optos + 24 Relays (8 High Break) + CLIO						W						
Size 80TE Case, 16 Optos + 24 Relays (8 High Break) + RTD + CLIO						X						
Protocol / Communications Options:	Hardware Compatibility											
K-Bus	1,2,3,4,7,8						1					
Modbus	1,2,3,4,7,8						2					
IEC 60870-5-103 (VDEW)	1,2,3,4,7,8						3					

P343 Generator Protection Relay with Differential		P343						M	0	0		
DNP3.0	1,2,3,4,7,8						4					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with simple password management - CSL0	Q,R,S						6					
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with simple password management - CSL0	Q,R,S						B					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						G					
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						L					
Mounting Option:												
Flush Panel Mounting								M				
Rack Panel Mounting, (Size 80TE Case 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:										B2		
Customisation:												
Default											8	
Customer											9	
Design Suffix:												
Extended Phase 3 CPU												M

3.3.3 MiCOM P344 Ordering Options

P344 Generator Protection Relay with Differential & NVD Interturn		P344										
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				2								
Hardware Options:	Protocol Compatibility											
Standard - None	1,2,3,4				1							
IRIG-B Only	1,2,3,4				2							
Fibre Optic Converter Only	1,2,3,4				3							
IRIG-B & Fibre Optic Converter	1,2,3,4				4							
2nd Rear Comms	1,2,3,4				7							
IRIG-B & 2nd Rear Comms	1,2,3,4				8							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 2 LC ports + 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				Q							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 3 RJ45 ports + Modulated/Un-modulated IRIG-B	6,B,G,L				R							
Ethernet (100Mbit/s), 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				S							
Product Specific Option:												
Size 16 Case, No Option (24 Optos + 24 Relays)						A						
Size 16 Case, 24 Optos + 24 Relays + RTD						B						
Size 16 Case, 24 Optos + 24 Relays + CLIO						C						
Size 16 Case, 32 Optos + 24 Relays						D						
Size 16 Case, 24 Optos + 32 Relays						E						
Size 16 Case, 24 Optos + 24 Relays + RTD + CLIO						F						
Size 16 Case, 32 Optos + 24 Relays + RTD						G						
Size 16 Case, 24 Optos + 32 Relays + RTD						H						
Size 16 Case, 32 Optos + 16 Relays + RTD + CLIO						J						
Size 16 Case, 16 Optos + 32 Relays + RTD + CLIO						K						
Size 16 Case, 24 Optos + 20 Relays (4 High Break)						L						
Size 16 Case, 24 Optos + 20 Relays (4 High Break) + RTD						M						
Size 16 Case, 24 Optos + 20 Relays (4 High Break) + CLIO						N						
Size 16 Case, 24 Optos + 20 Relays (4 High Break) + RTD + CLIO						P						
Size 16 Case, 16 Optos + 24 Relays (8 High Break)						Q						
Size 16 Case, 16 Optos + 24 Relays (8 High Break) + RTD						R						
Size 16 Case, 16 Optos + 24 Relays (8 High Break) + CLIO						S						
Size 16 Case, 16 Optos + 24 Relays (8 High Break) + RTD + CLIO						T						
Protocol / Communications Options	Hardware Compatibility											
K-Bus	1,2,3,4,7,8						1					
Modbus	1,2,3,4,7,8						2					
IEC 60870-5-103 (VDEW)	1,2,3,4,7,8						3					
DNP3.0	1,2,3,4,7,8						4					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with simple password management - CSL0	Q,R,S						6					

P344 Generator Protection Relay with Differential & NVD Interturn		P344										
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with simple password management - CSL0	Q,R,S						B					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						G					
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						L					
Mounting Option												
Flush Panel Mounting								M				
Rack Panel Mounting								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										B2		
Customisation												
Default											8	
Customer											9	
Design Suffix:												
Extended Phase 3 CPU												M

3.3.4 MiCOM P345 Ordering Options

P345 Generator Protection Relay		P345										K
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				2								
Hardware Options	Protocol Compatibility											
Standard - Nothing	1,2,3,4				1							
IRIG-B Only	1,2,3,4				2							
Fibre Optic Converter Only	1,2,3,4				3							
IRIG-B & Fibre Optic Converter	1,2,3,4				4							
2nd Rear Comms port	1,2,3,4				7							
2nd Rear Comms port + IRIG-B	1,2,3,4				8							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 2 LC ports + 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				Q							
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 3 RJ45 ports + Modulated/Un-modulated IRIG-B	6,B,G,L				R							
Ethernet (100Mbit/s), 1 RJ45 port + Modulated/Un-modulated IRIG-B	6,B,G,L				S							
Product Specific Option												
Size 16 Case, No Option (24 Opto Inputs + 24 Relay Outputs)						A						
Size 16 Case, 24 Opto Inputs + 24 Relay Outputs + RTD						B						
Size 16 Case, 24 Opto Inputs + 24 Relay Outputs + CLIO						C						
Size 16 Case, 32 Opto Inputs + 24 Relay Outputs						D						
Size 16 Case, 24 Opto Inputs + 32 Relay Outputs						E						
Size 16 Case, 24 Opto Inputs + 24 Relay Outputs + RTD + CLIO						F						
Size 16 Case, 32 Opto Inputs + 24 Relay Outputs + RTD						G						
Size 16 Case, 24 Opto Inputs + 32 Relay Outputs + RTD						H						
Size 16 Case, 32 Opto Inputs + 16 Relay Outputs + RTD + CLIO						J						
Size 16 Case, 16 Opto Inputs + 32 Relay Outputs + RTD + CLIO						K						
Size 16 Case, 24 Opto Inputs + 16 Relay Outputs + 4 High Break Outputs						L						
Size 16 Case, 24 Opto Inputs + 16 Relay Outputs + 4 High Break Outputs + RTD						M						
Size 16 Case, 24 Opto Inputs + 16 Relay Outputs + 4 High Break Outputs + CLIO						N						
Size 16 Case, 24 Opto Inputs + 16 Relay Outputs + 4 High Break Outputs + RTD + CLIO						P						
Size 16 Case, 16 Opto Inputs + 16 Relay Outputs + 8 High Break Outputs						Q						
Size 16 Case, 16 Opto Inputs + 16 Relay Outputs + 8 High Break Outputs + RTD						R						
Size 16 Case, 16 Opto Inputs + 16 Relay Outputs + 8 High Break Outputs + CLIO						S						
Size 16 Case, 16 Opto Inputs + 16 Relay Outputs + 8 High Break Outputs + RTD + CLIO						T						
Protocol / Communications Options	Hardware Compatibility											
K-Bus	1,2,3,4,7,8,C						1					
Modbus	1,2,3,4,7,8,C						2					
IEC 60870-5-103 (VDEW)	1,2,3,4,7,8,C						3					
DNP3.0	1,2,3,4,7,8,C						4					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with simple password management - CSL0	Q,R,S						6					

P345 Generator Protection Relay		P345										K
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with simple password management - CSL0	Q,R,S						B					
IEC61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						G					
IEC61850 Edition 1 / 2 and DNP3 over Ethernet and DNP3.0 via rear RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) Required	Q,R,S						L					
Mounting Option												
Flush Mounting								M				
Rack Mounting								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												
Customisation												
Default												
Customer												
Design Suffix												
Extended Phase 3 CPU												M
SEPARATELY ORDERED Accessories - See Cortec worksheet with "Accessories" tab												
20 Hz Generator	PCS Material/ Ordering code											
Bandpass Filter	PCS Material/ Ordering code											
400/5A Tripping CT	PCS Material/ Ordering code											
Generator and Filter mounting	PCS Material/ Ordering code replace "*" in PCS Material/Ordering code for Generator & Filter by "S", "F" or "R"	S										
	replace "*" in PCS Material/Ordering code for Generator & Filter by "S", "F" or "R"	F										
	replace "*" in PCS Material/Ordering code for Generator & Filter by "S", "F" or "R"	R										

3.3.5 MiCOM P391 Ordering Options

P391(Generator Rotor Earth Fault Module)		**P391**	**9**	**1**		**00**	**A**	
Vx Auxiliary Rating:								
60 - 250 Vdc, 100 - 230 Vac			9					
Hardware Options:								
None				1				
Mounting Options:								
Rack Mounting					R			
Wall Mounting - not available					*			
Panel Mounting - not available					*			
Software Issue:								
Not applicable						00		
Design Suffix:								
Original hardware							A	

TECHNICAL DATA

CHAPTER 2

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

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TABLES

FIGURES

Notes:

1 MECHANICAL SPECIFICATIONS

1.1 Design

Modular Px40 platform relay:

- P342 in 40TE or 60TE case,
- P343 in 60TE or 80TE case
- P344/P345 in 80TE case.

Mounting is front of panel flush mounting, or 19” rack mounted (ordering options).

1.2 Enclosure Protection

Per IEC 60529:

- 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

Product	Case	Weight
P342	(40TE):	7.9kg
P342	(60TE):	9.2kg
P343	(60TE):	11.5kg
P343/P344/P345	(80TE):	14kg

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 and COM1 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 (RP1)

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 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).

2.8 Optional Second Rear Communications Port (RP2)

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.

2.9 Optional Rear IRIG-B Interface Modulated or Unmodulated

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

2.10 Optional Rear Ethernet Connection for IEC 61850

2.10.1 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

2.10.2 100BaseFX 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: LC Connector Optical Interface

2.11 Optional Rear Redundant Ethernet Connection for IEC 61850

2.11.1 100BaseFX 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: LC Connector Optical Interface

2.11.2 Transmitter Optical Characteristics 100 Base FX Interface

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 NA – Numerical Aperture					

Table 1 - Interface Transmitter optical characteristics 100 base FX interface

2.11.3 Receiver Optical Characteristics 100 base FX interface

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.

Table 2 - Receiver optical characteristics 100 base FX interface

3 RATINGS

3.1 AC Measuring Inputs

Nominal frequency: 50 and 60 Hz (settable)
Operating range: 45 to 70Hz

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:	<0.04 VA at In, <40 mOhms (0-30 In)In = 1A <0.45 VA at In, < 8 mOhms (0-30 In)In = 5A	
Thermal withstand:	continuous 4 In	for 10 s: 30 In for 1 s; 100 In

Standard linear to 16 In (non-offset AC current).
Sensitive linear to 2 In (non-offset AC current).

3.3 AC Voltage

Nominal voltage (Vn)	100 to 120 V or 380 to 480 V phase-phase
Nominal burden per phase	< 0.02 VA at 110/√3 V or 440/√3 V
Thermal withstand	continuous 2 Vn for 10 s 2.6 Vn
Linear to	200 V (100 V/120 V), 800 V (380/480 V).

4 POWER SUPPLY

4.1 Auxiliary Voltage (Vx)

Three ordering options:
(i) Vx: 24 to 32 Vdc
(ii) Vx: 48 to 110 Vdc,
(iii) Vx: 110 to 250 Vdc, and 100 to 240 Vac (rms).

4.2 Operating Range

(i) 19 to 38Vdc (dc only for this variant)

(ii) 37 to 150V (dc only for this variant)

(iii) 87 to 300V (dc), 80 to 265 V (ac).

With a tolerable ac ripple of up to 15% for a dc supply, per EN / IEC 60255-11, EN / IEC 60255-26.

4.3 Nominal Burden

Quiescent burden: 11W or 24 VA. (Extra 1.25 W when fitted with second rear communications board).

Additions for energized binary inputs/outputs:

For each opto input:

0.09 W (24 to 54 V)

0.12 W (110/125 V)

0.19 W (220/250 V)

For each energized output relay: 0.13W

4.4 Power-up Time

Time to power up < 11 s.

4.5 Power Supply Interruption

Per IEC 60255-11, EN / IEC 60255-26

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

Per IEC 61000-4-11, EN / IEC 60255-26

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
The operating range shall be 40 V to 60 V with an alarm raised at <35 V

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:
<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 250 A for 30 ms
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

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

Table 3 - Typical repetitive shots

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 60068-2-78: 2001:

56 days at 93% relative humidity and +40°C

Per IEC 60068-2-30: 2005:

Damp heat cyclic, six (12 + 12) hour cycles, 93% RH, +25 to +55°C

6.3 Corrosive Environments (for relays with harsh environment coating of PCBs)

Per IEC 60068-2-60: 1995, Part 2, Test Ke, Method (class) 3
Industrial corrosive environment/poor environmental control, mixed gas flow test.
21 days at 75% relative humidity and +30°C
Exposure to elevated concentrations of H_2S, (100 ppb), NO_2, (200 ppb) & Cl_2 (20 ppb).
Per IEC 60068-2-52 Salt mist (7 days)
Per IEC 60068-2-43 for H_2S (21 days), 15 ppm
Per IEC 60068-2-42 for SO_2 (21 days), 25 ppm

7 TYPE TESTS

7.1 Insulation

Per EN / IEC 60255-27:
Insulation resistance > 100 MΩ at 500 Vdc
(Using only electronic/brushless insulation tester).

7.2 Creepage Distances and Clearances

Per IEC 60255-27: 2005	Pollution degree 3 overvoltage category III impulse test voltage 5 kV

7.3 High Voltage (Dielectric) Withstand

(EIA RS-232 ports excepted and normally-open contacts of output relays excepted).

(i) As for EN / IEC 60255-27:

2 kV rms AC, 1 minute:
  Between all independent circuits.
  Between independent circuits and case earth (ground).
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.
1 kV rms AC for 1 minute for all D-type EIA(RS)-232 or EIA(RS)-485 ports between the communications port terminals and protective (earth) conductor terminal.
1 kV rms AC for 1 minute between RJ45 ports and the case earth (ground).

(ii) As for ANSI/IEEE C37.90:

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

7.4 Impulse Voltage Withstand Test

As for EN / IEC 60255-27:

(i) Front time: 1.2 µs, Time to half-value: 50 µs,

Peak value: 5 kV, 0.5 J
Between all independent circuits.
Between independent circuits and case earth ground.

(ii) Front time: 1.2 µs, Time to half-value: 50 µs,

Peak value: 1.5kV, 0.5 J
Between RJ45 ports and the case earth (ground).
EIA(RS)-232 & EIA(RS)-485 ports and normally open contacts of output relays excepted.

8 ELECTROMAGNETIC COMPATIBILITY (EMC)

8.1 1 MHz Burst High Frequency Disturbance Test

As for EN / IEC 60255-22-1, 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 and 1 MHz Damped Oscillatory Test

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

8.3 Immunity to Electrostatic Discharge

As for EN / IEC 60255-22-2, EN / IEC 61000-4-2:

15kV discharge in air to user interface, display, communication ports and exposed metalwork.
6kV contact discharge to the screws on the front of the front communication ports.
8kV 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 and EN 61000-4-4: 2004.

Test severity:	Class III and IV:
Amplitude:	2 kV, burst frequency 5kHz (Class III),
Amplitude:	4 kV, burst frequency 2.5kHz (Class IV). Applied directly to auxiliary supply, and applied to all other inputs. (EIA RS232 ports excepted).
Amplitude:	4 kV, burst frequency 5kHz (Class IV). Applied directly to auxiliary supply.

8.5 Surge Withstand Capability

As for IEEE/ANSI C37.90.1:
4 kV fast transient and 2.5 kV oscillatory
applied directly across each output contact, optically isolated input, and power supply circuit.
4 kV fast transient and 2.5 kV oscillatory applied common mode to communications, IRIG-B.

8.6 Surge Immunity Test

As for EN / IEC 61000-4-5, EN / IEC 60255-26:

Time to half-value:	1.2 to 50 µs,
Amplitude:	4 kV between all groups and case earth (ground),
Amplitude:	2 kV between terminals of each group.
Amplitude:	1kV for LAN ports

8.7 Conducted/Radiated Immunity

For RTDs used for tripping applications the conducted and radiated immunity performance is guaranteed only when using totally shielded RTD cables (twisted leads).

8.8 Immunity to Radiated Electromagnetic Energy

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

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

Per IEEE/ANSI C37.90.2: 2004:
80 MHz to 1000 MHz, 1 kHz 80% am and am pulsed modulated.
Field strength of 35V/m.

8.9 Radiated Immunity from Digital Communications

As for EN / IEC61000-4-3, 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%.

8.10 Radiated Immunity from Digital Radio Telephones

As for EN / IEC 61000-4-3: 10 V/m, 900 MHz and 1.89 GHz.

8.11 Immunity to Conducted Disturbances Induced by Radio Frequency Fields

As for EN / IEC 61000-4-6, Level 3, Disturbing test voltage: 10 V.

8.12 Power Frequency Magnetic Field Immunity

As for EN / IEC 61000-4-8, Level 5,
100 A/m applied continuously, 1000 A/m applied for 3 s.
As for EN / IEC 61000-4-9, Level 5,
1000 A/m applied in all planes.
As for EN / IEC 61000-4-10, Level 5,
100 A/m applied in all planes at 100 kHz and 1 MHz with a burst duration of 2 s.

8.13 Conducted Emissions

As for CISPR 22 Class A:
Power supply:
0.15 - 0.5 MHz, 79 dBμV (quasi peak) 66 dBμV (average)
0.5 - 30 MHz, 73 dBμV (quasi peak) 60 dBμV (average)
Permanently connected communications ports:
0.15 - 0.5MHz, 97dBμV (quasi peak) 84dBμV (average)
0.5 - 30MHz, 87dBμV (quasi peak) 74dBμV (average)

8.14 Radiated Emissions

As for CISPR 22 Class A:
30 to 230 MHz, 40 dBμV/m at 10m measurement distance
230 to 1 GHz, 47 dBμV/m at 10 m measurement distance.
1 – 3GHz, 76dBμV/m (peak), 56dBμV/m (average) at 3m measurement distance.
3 – 5GHz, 80dBμV/m (peak), 60dBμV/m (average) at 3m measurement distance.

9 EU DIRECTIVES

9.1 EMC Compliance

2004/108/EC:
Compliance to the European Commission Directive on EMC is claimed via the Technical Construction File route. Product Specific Standards were used to establish conformity:
EN 60255-26

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.

EN 60255-27

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.

II (2) G

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.

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 EN / IEC 60255-21-1 — Response Class 2
Endurance Class 2

10.2 Shock and Bump

Per EN / IEC 60255-21-2 — Shock response Class 2
Shock withstand Class 1
Bump Class 1

10.3 Seismic Test

Per EN / IEC 60255-21-3: Class 2

11 P34X THIRD PARTY COMPLIANCES

11.1 Underwriters Laboratory (UL)

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

Original Issue Date: 05/10/2002

11.2 Energy Networks Association (ENA)

Certificate Number: 104 Issue 2
Assessment Date: 16-04-2004

12 PROTECTION FUNCTIONS

12.1 Generator Differential

Pick-up:	Formula ±5%
Drop-off:	95% of setting ±5%
Operating time:	<30 ms for currents applied at 4x pickup level or greater
Repeatability:	<7.5%
Disengagement time:	<40 ms

12.2 Transformer Differential

12.2.1 Low Set Biased Differential

Pick-up:	Formula ±5%
Drop-off:	95% x formula ±5%
Pick-up and drop-off repeatability:	<1%
Operating time:	<33 ms for currents applied at 3x pickup level or greater
DT operating time:	±2% or 33 ms whichever is greater for currents applied at 3x pickup level or greater
Operating time repeatability:	< 2 ms
Disengagement time:	<40 ms

12.2.2 High Set Operation

Operating time:	< 25 ms.
Reset time:	< 40 ms
Operation time repeatability:	< 2 ms
Pick-up and drop-off repeatability:	< 2%

12.2.3 2nd Harmonic Blocking

Pick-up:	Setting ±5%
Drop-off:	0.95 of setting ±5%
Pick-up and drop-off repeatability:	<2%

12.2.4 5th Harmonic Blocking(P343/P344)

Pick-up:	Setting ±10%
Drop-off:	0.95 of setting ±10%
Pick-up and drop-off repeatability:	<2%

12.2.5 5th Harmonic Blocking (P345)

Pick-up:	Setting ±5%
Drop-off:	0.95 of setting ±5%
Pick-up and drop-off repeatability:	<2%

12.3 Circuitry Fault Alarm

Pick-up:	Formula ±5%
Drop-off:	0.95 x formula ±5%
Pick-up and drop-off repeatability:	<1%
Instantaneous operating time:	<33 ms at 3x pick-up value
DT operating time:	2% or 33 ms whichever is greater for currents applied at 3x pickup level or greater
Disengagement time:	<40 ms
Operating time repeatability:	<3 ms

12.4 Through Fault Monitoring

TF I> pick-up:	Setting ±5%
TF I> drop-off:	0.95 of setting ±5%
TF I^2t> pick-up:	setting ±2% or $5A^2s$ whichever is greater
Pick-up repeatability:	<5%
Operating time repeatability:	<50 ms

12.5 Reverse/Low Forward/Overpower (3-Phase)

Pick-up:	Setting ±10%
Reverse/Overpower Drop-off:	0.95 of setting ±10%
Low forward power Drop-off:	1.05 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

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

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 Negative Phase Sequence Overpower

Pick-up:	Setting ±5%
Drop-off:	0.95 of setting ±5%
Repeatability (operating threshold):	<1%
Operating time:	±2% or 70 ms whichever is greater
Disengagement time:	<35 ms
Repeatability (operating times):	<10 ms

12.8 Field Failure

Mho characteristic Pick-up:	Characteristic shape ±5%
Linear characteristic Pick-up:	Characteristic shape ±10%
Mho characteristic Drop-off:	105% of setting ±5%
Linear characteristic Drop-off:	105% of setting ±10%
Operating time:	±2% or 50 ms whichever is greater
Repeatability:	<1%
Disengagement time:	<50 ms

12.9 Negative Phase Sequence Thermal

Pick-up:	Formula ±5%
Drop-off:	95% of pick-up ±5%
Operating time:	±5% or 55 ms whichever is greater
Repeatability:	<5%
Disengagement time:	<30 ms

12.10 System Back-up

12.11 Voltage Dependent Overcurrent

VCO threshold Pick-up:	Setting ±5%
Overcurrent Pick-up:	Formula ±5%
VCO threshold Drop-off:	1.05 x Setting ±5%
Overcurrent Drop-off:	0.95 x formula ±5%
Operating time:	<50 ms
Repeatability:	< 2.5%
IDMT operation:	±5% or 40 ms whichever is greater
Definite time operation:	±5% or 50 ms whichever is greater
tRESET:	±5% or 50 ms whichever is greater

12.12 UnderImpedance

Pick-up:	Setting ±5%
Drop-off:	105% of setting ±5%
Operating time:	±2% or 50 ms whichever is greater
Repeatability:	<5%
Disengagement time:	<50 ms
tRESET:	±5%
Instantaneous operating time:	<50 ms

12.13 4-Stage Directional/Non-Directional Overcurrent

Pick-up:	Setting ±5%
Drop-off:	0.95 x Setting ±5%
Minimum trip level (IDMT):	1.05 x Setting ±5%
IDMT characteristic 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 accuracy (RCA ±90º):	±2 º hysteresis 2 º
Characteristic UK:	IEC 6025-3…1998
Characteristic US:	IEEE C37.112…1996

* Under reference conditions

12.14 4-Stage Negative Phase Sequence Overcurrent

I2>Pick-up:	Setting ±5%
I2> Drop-off:	0.95 x Setting ±5%
Vpol Pick-up:	Setting ±5%
Vpol Drop-off:	0.95 x Setting ±5%
DT operation:	±2% or 60 ms whichever is greater
Disengagement time:	<35 ms
Directional accuracy (RCA ±90º):	±2º hysteresis <1%
Repeatability (operating times):	<10 ms

12.15 Thermal Overload Gen Thermal

Setting accuracy:	±5%
Reset:	95% of thermal setting ±5%
Thermal alarm Pick-up:	Calculated trip time ±5%
Thermal overload Pick-up:	Calculated trip time ±5%
Cooling time accuracy:	±6% of theoretical
Repeatability:	<2.5%

12.16 Transformer Thermal and Loss of Life

12.16.1.1 Transformer Thermal

Hot Spot> Pick-up:	Expected pick-up time ±5% (expected pick-up time is the time required to reach the setting)
Hot Spot> DT:	±5% or 200 ms whichever is greater
Top Oil> Pick-up:	Expected Pick-up Time ±5% (expected pick-up time is the time required to reach the setting)
Top Oil> DT:	±5% or 200 ms whichever is greater
Pick-up repeatability:	<2.5%
Time repeatability:	<20 ms

12.16.1.2 Loss of Life

FAA> Pick-up:	Formula:	±5%
Loss of Life> Pick-up:	Expected Pick-up Current	±5%
Repeatability:	<2.5%	
FAA> DT:	±5% or 200 ms whichever is greater	

12.17 2-Stage Non-Directional Earth Fault

Pick-up:	Setting ±5%
Drop-off:	0.95 x Setting ±5%
IDMT trip level elements:	1.05 x Setting ±5%
IDMT characteristic shape:	±5% or 40 ms whichever is greater*
IEEE reset:	±5% or 40 ms whichever is greater
DT operation:	±2% or 60 ms whichever is greater
DT reset:	±5%
Repeatability:	2.5%

12.18 Rotor Earth Fault

Pick-up:	Setting ±10% (1 k to 5 kΩ) Setting ±5% (5 k to 80 kΩ)
Drop-off:	1.05 x Setting ±10% (1 k to 5 kΩ) 1.02 x Setting ±5% (5 k to 80 kΩ)
Repeatability:	<1%
DT operation for Double ended connection:	±2% or 2.5/fs whichever is greater
Disengagement time:	<2.5/fs
DT operation for Single ended connection:	
Field voltage 0 to 600 V DC	±2% or 2.5/fs whichever is greater
Disengagement time:	<2.5/fs
Field voltage 601 to 1200 V DC	±2% or 3.5/fs whichever is greater
Disengagement time:	<3.5/fs

(fs – injection frequency, 0.25/0.5/1 Hz)

12.19 Sensitive Directional Earth Fault

12.19.1 SEF Accuracy

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

12.19.2 Wattmetric SEF Accuracy

Pick-up P=0W:	ISEF> ±5% or 5 mA
Pick-up P>0W:	P> ±5%
Drop-off P=0W:	(0.95 x ISEF >) ±5% or 5 mA
Drop-off P>0W:	0.9 x P> ±5%
Boundary accuracy:	±5° with 1° hysteresis
Repeatability:	1%

12.19.3 Polarizing Quantities Accuracy

Accuracy

Operating boundary Pick-up:	±2° of RCA ±90°
Hysteresis:	<3°
ISEF>Vnpol Pick-up:	Setting ±10%
ISEF>Vnpol Drop-off:	0.9 x Setting or 0.7V (whichever is greater) ±10%

12.20 Restricted Earth Fault

12.20.1 Low impedance biased REF

Pick-up:	Setting formula ±5%
Drop-off:	0.9 x formula ±5%
Pick-up and drop-off repeatability:	<5%
Operating time:	<50 ms
Disengagement time:	<30 ms

12.20.2 High Impedance REF

Pick-up:	Setting ±5%
Operating time:	<30 ms

12.21 Transient Overreach and Overshoot

Additional tolerance due to increasing X/R ratios:	±5% over X/R 1 to 90
Overshoot of overcurrent elements:	<40 ms
Disengagement time:	<60 ms (65 ms SEF)

12.22 Neutral Displacement/Residual Overvoltage

DT/IDMT Pick-up:	Setting ±5%
Drop-off:	0.95 x Setting ±5%
IDMT characteristic shape:	±5% or 55 ms whichever is greater
DT operation:	±2% or 55 ms whichever is greater
Instantaneous operation	<55 ms
Reset:	<35 ms
Repeatability:	<1%

12.23 100% Stator Earth Fault (3rd Harmonic)

VN3H</VN3H> Pick-up:	Setting ±5%
V/P/Q/S<Inh:	Setting ±0.5%
VN3H< Drop-off:	105% of Pick-up ±5%
VN3H> Drop-off:	95% of Pick-up ±5%
V/P/Q/S<Inh Drop-off:	95% of Pick-up ±0.5%
Operating time:	±0.5% or 50 ms whichever is greater
Repeatability:	< 0.5%
Disengagement/reset time:	<50 ms

12.24 100% Stator Earth Fault, 64S (Low Frequency Injection)

R<1/R<2 Pick-up:	Setting ±5% (for R≤300Ω), ±7.5% (for R> 300 Ω) or 2 Ω whichever is greater
I>1/V<1/I<1 Pick-up:	Setting ±5%
R<1/R<2 Drop-off:	105% of setting ±5% (R≤300Ω), ±7.5% (R>300Ω)
V<1/I<1 Drop-off:	105% of setting ±5%
I>1 Drop-off:	95% of setting ±5%
Repeatability:	<1%
R<1/R<2/I>1/V<1/I<1 operating time without bandpass filter:	±2% or 220 ms whichever is greater
R<1/R<2/I>1/V<1/I<1 disengagement time:	<120 ms
Repeatability:	100 ms
R<1/R<2/I>1/V<1/I<1 operating time with bandpass filter:	±2% or 1.2 s whichever is greater
R<1/R<2/I>1/V<1/I<1 disengagement time:	<700 ms
Repeatability:	<100 ms

12.25 Volts/Hz

Pick-up:	Setting ±2%
Drop-off:	98% or pick-up ±2%
Repeatability (operating threshold):	<1%
IDMT operating time:	±5% or 60 ms whichever is greater
Definite time:	±2% or 30 ms whichever is greater
Disengagement time:	<50 ms
Repeatability (operating times):	<10 ms
V/Hz measurement:	±1%

12.26 Unintentional Energization at Standstill (Dead Machine)

I > Pick-up:	Setting ±5%
V< Pick-up:	Setting ±5%
I > Drop-off:	95% of setting ±5%
V< Drop-off:	105% of setting ±5%
Operating time:	±2% or 50 ms whichever is greater
Repeatability:	2.5% or 10 ms whichever is greater

12.27 Undervoltage

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%

12.28 Overvoltage

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

12.29 NPS Overvoltage

Pick-up:	Setting ±5%
Drop-off:	0.95 x Setting ±5%
Repeatability (operating threshold):	<1%
DT operation:	±2% or 65 ms whichever is greater
Instantaneous operation (normal mode):	<60 ms
Instantaneous operation (accelerated mode):	<45 ms
Disengagement time:	<35 ms
Repeatability (operating times):	<10 ms

12.30 Underfrequency

Pick-up:	Setting ±0.01 Hz
Drop-off:	(Setting +0.025 Hz) ±0.01 Hz
DT operation:	±2% or 50 ms whichever is greater.

The operation also includes a time for the relay to frequency track (20 Hz/second)

12.31 Overfrequency

Pick-up:	Setting ±0.01 Hz
Drop-off:	(Setting -0.025 Hz) ±0.01 Hz
DT operation:	±2% or 50 ms whichever is greater.

The operation also includes a time for the relay to frequency track (20 Hz/second)

12.32 Rate of Change of Frequency ‘df/dt’

12.32.1 Accuracy

12.32.1.1 Fixed Window (P342/P343/P344)

Pick-up:	Setting ±0.05 Hz/s or ±3% whichever is greater
Repeatability:	<5%

12.32.1.2 Fixed Window (P345)

Pick-up:	Setting ±0.05 Hz/s or ±15% whichever is greater (df/dt < 1.5 Hz/s)
Repeatability:	<5%

12.32.1.3 Rolling Window (P342/P343/P344)

Pick-up:	Setting ±0.01 Hz/s or ±3% whichever is greater
Repeatability:	<3%

12.32.1.4 Rolling Window (P345)

Pick-up:	Setting ±0.01 Hz/s or ±10% whichever is greater (df/dt < 1.5 Hz/s)
Repeatability:	<5%

12.32.1.5 Frequency Low, Frequency High

Pick-up:	Setting ±2% or ±0.08 Hz/s whichever is greater
Repeatability:	<5%

12.32.2 Delay Time

12.32.2.1 Fixed Window (P342/P343/P344)

Dead time:	Setting ±2% or ±(40+20*X*Y) ms
Repeatability:	<20 ms

12.32.2.2 Rolling Window (P342/P343/P344)

Dead time:	Setting ±2% or ±(60+20*X+5*Y) ms
Repeatability:	<20 ms

12.32.2.3 Fixed Window (P345)

Dead time:	Setting ±2% or ±(100+20*X*Y) ms
Repeatability:	<30 ms

12.32.2.4 Rolling Window (P345)

Dead time:	Setting ±2% or ±(150+20*X*Y) ms
Note:	X = average cycles, Y = Iterations
Repeatability:	<30 ms

12.33 Generator Abnormal Frequency

Pick-up:	Setting ±0.01 Hz
Drop-off lower threshold:	(Setting -0.025 Hz) ±0.01 Hz
Drop-off upper threshold:	(Setting +0.025 Hz) ±0.01 Hz
Repeatability (operating threshold):	<1%
Accumulation time:	±2% or 50 ms whichever is the greater
Dead time:	±2% or 50 ms whichever is the greater
Repeatability (operating times):	<10 ms

12.34 Resistive Temperature Detectors

Pick-up:	Setting ±1ºC
Drop-off:	(Setting -1ºC)
Operating time:	±2% or <3 s

12.35 CB Fail

12.35.1 Timer Accuracy

Accuracy

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

12.35.2 Undercurrent Accuracy

Accuracy

Pick-up:	±10% or 0.025 In, whichever is greater
Operating time:	<12 ms
Timers:	2 ms or 2%, whichever is greater
Reset:	<15 ms

Pick-up:	Setting ±10%
Drop-off:	1.05 x Setting ±10%
Pick-up and Drop-off Repeatability:	<5%
Operating time:	<15ms
Reset:	<15ms
Time repeatability:	10ms

12.36 Pole Slipping

12.36.1 Accuracy

Lens Characteristic Pick-up:	Setting ±5%
Blinder Pick-up:	±1º
Reactance line Pick-up:	Setting ±5%
Lens DO characteristic Lens Angle:	Adjusted by -5º, (ZA+ZB) + 5%
Lens DO Drop-off:	Lens DO characteristic ±5%
Blinder DO characteristic:	Blinder displaced by (ZA+ZB)/2 x tan 87.5º
Blinder DO Drop-off:	Blinder DO characteristic ±1º
Repeatability:	<2.5%
T1, T2 and Reset Timer:	±2% or 10 ms whichever is greater

12.36.2 Hysteresis

Hysteresis is applied to the lenticular characteristic and to the blinder as soon as they pick up individually. Hysteresis is not required for the reactance line as Zone 1 or Zone 2 is determined at a single point when the locus traverses the blinder.

For the lens, the hysteresis consists of an angle of 5° subtracted from the α setting to increase the lens size and an increment of 5% applied to ZA and ZB to extend the reach. Hysteresis for the blinder is dependent on the mode of operation. For generating mode, the blinder is adjusted to the right, for motoring mode, the blinder is adjusted to the left, with a distance which is equivalent to an angle separation of 175°.

This is shown in the ***Hysteresis of the pole slipping characteristic*** diagram. This distance is equivalent to (ZA + ZB)/2*tan87.5°.

For both characteristics the hysteresis is reset when the impedance locus leaves the lens.

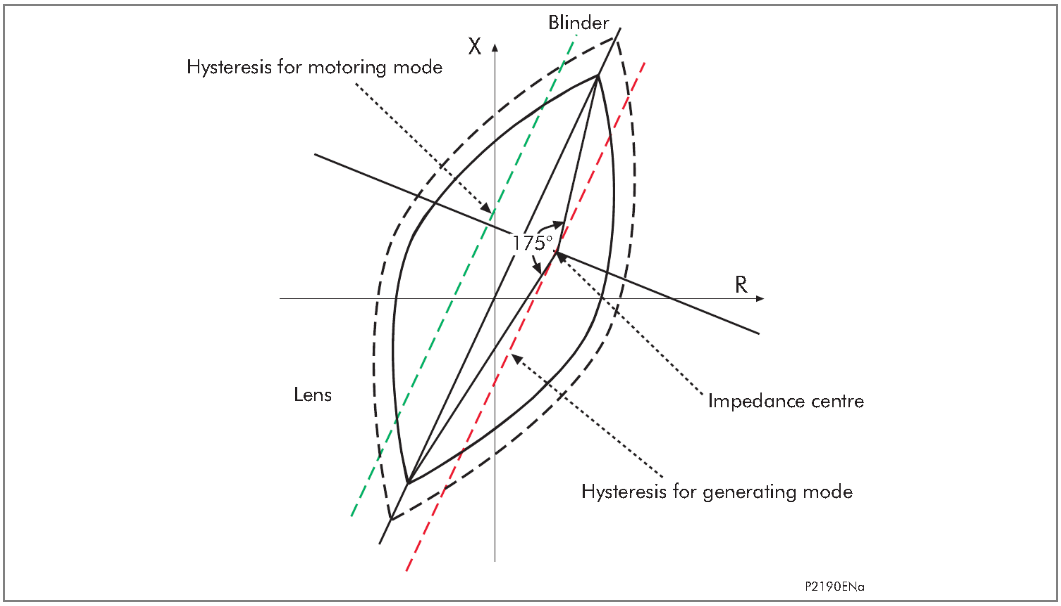

Figure 1 - Hysteresis of the pole slipping characteristic

13 SUPERVISORY 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
CTS block operation:	< 1 cycle
CTS reset:	< 35 ms

13.3 Differential CTS

Accuracy

CTS I1 Pick-up ratio:	Setting ±5%
CTS I2/I1>1 Pick-up ratio:	0.95 x setting ±5%
CTS I2/I1>2 Pick-up ratio:	setting ±5%
CTS I1 Drop-off ratio:	0.95 x setting ±5%
CTS I2/I1>1 Drop-off ratio:	setting ±5%
CTS I2/I1>2 Drop-off ratio:	0.95 x setting ±5%
Pick-up and drop-off repeatability:	<1%
Time delay operation:	±2% or 33 ms whichever is greater
CTS terminal block operation:	<33 ms
CTS differential block operation:	<33 ms
Operating time repeatability:	<2 ms
CTS Disengagement time:	<40 ms

14 SYSTEM CHECKS

14.1 Voltage Monitors

14.1.1 Gen/Bus Voltage Monitors - Over/Live/Diff Voltage

Pick-up:	setting ±3% or ±0.1 V whichever is greater
Drop-off:	(0.98 x Setting) ±3% or ±0.1 V whichever is greater
Repeatability:	<1%

14.1.2 Gen/Bus Voltage Monitors - Bus Under/Dead Voltage

Pick-up:	Setting ±3% or ±0.1 V whichever is greater
Drop-off:	(1.02 x Setting) ±3% or ±0.1 V whichever is greater
Repeatability:	<1%

14.1.3 Gen/Bus Voltage Monitors - Generator Underfrequency

Pick-up:	Setting ±0.01 Hz
Drop-off:	(Setting +0.01 Hz) ±0.01 Hz
Repeatability:	<1%

14.1.4 Gen/Bus Voltage Monitors - Generator Overfrequency

Pick-up:	Setting ±0.01 Hz
Drop-off:	(Setting +0.01 Hz) ±0.01 Hz
Repeatability:	<1%

14.2 Check Synch (CS)

14.2.1 CS1 Phase Angle

Pick-up:	(Setting-2°) ±1°
Drop-off:	(Setting-1°) ±1°
Repeatability:	<1%

14.2.2 CS1 Slip Freq

Pick-up:	Setting ±0.01 Hz
Drop-off:	(0.95 x Setting) ±0.01 Hz
Repeatability:	<1%

14.2.3 CS1 Slip Timer

Timers:	Setting ±1% or 40 ms whichever is greater
Reset time:	< 30 ms
Repeatability:	<10ms

14.2.4 CS2 Phase Angle

Pick-up:	(Setting-2°) ±1°
Drop-off:	(Setting-1°) ±1°
Repeatability:	<1%

14.2.5 CS2 Slip Freq

Pick-up:	Setting ±0.01 Hz
Drop-off:	(0.95 x Setting) ±0.01 Hz
Repeatability:	<1%

14.2.6 CS2 Slip Timer

Timer:	Setting ±1% or 40 ms whichever is greater
Reset time:	< 30 ms
Repeatability:	<1%

14.2.7 CS2 Advanced CB Compensation Phase Angle

Pick-up:	0°±1°
Drop-off:	2°±1°
Repeatability:	<1%

14.2.8 CS2 CB Closing Timer

Timer:	<30 ms
Repeatability:	<10 ms

14.3 System Split (SS)

14.3.1 Phase Angle

Pick-up:	(Setting+2°) ±1°
Drop-off:	(Setting+1°) ±1°
Repeatability:	<1%

14.3.2 Undervoltage

Pick-up:	Setting ±3%
Drop-off:	1.02 x Setting
Repeatability:	<1%

14.3.3 Timer

Timers:	Setting ±1% or 40 ms whichever is greater
Reset time:	<30 ms
Repeatability:	<10 ms

15 PLANT SUPERVISION

15.1 CB State Monitoring Control and Condition Monitoring

Accuracy

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

15.2 Programmable Scheme Logic (PSL)

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

15.3 Measurements and Recording Facilities

Accuracy

Current:	0.05 to 3 In:	±1% or 3 mA of reading
Voltage:	0.05 to 2 Vn:	±1% of reading
Power (W):	0.2 to 2 Vn, 0.05 to 3 In:	±5% of reading at unity power factor
Reactive Power (VArs):	0.2 to 2 Vn, 0.05 to 3 In:	±5% of reading at zero power factor
Apparent Power (VA):	0.2 to 2 Vn, 0.05 to 3 In:	±5% of reading
Energy (Wh):	0.2 to 2 Vn, 0.2 to 3 In:	±5% of reading at zero power factor
Energy (Varh):	0.2 to 2 Vn, 0.2 to 3 In:	±5% of reading at zero power factor
Phase accuracy:	-180° to 180°:	±1.0°
Frequency:	5 to 70 Hz:	±0.025 Hz

15.4 IRIG-B and Real Time Clock

Performance

Year 2000:	Compliant
Real time accuracy:	< ±1 second / day
External clock synchronisation:	Conforms to IRIG standard 200-98, format B

Features

Real time 24 hour clock settable in hours, minutes and seconds
Calendar settable from January 1994 to December 2092
Clock and calendar maintained via battery after loss of auxiliary supply
Internal clock synchronization using IRIG-B Interface for IRIG-B signal is BNC

15.5 Current Loop Input and Outputs

Accuracy

Current loop input accuracy:	±1% of full scale
CLI drop-off threshold Under:	setting ±1% of full scale
CLI drop-off threshold Over:	setting ±1% of full scale
CLI sampling interval: 50 ms	
CLI instantaneous operating time:	< 200 ms for 20 Hz to 70 Hz; < 300 ms for 5 Hz to 20 Hz
CLI DT operating time:	±2% setting or 150 ms whichever is the greater for 20 Hz to 70 Hz; ±2% setting or 200 ms whichever is the greater for 5 Hz to 20 Hz
CLO conversion interval:	50 ms
CLO latency:	< 1.07 s or <70 ms depending on CLO output parameter's internal refresh rate - (1 s or 0.5 cycle)
Current loop output accuracy:	±0.5% of full scale
Repeatability:	<5%

CLI - Current Loop Input
CLO - Current Loop Output

Other Specifications

CLI load resistance 0-1 mA:	< 4 kΩ
CLI load resistance 0-1 mA/0-20 mA/4 20 mA:	<300 Ω
Isolation between common input channels:	zero
Isolation between input channels and case earth/other circuits:	2 kV rms for 1 minute
CLO compliance voltage 0-1 mA/0 10 mA:	10 V
CLO compliance voltage 0-20 mA/4 20 mA:	8.8 V
Isolation between common output channels:	zero
Isolation between output channels and case earth/other circuits:	2 kV rms for 1 minute

15.6 Disturbance Records

Accuracy

Magnitude and relative phases:	±5% of applied quantities
Duration:	±2%
Trigger Position:	±2% (minimum 100 ms)

Record length: 50 records each 1.5 s duration (75 s total memory) with 8 analog channels and 32 digital channels (Courier, MODBUS, DNP 3.0), 8 records each 3 s (50 Hz) or 2.5 s (60 Hz) duration (IEC60870-5-103).

15.7 Event, Fault & Maintenance Records

Maximum 512 events in a cyclic memory
Maximum 5 fault records
Maximum 10 maintenance records

Accuracy

Event time stamp resolution: 1 ms

16 SETTINGS, MEASUREMENTS AND RECORDS LIST

16.1 Settings List

Global Settings (System Data)

Language: English/French/German/Spanish/Italian/Chinese (ordering option)
Frequency: 50/60Hz

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…10.00s
Trip pulse time: 0.10…5.00s
Man close delay: 0.01…600.00s
CB healthy time: 0.01…9999.00s
Check sync time: 0.01…9999.00s
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
Power:	Disabled, Enabled
Field Failure:	Disabled, Enabled
NPS Thermal:	Disabled, Enabled
System Back-up:	Disabled, Enabled
Overcurrent:	Disabled, Enabled
Thermal Overload:	Disabled, Enabled
Differential:	Disabled, Enabled
Earth Fault:	Disabled, Enabled
Rotor EF	Disabled, Enabled
SEF/REF/Spower:	Disabled or SEF/REF or Sensitive Power
Residual O/V NVD:	Disabled, Enabled
100% Stator EF:	Disabled, Enabled
V/Hz:	Disabled, Enabled
df/dt:	Disabled, Enabled
Dead Machine:	Disabled, Enabled
Volt Protection:	Disabled, Enabled
Freq Protection:	Disabled, Enabled
RTD Inputs:	Disabled, Enabled
CB Fail:	Disabled, Enabled
Supervision:	Disabled, Enabled
Pole Slipping:	Disabled, Enabled
Input Labels:	Invisible, Visible
Output Labels:	Invisible, Visible
RTD Labels:	Invisible, Visible
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
CLIO Inputs:	Disabled/Enabled
CLIO Outputs:	Disabled/Enabled
System Checks:	Disabled/Enabled
Ctrl I/P Config:	Invisible/Visible
Ctrl I/P Labels:	Invisible/Visible
Direct Access:	Disabled/Enabled/Hotkey
Function Keys:	Invisible/Visible
VIR I/P Labels:	Invisible, Visible
VIR O/P Labels:	Invisible, Visible
Usr Alarm Labels:	Invisible, Visible
RP1 Read Only:	Enabled, Disabled
RP2 Read Only:	Enabled, Disabled
NIC Read Only:	Enabled, Disabled
LCD Contrast:	0…31

16.5 System Data

Language:	English/French/German/Spanish English/French/German/Russian Chinese/English/French
Sys Fn Links:	Bit 00 = Trip LED S/Reset
Description:	User defined text string to describe the device
Plant Reference:	User defined text string to describe the plant
Frequency:	50/60 Hz

IEC61850 Edition	Edition 1, Edition 2
ETH COMM Mode	Dual IP, PRP, HSR

16.6 CT and VT Ratios

Main VT Primary:	100...1MV
Main VT Sec'y:	80...140 V (100/120 V) 320…560 V (380/480 V)
C/S VT Primary:	100 V...1 MV
C/S VT Secondary:	80...140 V (100/120 V) 320…560 V (380/480 V)
VN1 Primary:	100…1MV
VN1 VT Sec'y:	80…140 V (100/120 V) 320…560 V (380/480 V)
VN2 Primary (P344/P345):	100…1MV
VN2 VT Sec'y (P344/P345):	80…140 V (100/120 V) 320…560 V (380/480 V)
Ph CT Polarity/Ph CT1 Polarity:	Standard/Inverted
Phase CT Primary or Phase CT1 Primary:	1A…60 kA
Phase CT Sec'y or Phase CT1 Sec'y:	1A/5A
Ph CT2 Polarity:	Standard/Inverted
Phase CT2 Primary:	1A…60 kA
Phase CT2 Sec'y:	1A/5A
E/F CT Polarity:	Standard/Inverted
E/F CT Primary:	1A…60 KA
E/F CT Sec'y:	1A/5A
Isen CT Polarity:	Standard, Inverted
ISen CT Primary:	1A…60 KA
ISen CT Sec'y:	1A/5A

16.7 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
Security Event:	Disabled/Enabled
DDB 31 - 0:	(up to):
DDB 2047 - 2016:	Binary function link strings, selecting which DDB signals will be stored as events, and which will be filtered out.

16.8 Oscillography (Disturbance Recorder)

Duration: 0.10…10.50s
Trigger Position: 0.0…100.0%
Trigger Mode: Single/Extended
Analog Channel 1: (up to): depending on model
Analog Channel 15:
Disturbance channels selected from:
IA-1/IB-1/IC-1/IA-2/IB-2/IC-2/IN/VA/VB/VC/ VN1/VN2/ISensitive/ I64S/ V64S/ Frequency/ 64R CL Input Raw/ 64R R Fault Raw/ 64R R Fault/CS Voltage (depending on model)
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): No Trigger or
Input 32 Trigger: Trigger L/H (Low to High) or
Trigger H/L (High to Low)

16.9 Measured Operating Data (Measure't Setup)

Default Display: Banner / 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

16.10 Communications

RP1 Protocol:	Courier / IEC60870-5-103 / Modbus / DNP 3.0
RP1 Address:	0…255 (Courier) 1…247 (Modbus) 0...254 (IEC60870-5-103) 0...65519 (DNP 3.0)
RP1 InactivTimer:	1…30mins
RP1 Baud Rate:	9600/19200 bits/s (IEC 870-5-103) 1200, 2400, 4800, 9600, 19200, 38400 bit/s (DNP 3.0) 9600/19200/38400 bits/s (Courier/Modbus)
RP1 Parity:	Odd/Even/None (MODBUS/DNP 3.0)
RP1 Meas Period:	1…60s (IEC60870-5-103)
RP1 PhysicalLink:	Copper or Fiber Optic
DNP Time Sync:	Disabled/Enabled
Modbus IEC Time:	Standard/Reverse
RP1 CS103Blcking:	Disabled / Monitor Blocking / Command Blocking
RP1 Port Config:	K Bus / EIA485 (RS485) (Courier)
RP1 Comms Mode:	IEC 60870 FT1.2 / IEC 60870 10-Bit No parity (Courier)
Meas Scaling:	Normalised / Primary / Secondary (DNP 3.0)
Message Gap (ms):	0...50 (DNP 3.0)
DNP Need Time:	1...30 mins
DNP App Fragment:	100...2048
DNP App Timeout:	1...120 s
DNP SBO Timeout:	1...10 s
DNP Link Timeout:	0...120s

Note *If RP1 Port Config is K Bus the baudrate is fixed at 64 kbits/s*

16.11 Optional Ethernet Port

ETH Tunl Timeout: 1...30 mins

16.12 Redundancy Configuration (Dual IP Ethernet Versions)

IP Address:	000.000.000.000...255.255.255.255
Subnet Mask:	000.000.000.000...255.255.255.255
Gateway:	000.000.000.000...255.255.255.255

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

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

Note *If RP2 Port Config is K Bus the baud rate is fixed at 64 kbits/s*

17 COMMISSION TESTS

17.1 Monitor Bits

Monitor bit 1:	Binary function link strings, selecting which
(up to):	DDB signals have their status visible in the
Monitor bit 8:	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

17.2 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

17.3 Opto Coupled 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%

17.4 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):	Latched/Pulsed
Control Input 32:	
Ctrl Command 1 (up to):	On/Off / Set/Reset / In/Out / Enabled/Disabled
Ctrl Command 32:	

17.5 Function Keys

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

17.6 IEC 61850 GOOSE

GoEna:	0000000000000000(bin)... 1111111111111111(bin)
Pub.Simul.Goose:	0000000000000000(bin)... 1111111111111111(bin)
Sub.Simul.Goose:	No/Yes

17.7 Security Config

Front Port:	Disabled/Enabled
Rear Port 1:	Disabled/Enabled
Rear Port 2:	Disabled/Enabled
ETH Port 1:	Disabled/Enabled
ETH Port 1/2:	Disabled/Enabled
ETH Port 2/3:	Disabled/Enabled
ETH Port 3:	Disabled/Enabled

18 PROTECTION FUNCTIONS (IN MULTIPLE GROUPS)

18.1 System Config

Winding Type:	Generator / Gen-Xformer
Ref Power S:	0.1…5000 M
HV Connection:	D-Delta / Y-Wye / Z-Zigzag
HV Grounding:	Grounded / Ungrounded
HV Nominal:	100 V to 1 MV
%Reactance:	1.00% to 100.00%
LV Vector Group:	0 to 11
LV Connection:	D-Delta / Y-Wye / Z-Zigzag
LV Grounding:	Grounded / Ungrounded
LV Nominal:	100 V to 1 MV
Phase Sequence:	Standard ABC/Reverse ACB
VT Reversal:	No Swap/A-B Swapped/B-C Swapped/C-A Swapped
CT1 Reversal:	No Swap/A-B Swapped/B-C Swapped/C-A Swapped
CT2 Reversal:	No Swap/A-B Swapped/B-C Swapped/C-A Swapped
C/S Input:	A-N, B-N, C-N, A-B, B-C, C-A
C/S V Ratio Corr:	0.100...2.000
Main VT Vect Grp:	0...11
Main VT Location:	Gen/Bus

18.2 Generator Differential Protection

GenDiff Function:	Disabled/Percentage Bias or High Impedance or Interturn
Gen Diff Is1:	0.05…0.50 In
Gen Diff k1:	0…20%
Gen Diff Is2:	1…5.0 In
Gen Diff k2:	20…150.00%
Interturn Is_A:	0.05…2.0 In
Interturn Is_B:	0.05…2.0 In
Interturn Is_C:	0.05…2.0 In
Interturn Delay:	0.00…100.0 s

18.3 Xformer Diff Protection

Xform Diff Func:	Disabled, Enabled
Set Mode:	Simple/Advance
Xform Is1:	0.05 to 2.50 PU
Xform K1:	0 to 150%
Xform Is2:	0.10 to 10.0 PU
Xform K2:	15 to 150%
Xform tDiff:	0 to 10.00 s
Xform Is-CTS:	0.10 to 2.50 PU
Xform HS1 Status:	Disabled, Enabled
Xform Is-HS1:	2.50 to 16.0 PU
Xform HS2 Status:	Disabled, Enabled
Xform Is-HS2:	2.50 to 16.0 PU

Zero seq filt HV:	Disabled, Enabled
Zero seq filt LV:	Disabled, Enabled
2nd harm blocked:	Disabled, Enabled
Xform Ih(2)%>:	5 to 50%
Cross blocking:	Disabled, Enabled
5th harm blocked:	Disabled, Enabled
Xform Ih(5)%>:	0 to 100%
Circuitry Fail:	Disabled, Enabled
Is-cctfail>:	0.03 to 1.00 PU
K-cctfail:	0 to 50%
tls-cctfail>:	0 to 10.0 s

18.4 Reverse/Low Forward/Overpower (3-Phase)

Operating mode:		Generating or Motoring
Power 1 Function:		Reverse or Low forward or Over
-P>1 Setting (reverse power/P<1 Setting (Low forward power)/ P>1 Setting (Overpower):	1…300.0 W	(1A, 100 V/120 V)
	4…1200.0 W	(1A, 380 V/480 V)
	5…1500.0 W	(5A, 100 V/120 V)
	20…6000.0 W	(5A, 380 V/480 V)
Equivalent Range in % Pn:		0.5%…157%
Power 1 Time Delay:		0.00…100.0 s
Power 1 DO Timer:		0.00…100.0 s
P1 Poledead Inh:		Disabled, Enabled
Power 2 as Power 1		

18.5 Sensitive/Reverse/Low Forward/Overpower (1-Phase)

Operating mode:	Generating or Motoring	
Sen Power1 Func:	Reverse or Low forward or Over	
Phase Selection:	A, B or C	

Sen -P>1 Setting (Reverse Power)/Sen <P Setting (Low Forward Power)/Sen >P Setting

(Overpower):	0.3…100.0 W	(1A, 100/120 V)
	1.20…400.0 W	(1A, 380/480 V)
	1.50…500.0 W	(5A, 100/120 V)
	6.0…2000.0 W	(5A, 380/480 V)
Equivalent range in %Pn:	0.5%…157%	
Sen Power 1 Delay:	0.00…100.0 s	
Power 1 DO Timer:	0.00…100.0 s	
P1 Poledead Inh:	Disabled, Enabled	
Comp angle θC:	-5º …+5.0º	
Sen Power2 as Sen Power 1		

18.6 Negative Phase Sequence (NPS) Overpower

S2> CT Source:	IA-1 IB-1 IC-1/IA-2 IB-2 IC-2
S2>1 Status:	Disabled, Enabled
S2>1 Setting:	0.10…30.00 In VA (100/120 V)
	0.40…120.00 In VA (380/480 V)
S2> 1 Time Delay:	0.00…100.00 s

18.7 Field Failure

FFail Alm Status:	Disabled, Enabled	
FFail Alm Angle:	15°…75°	
FFail Alm Delay:	0.00…100.0 s	
FFail 1 Status:	Disabled, Enabled	
FFail 1 -Xa1:	0.0…40.0 Ω	(1A, 100/120 V)
	0.0…8.0 Ω	(5A, 100/120 V)
	0…160 Ω	(1A, 380/480 V)
	0.0…32.0 Ω	(5A, 380/480 V)
FFail 1 Xb1:	25…325.0 Ω	(1A, 100/120 V)
	5…65.0 Ω	(5A, 100/120 V)
	100…1300 Ω	(1A, 380/480 V)
	20…260.0 Ω	(5A, 380/480 V)
FFail 1 Time Delay:	0…100 s	
FFail 1 DO Timer:	0…100 s	
FFail 2 as FFail1		

18.8 Negative Phase Sequence (NPS) Thermal

I2therm>1 Alarm:	Disabled, Enabled
I2therm>1 Set:	0.03…0.5 In
I2therm>1 Delay:	0…100 s
I2therm>2 Trip:	Disabled, Enabled
I2therm>2 Set:	0.05…0.5 In
I2therm>2 k:	2…40.0 s
I2therm>2 kRESET:	2…40.0
I2therm>2 tMAX:	500…2000.00 s
I2therm>2 tMIN:	0.25…40 s

The P34x Negative Phase Sequence (NPS) element offers a true thermal characteristic according to the formula:

$$t = -\frac{(\text{I2>2 k Setting})}{(\text{I2>2 Current set})^2} \log_e \left(1 - \left(\frac{(\text{I2>2 Current set})}{I_2}\right)^2\right)$$

Note	All current terms are in per-unit, based on the relay rated current, *In*.

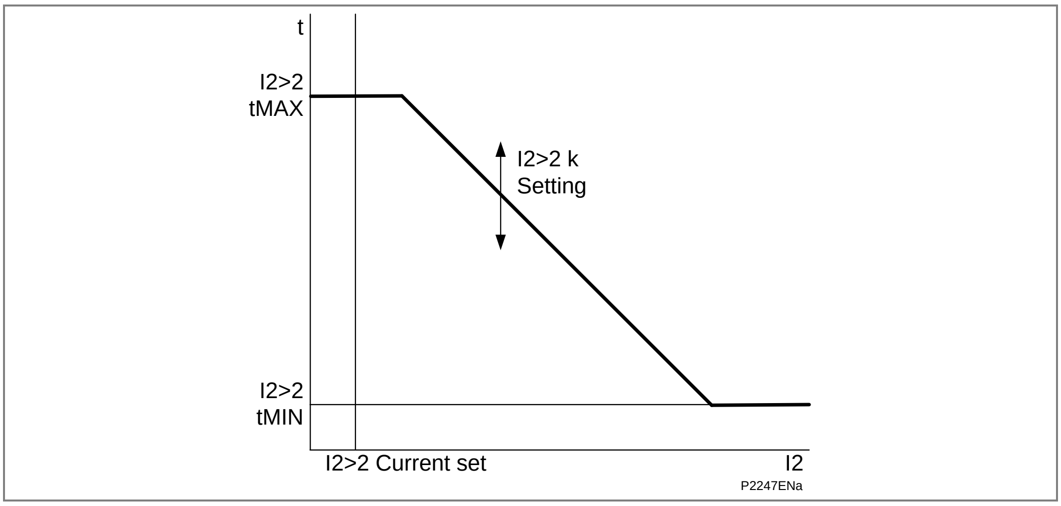

Figure 2 - Negative phase sequence thermal characteristic

18.9 System Backup

18.9.1 Voltage Dependent Overcurrent and Underimpedance

Backup Function:	Disabled or Voltage Controlled Voltage Restrained or Under Impedance
Vector Rotation:	None/Delta-Star
V Dep OC Char:	DT or IEC S Inverse or IEC V Inverse or IEC E Inverse or UK LT Inverse or UK Rectifier or RI or IEEE M Inverse or IEEE V Inverse or IEEE E Inverse or US Inverse or US ST Inverse
V Dep OC I > Set:	0.8…4In
V Dep OC T Dial:	0.01…100
V Dep OC Reset:	DT or Inverse
V Dep OC Delay:	0…100 s
V Dep OC TMS:	0.025…1.2
V Dep OC K(RI):	0.1…10
V Dep OC tRESET:	0…100 s
V Dep OC V<1/2 Set:	5…120 V (100/120 V)
V Dep OC V<1/2 Set:	20…480 V (380/480 V)
V Dep OC k Set:	0.1…1
Z<1 Setting:	2…120.0 Ω (100/120 V, 1A) 0.4…24.0 Ω (100/120 V, 5A) 8…480 Ω (380/440 V, 1A) 1.60…96.0 Ω (380/440 V, 5A)
Z<1 Time Delay:	0.00…100.0 s
Z<1 tRESET:	0…100 s
Z<2 as Z<1	

18.9.2 IDMT Characteristics

Inverse Time (IDMT) Characteristic

IDMT characteristics are selectable from a choice of four IEC/UK and five IEEE/US curves as shown in the table below.

The IEC/UK IDMT curves conform to the following formula:

$$t = T \times \left(\frac{K}{(I/Is)^{\alpha} - 1} + L \right)$$

The IEEE/US IDMT curves conform to the following formula:

$$t = TD \times \left(\frac{K}{(I/Is)^{\alpha} - 1} + L \right)$$

Where:

	t	= Operation time
	K	= Constant
	I	= Measured current
	Is	= Current threshold setting
	α	= Constant
	L	= ANSI/IEEE constant (zero for IEC/UK curves)
	T	= Time Multiplier Setting for IEC/UK curves
	TD	= Time Dial Setting for IEEE/US curves

IDMT Characteristics

IDMT Curve description	Standard	K 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-C08	5.95	2	0.18
Short Time Inverse	US-C02	0.16758	0.02	0.11858

Table 4 - IDMT characteristics

The IEC extremely inverse curve becomes definite time at currents greater than 20 x setting. The IEC standard, very and long time inverse curves become definite time at currents greater than 30 x setting.

The definite time part of the IEC inverse time characteristics at currents greater than 20x and 30x setting are only relevant for currents in the operating range of the relay.

The operating range of the P342/P343/P344/P345 current inputs is 0 - 16 In for the standard current inputs and is 0 - 2 In for the sensitive current input.

For all IEC/UK curves, the reset characteristic is definite time only.

For all IEEE/US curves, the reset characteristic can be selected as either inverse curve or definite time.

The inverse reset characteristics are dependent upon the selected IEEE/US IDMT curve as shown in the table below.

All inverse reset curves conform to the following formula:

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

Where:

TD = Time dial setting for IEEE and user programmable 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

The RI curve (electromechanical) has been included in the first stage characteristic setting options for Phase Overcurrent and Earth Fault protections. The curve is represented by the following equation:

Where K is adjustable from 0.1 to 10 in steps of 0.05, and M = I / Is

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

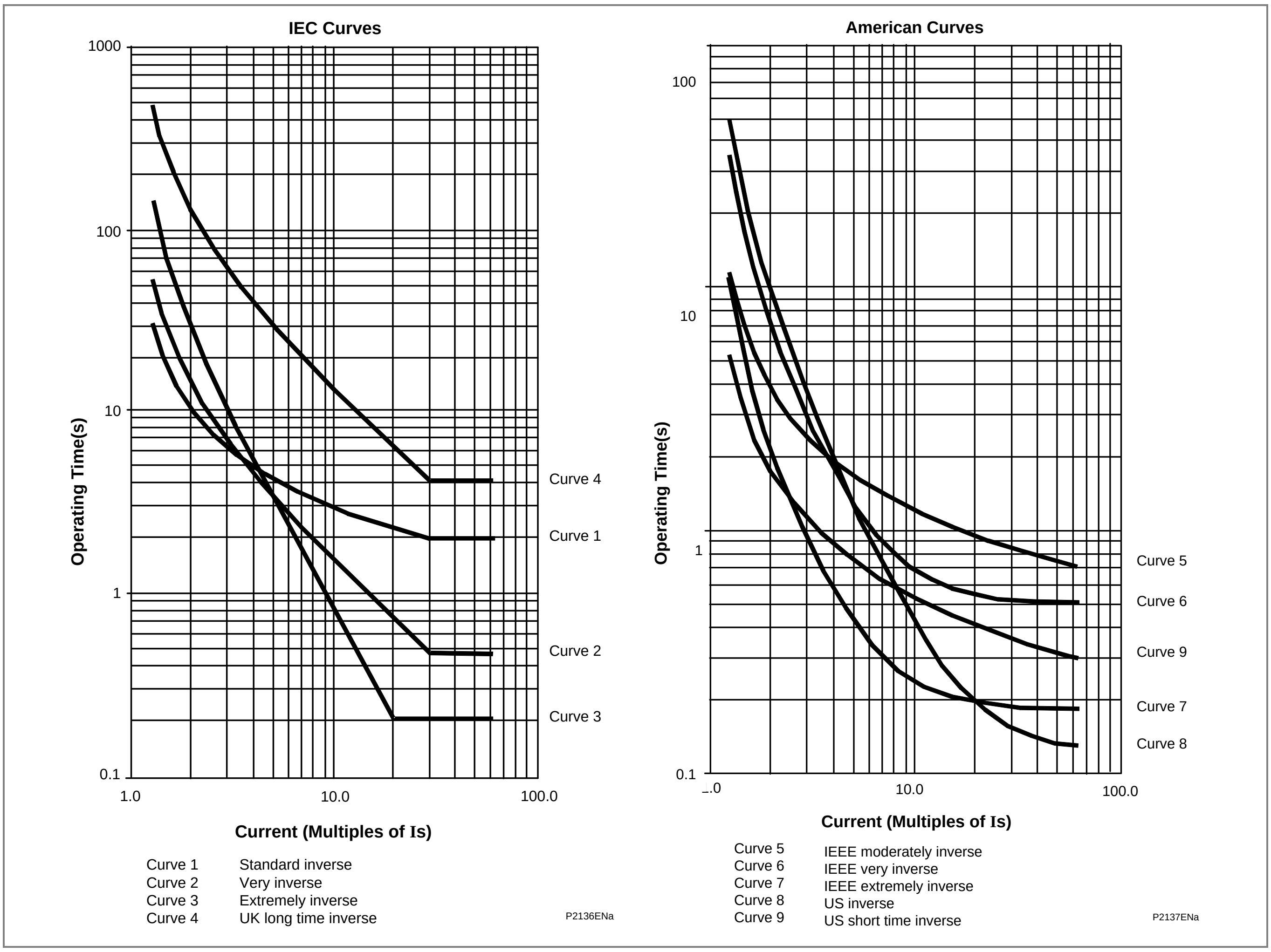

Figure 3 - Current/Time Curves

18.10 Phase Overcurrent (Overcurrent)

I> CT Source:	IA-1 IB-1 IC-1/IA-2 IB-2 IC-2
I>1 Function:	Disabled or DT or IEC S Inverse IEC V Inverse or IEC E Inverse or UK LT Inverse UK Rectifier or RI or IEEE M Inverse IEEE V Inverse or IEEE E Inverse or US Inverse US ST Inverse
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 Reset Char:	DT/Inverse
I>1 tRESET:	0.00…100.00 s
I>2 as I>1	

I>3 Status: Disabled, Enabled
I>3 Direction: Non-Directional or Directional Fwd or Directional Rev
I>3 Current Set: 0.08…10.00 In
I>3 Time Delay: 0.00…100.00 s
I>4 as I>3
I> Char Angle: -95…+95o
I >Function Link: Bit 0 = VTS Blocks I>1 or Bit 1 = VTS Blocks I>2
Bit 2 = VTS Blocks I>3 or Bit 3 = VTS Blocks I>4
Bit 4, 5, 6 & 7 are not used

Binary function link string, selecting which overcurrent elements (stages 1 to 4) will be blocked if VTS detection of fuse failure occurs.

18.11 Negative Phase Sequence (NPS) Overcurrent

I2> CT Source: IA-1 IB-1 IC-1/IA-2 IB-2 IC-2
I2>1 Status: Disabled, Enabled
I2>1 Direction: Non-Directional
Directional Fwd
Directional Rev
I2> Current Set: 0.08…4.00 In
I2> Time Delay: 0.00…100.00 s
I2>2/3/4 as for I2>1
I2> VTS Block: Bit 0 = VTS Blocks I2>1
Bit 1 = VTS Blocks I2>2
Bit 2 = VTS Blocks I2>3
Bit 3 = VTS Blocks I2>4
Bits 4, 5, 6 & 7 are not used

Binary function link string, selecting which NPS overcurrent elements (stages 1 to 4) will be blocked if VTS detection of fuse failure occurs.

I2> V2pol Set: 0.5…25.0 (100 V 120 V)
2…100 V(380/480 V)
I2> Char Angle: -95º…+95 º

18.12 Thermal Overload

Gen Thermal: Sub Heading
Thermal status: Disabled, Enabled
Thermal I>: 0.50…2.50 In
Thermal Alarm: 20..100%
T-heating: 1…200 minutes
T-cooling: 1…200 minutes
M Factor: 0…10

The thermal time characteristic is given by:

$t = \tau \log e (Ieq^2 - IP^2)/(I_{eq}^2 - (\text{Thermal } I>)^2)$

$t = \tau. \log e (K^2 - A^2/(K^2-1))$

Where:
K = I_{eq}/Thermal I>
A = I_P /Thermal I>
t = Time to trip, following application of the overload current, I
τ = Heating time constant of the protected plant
I_{eq} = Equivalent current
Thermal I> = Relay setting current
I_P = Steady state pre-load current before application of the overload
$I_{eq} = \sqrt{(I_1^2 + MI_2^2)}$
I1 = Positive sequence current
I2 = Negative sequence current
M = A user settable constant proportional to the thermal capacity of the machine

Xformer Thermal:	Sub Heading
Thermal status:	Disabled, Enabled
Mon't Winding:	HV/LV/ Biased Current
Ambient T:	RTD1-10/CLIO1-4/AVERAGE
Amb CLIO Type:	0-1 / 0-10 / 0-20 / 4-20 mA
Amb CLIO Min:	-9999.0 to +9999.0
Amb CLIO Max:	-9999.0 to +9999.0
Average Amb T:	-25.0 to +75.0 Cel
Top Oil T:	RTD1-10/CIO1-4/CALCULATED
Top Oil CLIO Typ:	0-1 / 0-10 / 0-20 / 4-20 mA
Top Oil CLIO Min:	-9999.0 to +9999.0
Top Oil CLIO Max:	-9999.0 to +9999.0
IB:	0.1 to 4.0 PU
Rated NoLoadLoss:	0.1 to 100.0
Hot Spot Overtop:	0.1 to 200.0 Cel
Top Oil Overamb:	0.1 to 200.0 Cel
Cooling Mode:	Natural/Forced Air/ Forced Oil/ Forced Air & Oil/Select via PSL/ Natural Cooling/Forced Air Cool/Forced Oil Cool/Frced AirOil Cool:
Winding exp m:	0.01 to 2.00
Oil exp n:	0.01 to 2.00
Hot spot rise co:	0.01 to 20.00 min
Top oil rise co:	1 to 1000 min
TOL Status:	Disabled, Enabled
Hot Spot>1 to 3 Set:	1.0 to 300.0 Cel
tHot Spot>1 to 3 Set:	0 to 60 k min
Top Oil>1 to 3 Set:	1.0 to 300.0 Cel
tTop Oil>1 to 3 Set:	0 to 60 k min
tPre-trip Set:	0 to 60k min
LOL Status:	Disabled, Enabled
Life Hours at HS:	1 to 300,000 hr
Designed HS temp:	1 to 200.0 Cel
Constant B Set:	1 to 100,000
FAA> Set:	0.10 to 30.00 min
tFAA> Set:	0 to 60 k min
LOL>1 Set:	1 to 300,000 hr
tLOL> Set:	10 to 60 k min
Reset Life Hours:	0 to 300,000 hr

2-Stage Non-Directional Earth Fault

IN>1 Function:	Disabled or DT or IEC S Inverse IEC V Inverse or IEC E Inverse or UK LT Inverse RI or IEEE M Inverse or IEEE V Inverse IEEE E Inverse or US Inverse or US ST Inverse or IDG
IN>1 Current:	0.02…4 In
IN>1 IDG Is:	1…4 In
IN>1 Time Delay:	0.00…200.0 s
IN>1 TMS:	0.025…1.200
IN>1 Time Dial:	0.01…100.00
IN>1 K(RI):	0.1…10.00
IN>1 IDG Time:	1…2.00
IN>1 Reset Char:	DT, Inverse
IN>1 tRESET:	0.00…100.00 s
IN>2 Function:	Disabled, DT
IN>2 Current Set:	0.02…10.00 In
IN>2 Time Delay:	0.00…200.00 s

The IDG curve is commonly used for time delayed earth fault protection in the Swedish market. This curve is available in stage 1 of the Earth Fault protection.

The IDG curve is represented by the following equation:

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

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.

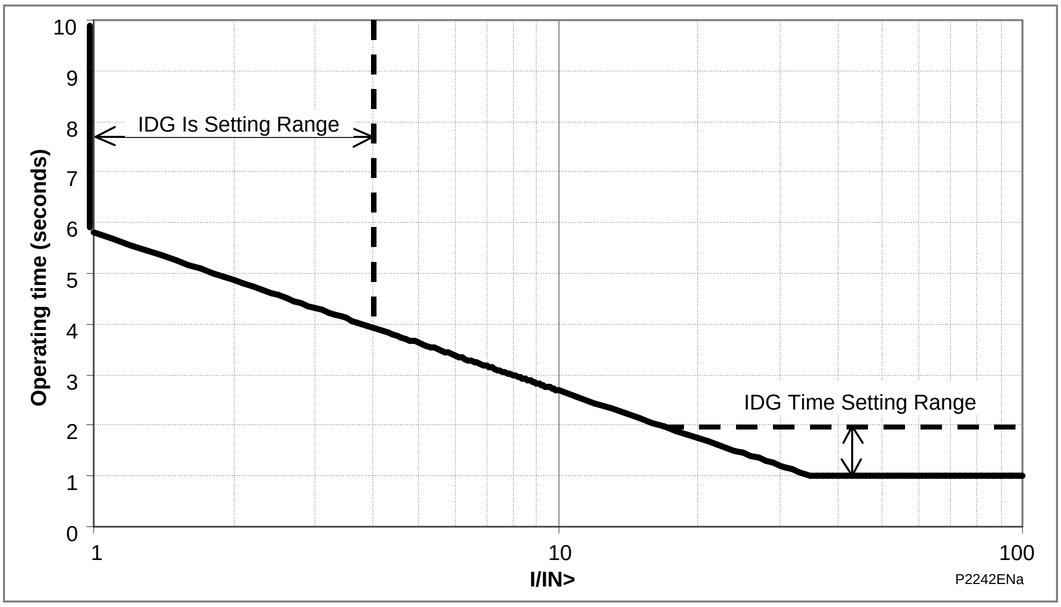

Figure 4 - IDG Characteristic

18.13 Rotor EF

Injection Freq:	0.25/0.5/1 Hz
CL I/P Select:	Current Loop CL1/2/3/4
64R< 1 Alarm:	Disabled, Enabled
64R<1 Alm Set:	1000…80000 Ω
64R<1 Alm Dly:	0.0…600.0 s
64R<2 Trip Set:	1000…80000 Ω
64R<2 Trip Dly:	0.0…600.0 s
R Compensation:	-1000…1000 Ω

18.14 SEF/REF Prot'n

SEF/REF Options:	SEF or SEF Cos (PHI) or SEF Sin (PHI) Wattmetric or Hi Z REF or Lo Z REF Lo Z REF + SEF or Lo Z REF + Watt
ISEF>1 Function:	Disabled or DT
ISEF>1 Directional:	Non-Directional or Directional Fwd or Directional Rev
ISEF>1 Current:	0.0050…0.1000 In A
ISEF>1 Delay:	0.00…200.00 s
ISEF> Func Link:	Bit 0 – Block
ISEF> from VTS	
ISEF > Char Angle:	-95º…95 º
ISEF > VNpol Input:	Measured/Derived
ISEF > Vnpol Set:	0.5…80.0 V (100/120 V) 2…320.0 V (380/480 V)

18.15 Wattmetric SEF

WATTMETRIC SEF:	
PN> Setting:	0.00…20.00 In W (100/120 V) 0.00…80.00 In W (380/480 V)

18.16 Restricted Earth-Fault (Low Impedance)

IREF> CT Source:	IA-1 IB-1 IC-1/IA-2 IB-2 IC-2
IREF > K1:	0 …20%
IREF > K2:	0 …150%
IREF > Is1:	0.05…1.00 In
IREF > Is2:	0.1…1.50 In

18.17 Restricted Earth-Fault (High Impedance)

IREF > K1:	0.05…1.00 In

18.18 Residual O/V NVD

VN>1 Status:	Disabled, Enabled
VN>1 Input:	Derived
VN> 1 Function:	Disabled or DT or IDMT
VN> 1 Voltage Set:	1…80 V (100/120 V) 4…320 V (380/480 V)
VN> 1 Time Delay:	0.00…100.00 s
VN>1 TMS:	0.5…100.0
VN> 1 tRESET:	0.00…100.00
VN>2 as VN>1	
VN>3/4 as VN>1 except	
VN>3/4 Input:	VN1
VN>5/6 as VN>1 except	
VN>5/6 Input:	VN2 (P344/P345)

18.19 100% Stator Earth Fault (3rd Harmonic)

100% St EF Status:	Disabled, VN3H< Enabled, VN3H> Enabled	
100% St EF VN3H<:	0.3…20.0 V	
VN3H< Delay:	0.00…100.00s	
V < Inhibit Set:	30…120 V	(100/120 V)
	120…480 V	(380/440 V)
P < Inhibit:	Disabled, Enabled	
P < Inhibit Set:	4…200.0 In W	(100/120 V)
	16…800.In W	(380/480 V)
Q < Inhibit:	Disabled, Enabled	
Q < Inhibit: Set:	4…200.0 In W	(100/120 V)
	16…800 In W	(380/480 V)
S < Inhibit:	Disabled, Enabled	
S < Inhibit Set:	4…200.0 In W	(100/120 V)
100% St EF VN3H>:	0.3…20.0 V	(100/120 V)
	1.20…80.0 V	(380/480 V)
VN3H> Delay:	0.00…100.00 s	

18.20 100% Stator Earth Fault (Low Frequency Injection)

64S LF Injection:	Disabled, Enabled
64S R Factor:	0.01…200
64S R<1 Alarm:	Disabled, Enabled
64S R<1 Alm Set:	10…700 Ω
64S R<1 Alm Delay:	0.00…100.0 s
64S R<2 Trip:	Disabled, Enabled
64S R<2 Trip Set:	10…700 Ω
64S R<2 Trip Dly:	0.00…100.0 s
64S Angle Comp:	-60º…60 º
64S Series R:	0…700 Ω
64S Series X:	0…700 Ω
64S Parallel G:	0.00…0.1 S
64S Overcurrent:	Disabled, Enabled
64S I>1 TripSet:	0.02…1.5A
64S I>1 TripDly:	0.00…100.0 s
64S Supervision:	Disabled, Enabled
64S V<1 Set:	0.3…25 V
64S I<1 Set:	0.005…0.04A
64S Supern’n Dly:	0.00…100.0 s

18.21 Volts/Hz

V/Hz Alarm Status:	Disabled, Enabled
V/Hz Alarm Set:	1.50…3.500 V/Hz (100/120 V) 6…14.00 V/Hz (380/480 V)
V/Hz Alarm Delay:	0.00…100.0 s
V/Hz>1 Status:	Disabled/Enabled
V/Hz Trip Func:	DT or IDMT
V/Hz> 1 Trip Set:	1.500…3.500 V/Hz (100/120 V) 6…14.00 V/Hz (380/480 V)
V/Hz> 1Trip TMS:	0.01…12.00
V/Hz> 1 Trip Delay:	.0.00…600.0 s
V/Hz>2 Status:	Disabled, Enabled
V/Hz>2 Trip Set:	1.500…3.500 V/Hz (100/120 V) 6…14.00 V/Hz (380/480 V)
V/Hz>2 Trip Delay: .	0.00…600.0 s

V/Hz>3/4 as V/Hz>2

The inverse time characteristic is given by

$$t = \frac{TMS}{(M - 1)^2}$$

Where:

$$M = \frac{V/f}{(\text{V/f Trip Setting})}$$

V = Measured voltage

F = Measured frequency

18.22 DF/DT

Operating Mode:	Fixed Window/Rolling Window
df/dt Avg Cycles:	2…12
df/dt Iterations:	1…4
df/dt>1 Status:	Disabled, Enabled
df/dt>1 Setting:	0.10…10.00 Hz/S
df/dt>1 Dir'n:	Negative/Positive/Both
df/dt>1 Time:	0.00…100.00 s
df/dt>1 f L/H:	Disabled, Enabled
df/dt>1 f Low:	45.00…65.00 Hz
df/dt>1 f High:	45.00…65.00 Hz
df/dt>2/3/4 Status:	Disabled, Enabled
df/dt>2/3/4 Setting:	0.10…10.00Hz/S
df/dt>2/3/4 Dir'n:	Negative/Positive/Both
df/dt>2/3/4 Time:	0.00…100.00 s

18.23 Dead Machine

DM CT Source:	IA-1 IB-1 IC-1/IA-2 IB-2 IC-2
Dead Mach Status:	Disabled, Enabled
Dead Mach I>:	0.08…4.00 In A
Dead Mach V <:	10…120 V (100/120 V) 40…480 V (380/480 V)
Dead Mach tPU:	0.0…10.0 s
Dead Mach tDO:	0.0…10.0 s

18.24 Voltage Protection

18.24.1 Undervoltage

V< Measur’t Mode:	Phase-Phase or Phase-Neutral
V< Operate Mode:	Any Phase or Three Phase
V< 1 Function:	Disabled or DT or IDMT
V<1 Voltage Set:	10…120 V (100/120 V) or 40…480 V (380/480 V)
V<1 Time Delay:	0.00…100.00 s
V<1 TMS:	0.05…100.0
V<1 Poledead Inh:	Disabled, Enabled
V<2 Function:	Disabled or DT
V<2 Status:	Disabled, Enabled
V<2 Voltage Set:	10…120 V (100/120 V) or 40…480 V (380/480 V)
V<2 Time Delay:	0.00…100.00 s
V<2 Poledead Inh:	Disabled, Enabled

The inverse characteristic is given by:

$$t = \frac{K}{(1 - M)}$$

Where:
K = Time multiplier setting
t = Operating time in seconds
M = Applied input voltage/ undervoltage setting

18.24.2 Overvoltage

V> Measur’t Mode:	Phase-Phase or Phase-Neutral
V> Operate Mode:	Any Phase or Three Phase
V> 1 Function:	Disabled or DT or IDMT
V>1 Voltage Set:	60…185 V (100/120 V) 240…740 V (380/480 V)
V>1 Time Delay:	0.00…100.00 s
V>1 TMS:	0.05…100.0
V>2 Status:	Disabled or Enabled
V>2 Voltage Set:	60…185 V (100/120 V) 240…740 V (380/480 V)
V>2 Time Delay:	0.00…100.00 s

The inverse characteristic is given by:

$$t = \frac{K}{(M - 1)}$$

Where:
K = Time multiplier setting
t = Operating time in seconds
M = Applied input voltage/overvoltage setting

18.24.3 NPS Overvoltage

V2>1 status:	Disabled, Enabled
V2>1 Voltage Set:	1…150 V (100/120 V) 4…600 V (380/480 V)
V2>1 Time Delay:	0.00…100.00 s

18.25 Frequency Protection

18.25.1 Underfrequency

F<1 Status:	Disabled/Enabled
F<1 Setting:	45.00…65.00 Hz
F<1 Time Delay:	0.1…100.0 s
F<2/3/4 as F<1	
F< Function Link:	Bit 0 - Enable Block F<1 during poledead Bit 1 - Enable Block F<2 during poledead Bit 2 - Enable Block F<3 during poledead Bit 3 - Enable Block F<4 during poledead

18.25.2 Overfrequency

F>1 Status:	Disabled/Enabled
F>1 Setting:	45.00…68.00 Hz
F>1 Time Delay:	0.1…100.0 s
F>2 Status (up to):	
F>2 Time Delay	

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

18.25.3 Generator Turbine Abnormal Frequency

Turbine F Status:	Disabled, Enabled
Band 1 Status:	Disabled, Enabled
Band 1 Freq Low:	20.00…70.00 Hz
Band 1 Freq High:	20.00…70.00 Hz
Band 1 Duration:	0.00…3600000.00 s
Band 1 Dead Time:	0.00…200.00 s
Band 2/3/4/5/6 as Band 1	

18.26 RTD Protection

Select RTD: Bit 0 - Select RTD 1, Bit 1 - Select RTD 2 to Bit 9 - Select RTD 10
Binary function link string, selecting which RTDs (1 - 10) are enabled.

RTD 1 Alarm Set:	0°C to 200°C
RTD 1 Alarm Dly:	0 s to 100 s
RTD 1 Trip Set:	0°C to 200°C
RTD 1 Trip Dly:	0 s to 100 s

RTD2/3/4/5/6/7/8/9/10 the same as RTD1

18.27 Supervisory Functions

18.27.1 Voltage Transformer Supervison

VTS Status:	Blocking/Indication	
VTS Reset Mode:	Manual/Auto	
VTS Time Delay:	1.0…10.0 s	
VTS I> Inhibit:	0.08 In…32.0 In	
VTS I2> Inhibit:	0.05 In…0.50 In	
Negative phase sequence voltage (V2):		10 V (100/120 V) 40 V (380/480 V)
Phase overvoltage:	Pick-up	30 V,
	Drop-off	10 V (100/120 V)
	Pick-up	120 V,
	Drop-off	40 V (380/480 V)
Superimposed Current:	0.1 In	

18.27.2 Current Transformer Supervision

CTS 1 Status:	Disabled, Enabled	
CTS 1 VN Input:	Measured/Derived	
CTS 1 VN< Inhibit:	0.5…22 V	(100/120 V)
	2…88 V	(380/480 V)
CTS 1 IN> Set:	0.08…4 In	
CTS 2 as CTS1		

18.27.3 DIFF Current Transformer Supervision

DIFF CTS:	Disabled, Enabled
Diff CTS Mode:	Restrain/Indication
CTS Time Delay:	0.0 to 10.0 s
CTS I1:	5 to 100% in 1% steps
CTS I2/I1>1:	5 to 100%
CTS I2/I1>2:	5 to 100%

18.28 Through Fault

Through Fault:	Disabled, Enabled
Monitored Input:	HV / LV
TF I> Trigger:	0.08 to 16.00 In
TF I2t> Alarm:	0 to 500 000 A2 s

18.29 System Checks

18.29.1 Voltage Monitors

Over/Live/Diff Voltage

Gen Overvoltage:	1.0…185.0 V (100/110V)	4…740 V (380/440 V)
CS Overvoltage:	60.0…185.0 V (100/110 V)	240…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 or Undervoltage or Overvoltage or Differential or UV & OV or UV & DiffV or OV & DiffV or UV, OV & DiffV	

Bus Under/Dead Voltage

CS Undervoltage:	10.0…132.0 V (100/110 V)	4…528 V (380/440 V)
Live/Dead Voltage:	1.0…132.0 V (100/110 V)	4…528 V (380/440 V)
Gen Undervoltage:	1.0…132.0 V (100/110 V)	4…528 V (380/440 V)

Generator Underfrequency

Gen Under Freq: 45.00...65.00 Hz

Generator Overfrequency

Gen Over Freq: 45.00...65.00 Hz

18.29.2 Check Sync

CS1 Status:	Disabled, Enabled		
CS1 Phase Angle:	5…90º		
CS1 Slip Control:	None or Timer or Frequency or Both		
CS1 Slip Freq.:	0.01…1.00 Hz		
CS1 Slip Timer:	0.00…99.00 s		
CS2 Status:	Disabled, Enabled		
CS2 Phase Angle:	5…90º		
CS2 Slip Control:	None or	Timer or	Frequency or
	Timer + Freq or		Freq + CB Comp
CS2 Slip Freq.:	0.01…1.00 Hz		
CS2 Slip Timer:	0.00…99.00 s		

18.29.3 System Split

SS Status:	Disabled, Enabled
SS Phase Angle:	90…175o
SS Under V Block:	Disabled, Enabled
SS Undervoltage:	10.0…132.0 V (100/110 V) or 40…528 V (380/440 V)
SS Timer:	0.00…99.00 s
CB Close Time:	0.000…0.500 s

18.30 Plant Supervision

18.30.1 CB State Monitoring Control and Condition Monitoring

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

18.31 Current Loop Input

CLIO1 Input 1:	Disabled/Enabled
CLI1 Input Type:	0 – 1 mA 0 – 10 mA 0 – 20 mA 4 – 20 mA
CLI1 Input Label:	16 characters (CLIO input 1)
CLI1 Minimum:	-9999…+9999
CLI1 Maximum:	-9999…+9999
CLI1 Alarm:	Disabled/Enabled
CLI1 Alarm Fn:	Over/Under
CLI1 Alarm Set:	CLI1 min to CLI1 max
CLI1 Alarm Delay:	0.0 to 100.0 s
CLI1 Trip:	Disabled/Enabled
CLI1 Trip Fn:	CLI1 min to CLI1 max
CLI1 Trip Delay:	0.0 to 100.0 s
CLI1 I< Alarm (4 to 20 mA input only):	Disabled/Enabled
CLI1 I< Alm Set (4 to 20 mA input only):	0.0 to 4.0 mA

CLI2/3/4 the same as CLI1

18.32 Current Loop Output

CLO1 Output 1:	Disabled/Enabled
CLO1 Output Type:	0 – 1 mA 0 – 10 mA 0 – 20 mA 4 – 20 mA
CLO1 Set Values:	Primary/Secondary
CLO1 Parameter:	As shown below*
CLO1 Min:	Range, step size and unit corresponds to the selected parameter
CLO1 Max:	Same as CLO1 Min

CLO2/3/4 the same as CLO1

Current Loop Output Parameters:

Current Magnitude:	IA Magnitude / IB Magnitude / IC Magnitude / IN Measured Mag (P342) / IN-1 Measure Mag (P343/P344/P345/P346 / IN-2 Measure Mag (P343/P344/P345/P346 / 0.00…16.0A
I Sen Mag:	0.00…2.0A
Phase Sequence Components:	I1 Magnitude / I2 Magnitude / I0 Magnitude 0.00…16.0A
Phase Currents	IA RMS* / IB RMS* / IC RMS* 0.00…16.0A
P-P Voltage Magnitude	VAB Magnitude / VBC Magnitude / VCA Magnitude 0.0…200.0 V
P-N Voltage Magnitude	VAN Magnitude / VBN Magnitude / VCN Magnitude 0.0…200.0 V
Neutral Voltage Magnitude	VN1 Measured Mag / VN Derived Mag / VN2 Measured Mag (P344/P345) 0.0…200.0 V
VN 3rd Harmonic	0.0…200.0 V (P343/P344/P345)
Phase Sequence Voltage Components	V1 Magnitude / V2 Magnitude / V0 Magnitude 0.0…200.0 V
RMS Phase Voltages	VAN RMS* / VBN RMS* / VCN RMS* 0.0…200.0 V
Frequency	0.00…70.0 Hz
3 Phase Watts*	-6000 W…6000 W
3 Phase Vars*	-6000 Var…6000 Var
3 Phase VA*	0…6000 VA
3Ph Power Factor*	-1…1
Single Phase Active Power	A Phase Watts* / B Phase Watts* / C Phase Watts* -2000W…2000 W
Single Phase Reactive Power	A Phase Vars* / B Phase Vars* / C Phase Vars* -2000Var…2000 Var
Single Phase Apparent Power	A Phase VA* / B Phase VA* / C Phase VA* 0…2000 VA
Single Phase Power Factor	Aph Power Factor* / BPh Power Factor* / CPh Power Factor* -1…1
3 Phase Current Demands	IA Fixed/Roll/Peak Demand* / IB Fixed/Roll/Peak Demand* / IC Fixed/Roll/Peak Demand* 0.00…16.0A
3ph Active Power Demands	3Ph W Fix/Roll/Peak Demand* / -6000 W…6000 W
3ph Reactive Power Demands	3Ph Vars Fix/Roll/Peak Dem* / -6000 Var…6000 Var
NPS Thermal	0.00…200.0%
Thermal Overload	0.00…200.0%
RTD 1-10*	-40ºC…300.0ºC
CL Input 1-4	-9999…9999.0
Volts/Hz	0…20 V/Hz

Note 1	*Measurements marked with an asterisk, the internal refresh rate is nominally 1 s, others are 0.5 power system cycles or less.*
Note 2	*The polarity of Watts, Var and power factor is affected by the measurements Mode setting.*
Note 3	*These settings are for nominal 1A and 100/120 V versions only. For other versions they need to be multiplied accordingly.*

19 MEASUREMENTS LIST

19.1 Measurements 1, 2, 3 and 4

Measurements 1	Measurements 2	Measurements 3	Measurements 4
Iφ Magnitude	φ Phase Watts	Iφ Magnitude	Hot Spot T
Iφ Phase Angle: Per phase (φ = A/A-1, B/B-1, C/C-1) current measurements	φ Phase VArs	Iφ Phase Angle: Per phase (φ = A-2, B-2, C-2) current measurements	Top Oil T
IN Measured Mag	φ Phase VA: All phase segregated power measurements, real, reactive and apparent (φ = A, B, C).	IA Differential	Reset Thermal: No/Yes
IN Measured Angle	3 Phase Watts	IB Differential	Ambient T
IN Derived Mag	3 Phase VArs	IC Differential	TOL Pretrip left
IN Derived Angle	3 Phase VA	IA Bias	LOL status
ISen Mag	NPS Power S2	IB Bias	Reset LOL
ISen Angle	3Ph Power Factor	IC Bias	Rate of LOL
I1 Magnitude	φPh Power Factor: Independent power factor measurements for all three phases (φ = A, B, C).	IREF Diff	LOL Ageing Fact
I2 Magnitude	3Ph WHours Fwd	IREF Bias	Lres at Design T
I0 Magnitude	3Ph WHours Rev	VN 3rd harmonic	FAA,m
Iφ RMS: Per phase (φ = A, B, C) RMS current measurements	3Ph VArHours Fwd	NPS Thermal	Lres at FAA,m
IN -2 Derived	3Ph VArHours Rev	Reset NPS Thermal: No/Yes	
Vφ-φ Magnitude	3Ph W Fix Demand	RTD1-10	
Vφ-φ Phase Angle	3Ph VArs Fix Dem	RTD Open Cct	
Vφ Magnitude	Iφ Fixed Demand: Maximum demand currents measured on a per phase basis (φ = A, B, C).	RTD Short Cct	
Vφ Phase Angle: All phase-phase and phase-neutral voltages (φ = A, B, C).	3Ph W Roll Dem	RTD Data Error	
VN/VN1 Measured Mag	3Ph VArs Roll Dem	Reset RTD1-10: No/Yes	
VN/VN1 Measured Ang	Iφ Roll Demand: Maximum demand currents measured on a per phase basis (φ = A, B, C).	ϕ Ph Sen Watts (ϕ= A, B or C if setting Phase Select = A, B or C)	
VN Derived Mag	3Ph W Peak Dem	ϕ Ph Sen VArs (ϕ= A, B or C if setting Phase Select = A, B or C)	
V1 Magnitude	3Ph VAr Peak Dem	ϕ Phase Power Angle (ϕ= A, B or C if setting Phase Select = A, B or C)	
V2 Magnitude	Iφ Peak Demand: Maximum demand currents measured on a per phase basis (φ = A, B, C).	Thermal Overload	

Measurements 1	Measurements 2	Measurements 3	Measurements 4
V0 Magnitude	Reset Demand: No/Yes	Reset Thermal O/L: No/Yes	
Vφ RMS: All phase-neutral voltages (φ = A, B, C).	CT2 NPS Power S2	CLIO Input 1/2/3/4	
Frequency		F Band1-6 Time(s)	
I1 Magnitude		Reset Freq Band1-6: No/Yes	
I1 Angle		Reset Freq Bands: No/Yes	
I2 Magnitude		df/dt	
I2 Angle		Volts/Hz	
I0 Magnitude		64S Magnitude	
I0 Angle		64S I Magnitude	
V1 Magnitude		64S I Angle	
V1 Angle		64S R secondary	
V2 Magnitude		64S R primary	
V2 Angle		64R CL Input	
V0 Magnitude		64R R Fault	
V0 Angle		IA/IB/IC Diff PU	
VN2 Measured Mag		IA/IB/IC Bias PU	
VN2 Measured Ang		IA/IB/IC Diff 2H	
C/S Voltage Mag		IA/IB/IC Diff 5H	
C/S Voltage Ang		CT2 I1 Mag	
Gen-Bus Volt		CT2 I1 Angle	
Gen-Bus Angle		CT2 I2 Mag	
Slip Frequency		CT2 I2 Angle	
C/S Frequency		CT2 I0 Mag	
		CT2 I0 Angle	
		CT1 I2/I1	
		CT2 I2/I1	

19.2 Circuit Breaker Monitoring Statistics

CB Operations

Total Iφ Broken   Cumulative breaker interruption duty on a per phase basis (φ = A, B, C).

CB Operate Time

Reset CB Data: No/Yes

20 LABELS

20.1 Opto Input Labels

Opto Input 1 to 24: Input L1 to Input L24
User-defined text string to describe the function of the particular opto input.

20.2 Output Labels

Relay 1 to Relay 46:
User-defined text string to describe the function of the particular relay output contact.

20.3 RTD Labels

RTD 1-10: RTD1 to RTD10
User-defined text string to describe the function of the particular RTD.

20.4 Control Input Labels

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

20.5 Virtual Input Labels

Virtual Input 1 to Virtual Input 64.
User-defined text string to describe the function of the particular virtual input.

20.6 Virtual Output Labels

Virtual Output 1 to Virtual Output 32.
User-defined text string to describe the function of the particular virtual output.

20.7 SR/MR User Alarm Labels

SR User Alarm 1 to SR User Alarm 16:
User-defined text string to describe the function of the particular self-reset user alarm.
MR User Alarm 17 to MR User Alarm 32:
User-defined text string to describe the function of the particular manual reset user alarm.

21 P391 TECHNICAL DATA

21.1 Mechanical Specifications

21.1.1 Design

Modular MiCOM Px40 platform relay, 80TE, front of panel flush mounting, or 19" rack mounted (ordering option).

21.1.2 Enclosure Protection

Enclosure Protection

Per IEC 60529: 1989:	P44y, P54x, P547 & P746
Per IEC 60529: 1992:	P14x, P24x, P34x, P44x, P445, P64x, P740, P841 & P849
IP 52 Protection (front panel) against dust and dripping water.	P14x, P24x, P34x, P44x, P44y, P445, P54x, P547, P64x, P740, P746, P841 & P849
IP 30 Protection for the rear and sides of the case against dust.	P44y, P54x, P547 & P841
IP 50 Protection for the rear and sides of the case against dust.	P14x, P24x, P34x, P44x, P445, P64x, P740, P746 & P849
IP 10 Product safety protection for the rear due to live connections on the terminal block.	P14x, P24x, P34x, P44x, P44y, P445, P54x, P547, P64x, P740, P746, P841 & P849

Per IEC 60529: 1992

Rack and Panel Mounting Options: IP 20 (Safety) Protection for the case with the terminal safety cover fitted.

Wall Mounting Option: IP 20 (Safety) Protection for the P391 unit with the terminal safety cover fitted.

21.1.3 Weight

P391 (80TE): 5kg

21.2 Terminals

21.2.1 AC 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.

21.2.2 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 $2.5mm^2$.

21.2.3 General Input/Output Terminals

For current loop outputs.
Located on general purpose (grey) blocks:
Threaded M4 terminals, for ring lug/terminal connection.

21.3 Ratings

21.3.1 Low Frequency Measuring Inputs

Nominal frequency: 0.25, 0.5, 1 Hz (settable with an internal jumper link)

21.3.2 DC Field Voltage Inputs

Regulated 48 Vdc
Current limited at 112 mA maximum output
Operating range 40 to 60 V

Regulated 48 Vdc
Current limited at 112 mA maximum output

1200 V dc maximum

21.4 Power Supply

21.4.1 Auxiliary Voltage (Vx)

60-250 V dc, or 100-230 V ac (rms) 50/60 Hz

21.4.2 Operating Range

48 to 300V (dc) or 85 to 253V (ac) (rms) 50/60Hz.
With a tolerable ac ripple of up to 12% for a dc supply, per IEC 60255-11: 1979.

21.4.3 Nominal Burden

Auxiliary Supply Input burden: 11 W or 24 VA.

21.4.4 Power Supply Interruption

As for IEC 60255-11: 1979:

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

As for IEC 61000-4-11: 2004:

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

A MiCOM E124 extends these limits. It is an auxiliary device used to provide energy to the trip coil of a circuit breaker.

21.5 Output Contacts

21.5.1 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)

Loaded contact: 10,000 operations Minimum
Unloaded contact: 10,000 operations Minimum

21.6 Environmental Conditions

21.6.1 Ambient Temperature Range

As for EN 60088-2-1: 2007: EN 60168-2-2: 2007
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)

21.6.2 Ambient Humidity Range

Per IEC 60068-2-78: 2001:
56 days at 93% relative humidity and +40°C

21.7 Type Tests

21.7.1 Insulation

Per EN / IEC 60255-27:
Insulation resistance > 100 MΩ at 500 Vdc
(Using only electronic/brushless insulation tester).

21.7.2 Creepage Distances and Clearances

Per IEC 60664-1: 2007
Pollution degree 2,
Impulse 9.6 kVp between injection resistor inputs and protective (case earth) conductor terminal.
Minimum of 10.5 mm clearance and 12 mm creepage distance.

21.7.3 High Voltage (Dielectric) Withstand

(i) Per IEC 60255-27: 2005, 2 kV rms ac, 1 minute:
Between all independent circuits.
Between independent circuits and protective (case earth) conductor terminal.
1 kV rms ac for 1 minute, across open watchdog contacts.

(ii) Per ANSI/IEEE C37.90: 2005
1 kV rms ac for 1 minute across open watchdog contacts.

(iii) Per 60664-1: 2007
5.8 kV rms 1 minute between injection resistor inputs and protective (case earth) conductor terminal.

21.7.4 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 independent circuits.
Between all independent circuits and protective (case earth) conductor terminal.
Between the terminals of independent circuits.
Normally open contacts of output relays excepted.

IEC 60664-1: 2007
Impulse 9.6 kV between injection resistor inputs and protective (case earth) conductor terminal

21.8 ElectroMagnetic Compatibility (EMC)

21.8.1 1 MHz Burst High Frequency Disturbance Test

As for EN / IEC 60255-22-1, 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).

21.8.2 100 kHz Damped Oscillatory Test

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

21.8.3 Electrical Fast Transient or Burst Requirements

Per IEC 60255-22-4: 2002 and EN 61000-4-4: 2004.
Test severity: Class III and IV:
Amplitude: 2 kV, burst frequency 5kHz (Class III),
Amplitude: 4 kV, burst frequency 2.5kHz (Class IV).
Applied directly to auxiliary supply, and applied to all other inputs.
(EIA RS232 ports excepted).
Amplitude: 4 kV, burst frequency 5kHz (Class IV).
Applied directly to auxiliary supply.

21.8.4 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.

21.8.5 Surge Immunity Test

(EIA(RS)232 ports excepted).
Per EN 61000-4-5: 2006 Level 4, EN 60255-22-5: 2002

Time to half-value:	1.2 / 50 µs,
Amplitude:	4 kV between all groups and protective (earth) conductor terminal,
Amplitude:	2 kV between terminals of each group.
Level 3:	1 kV between terminals of injection resistor inputs

21.8.6 Immunity to Radiated Electromagnetic Energy

Per IEC 60255-22-3: 2007, Class III: (EN61000-4-3: 2006, Level 3)

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

Per IEEE/ANSI C37.90.2: 2004:
80 MHz to 1000 MHz, 1 kHz 80% am and am pulsed modulated.
Field strength of 35 V/m.

21.8.7 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%.

21.8.8 Radiated Immunity from Digital Radio Telephones

EN 61000-4-3: 2002: 10 V/m, 900 MHz and 1.89 GHz.

21.8.9 Immunity to Conducted Disturbances Induced by Radio Frequency Fields

As for EN / IEC 61000-4-6, Level 3, Disturbing test voltage: 10 V.

21.8.10 Power Frequency Magnetic Field Immunity

EN 61000-4-8: 2010, Level 5:	100 A/m applied continuously, 1000 A/m applied for 3 s.
EN 61000-4-9: 1993+A1:2001, Level 5:	1000 A/m applied in all planes.

EN 61000-4-10: 1993+A1:2001, Level 5:
100 A/m applied in all planes at 100 kHz to 1 MHz with a burst duration of 2 s.

21.8.11 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).

21.8.12 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.

21.9 EU Directives

21.9.1 EMC Compliance

2004/108/EC:
Compliance to the European Commission Directive on EMC is demonstrated using a Technical File. Product Specific Standards were used to establish conformity:
EN 50263: 2000

21.9.2 Product Safety

2006/95/EC:
Compliance to the European Commission Low Voltage Directive. Compliance is demonstrated by reference to generic safety standards:
EN60255-27: 2005 (incorporating corrigendum March 2007)

21.10 Mechanical Robustness

21.10.1 Vibration Test

Per EN / IEC 60255-21-1	Response Class 2 Endurance Class 2

21.10.2 Shock and Bump

Per EN / IEC 60255-21-2	Shock response Class 2 Shock withstand Class 1 Bump Class 1

21.10.3 Seismic Test

Per EN / IEC 60255-21-3:	Class 2

Notes:

GETTING STARTED

CHAPTER 3

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

CONTENTS

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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/5L M/L11 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 cover:

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.

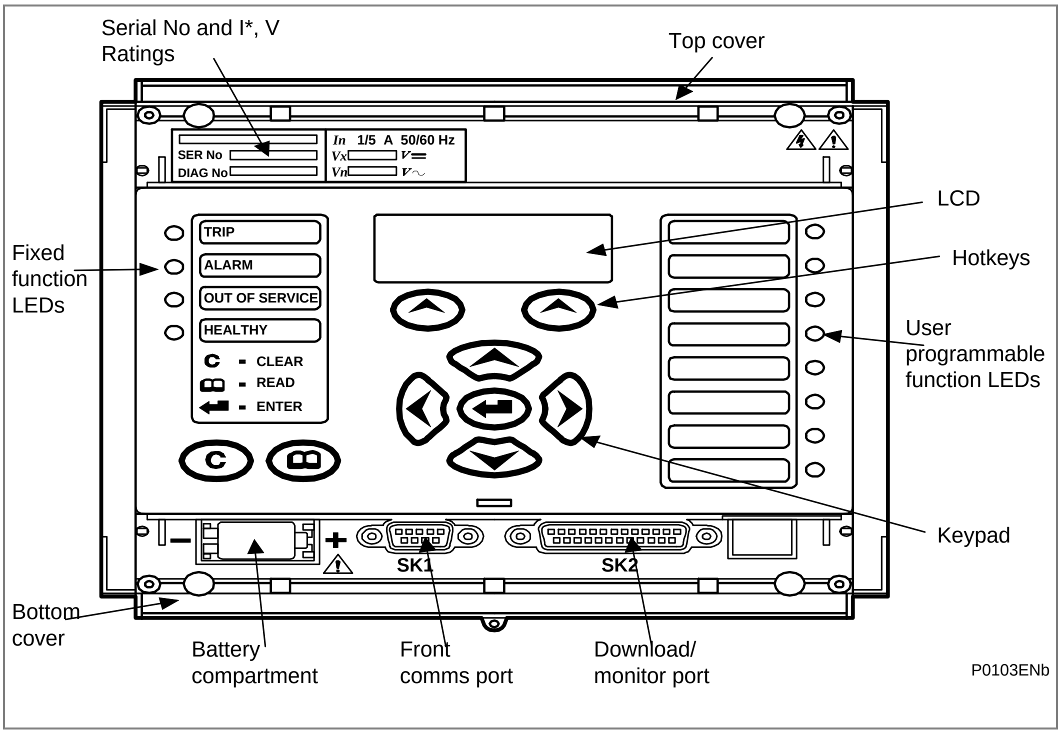

Figure 1 - Relay front view (P342) (40TE case)

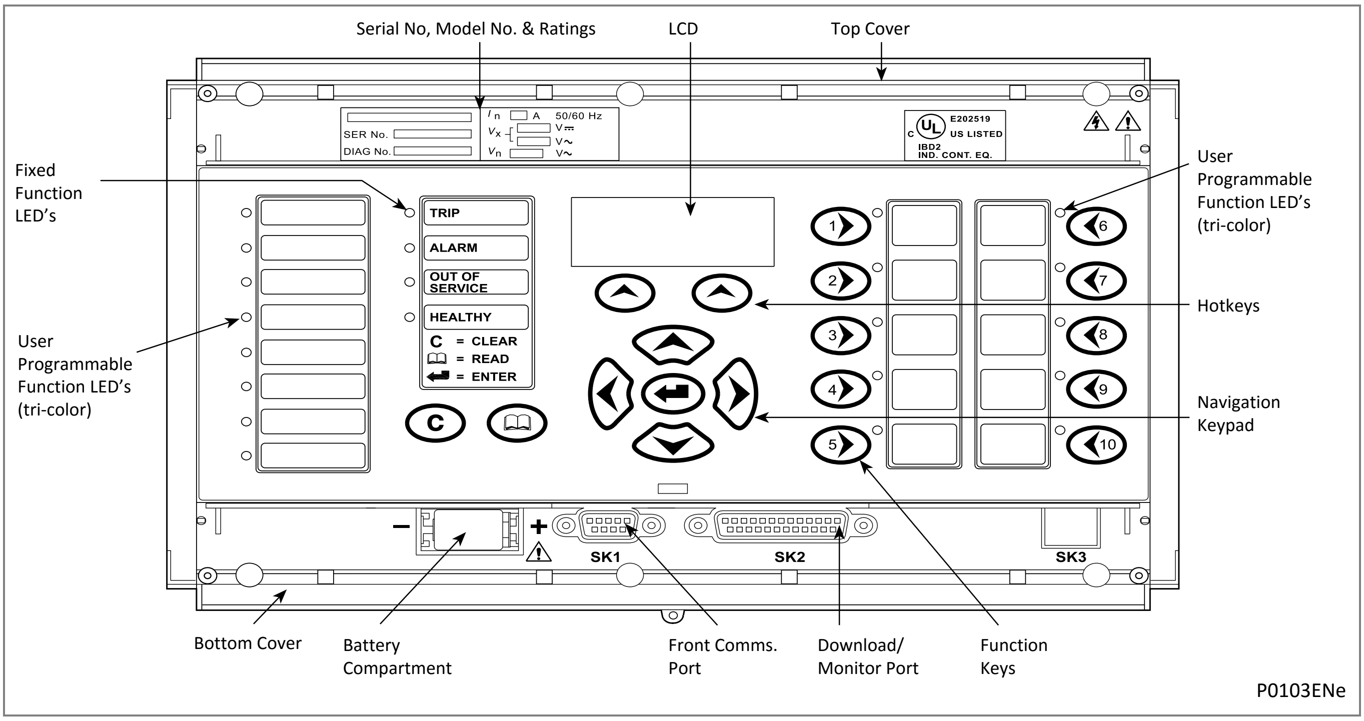

Figure 2 - Relay front view (P343/P344/P345) (60TE case)

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

- A 16-character by 3-line alphanumeric Liquid Crystal Display (LCD).
- A 9-key keypad with 4 arrow keys (, , and), an enter key (), a clear key (), a read key (), 2 hot keys ().
- 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.

Note	The keypad has 19 keys on the P343/P344/P345 and 9 keys on the P342, with the extra 10 keys being the (-) programmable function keys.

Function Key Functionality (for P343/P344/P345):

- 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.

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

1.2.1.1 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 is not fully operational.
- **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 Programmable LEDs

P342: all the programmable LEDs are Red.
P343/P344/P345: all the programmable LEDs are tri-color and can be programmed to indicate Red, Yellow or Green depending on the requirements.

The eight programmable LEDs are suitable for programming alarm indications and the default indications and functions are indicated in the Default LED mappings for P342/P343/P344/P345 table.

P343/P344/P345: the 10 programmable LEDs associated with the function keys, show the status of the associated pushbutton's function. The default indications are shown in the table.

LED No	Default Color	P342	P343/P344/P345
1	Red	Earth Fault Trip -IN>1/2/ISEF>1/IREF>/VN>1/2/3/4/64R R<2 Trip	Earth Fault Trip -IN>1/2/ISEF>1/IREF>/VN>1/2/3/4/5/6/100% ST EF 3H/64S I>1/64S R<2 Trip/64R R<2 Trip
2	Red	Overcurrent Trip - I>1/2/3/4/V Dep OC Trip	Overcurrent Trip - I>1/2/3/4/V Dep OC Trip
3	Red	Field Failure Trip - Field Fail 1/2 Trip	Field Failure Trip - Field Fail 1/2 Trip
4	Red	I2> Trip - I2>1/2/3/4/NPS Thermal Trip	I2> Trip - I2>1/2/3/4/NPS Thermal Trip
5	Red	Voltage Trip - V>2/V<2/V2>1 Trip	Voltage Trip - V>2/V<2/V2>1 Trip
6	Red	Frequency Trip - F>2/F<4/Freq Band 1/2/3/4/5/6 Trip	Frequency Trip - F>2/F<4/Freq Band 1/2/3/4/5/6 Trip
7	Red	Power Trip - Power 1/SPower 1 Trip	Power Trip - Power 1/SPower 1 Trip
8	Red	Any Start	Any Start
F1			Not used
F2			Not used
F3			Not used
F4	Red		Not used
F5	Red		Not used
F6			Not used
F7	Yellow		Reset NPS Thermal State to 0
F8	Yellow		Reset Thermal Overload State to 0
F9	Yellow		Not used
F10	Yellow		Manual Trigger Disturbance Recorder

Table 1 - Default LED mappings for P342/P343/P344/P345

1.3 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.

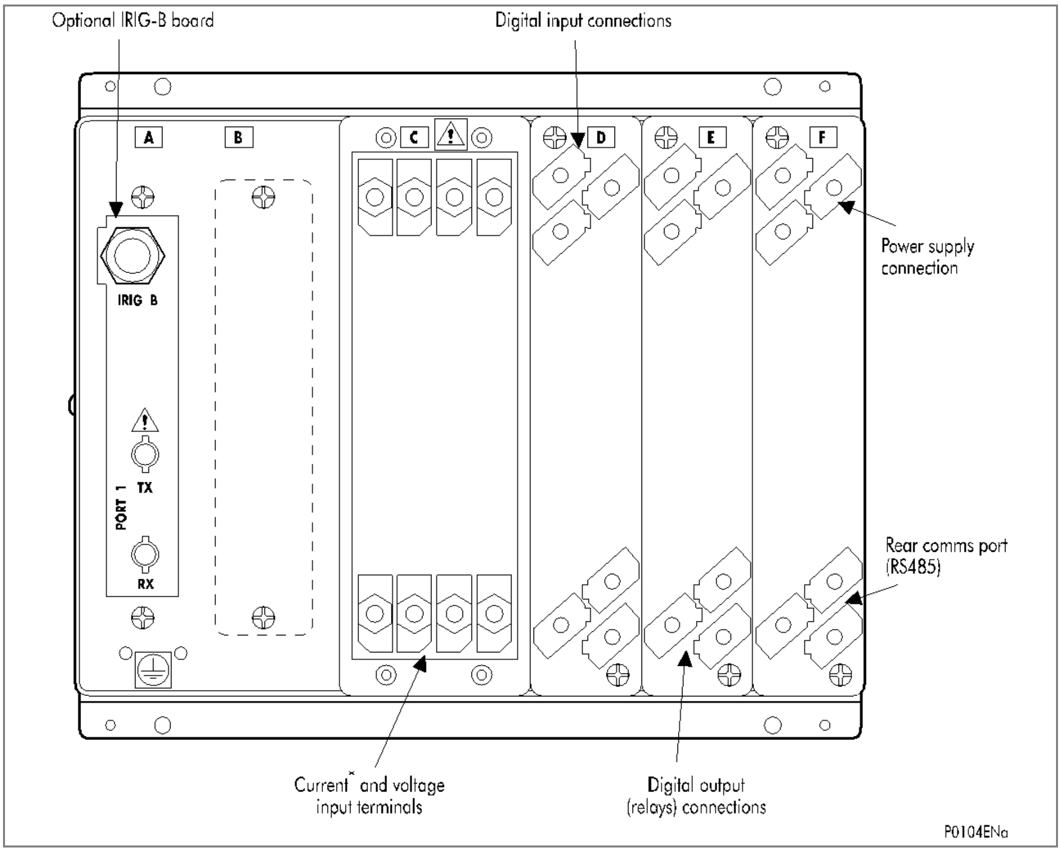

Figure 3 - Relay rear view (40TE case)

1.4 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 Ranges	
dc	**ac**	**dc**	**ac**
24 – 32 V dc	-	19 - 38 V dc	-
48 – 110 V dc	-	37 - 150 V dc	-
110 – 250 V dc **	100 – 240 V ac rms **	87 - 300 V dc	80 - 265 V ac
** rated for ac or dc operation			

Table 2 - Nominal and Operative ranges for dc and ac

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 ***Connection Diagrams*** chapters for all the details, ensuring that the correct polarities are observed in the case of dc supply.

2 USER INTERFACES AND SETTINGS OPTIONS

The relay has these user interfaces:

- front panel user interface via the LCD and keypad
- front port which supports Courier communication
- rear port which supports one protocol of either:
  - Courier
  - Modbus
  - IEC 60870-5-103
  - DNP3.0
- optional Ethernet, dual Ethernet or 9-2 Ethernet port(s)
- optional second rear port which supports Courier protocol

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

The measurement information and relay settings which can be accessed from the different interfaces are summarised in Table 3:

	Keypad or LCD	Courier	MODBUS	IEC870-5-103	DNP3.0	IEC61850
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	
Time synchronisation		Yes	Yes	Yes	Yes	Yes
Control commands	Yes	Yes	Yes	Yes	Yes	

Table 3 - Measurement information and relay settings

3 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.

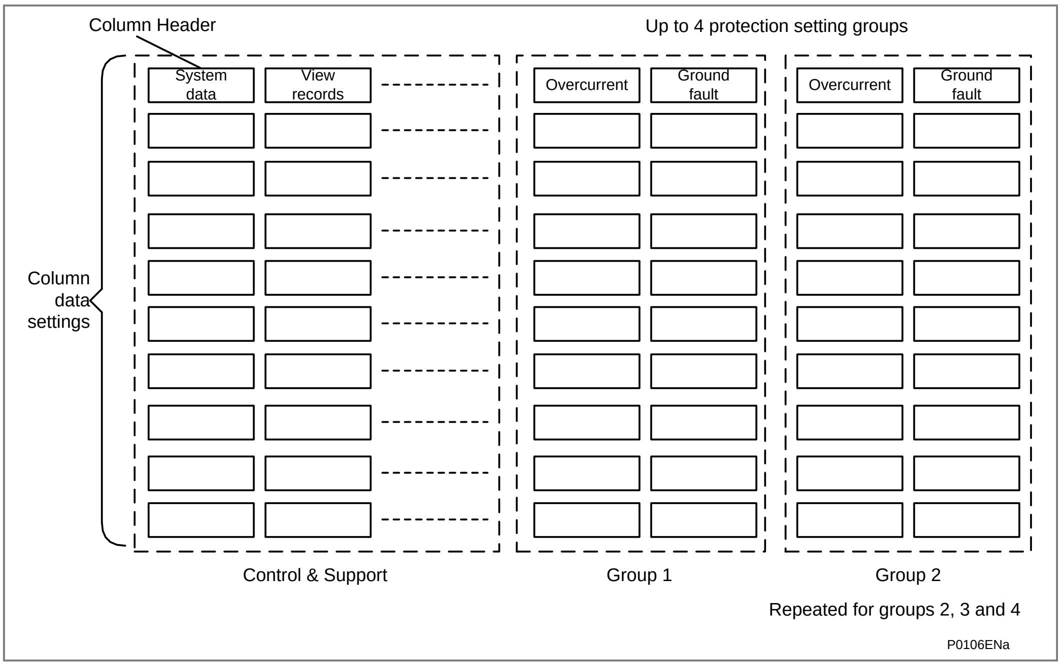

Figure 4 - Menu structure

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.

3.1 Protection Settings

The protection settings include the following items:

- Protection element settings
- Scheme logic settings

There are four groups of protection settings (only two groups for the P24x), 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.

3.2 Disturbance Recorder Settings

The Disturbance Recorder (DR) settings include the record duration and trigger position, selection of analogue and digital signals to record, and the signal sources that trigger the recording.

3.3 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 (may vary according to relay type or model)

4 CYBER SECURITY

4.1 Cyber Security Settings

A detailed description of Schneider Electric Cyber Security features is provided in the *Cyber Security* chapter.

Important	**We would strongly recommend that you understand the contents of the Cyber Security chapter before you use any cyber security features or make any changes to the settings.**

Each MiCOM P40 IED includes a large number of possible settings. These settings are very important in determining how the device works.

A detailed description of the settings is given in the *Cyber Security* chapter.

4.2 Role Based Access Control (RBAC)

The Role Based Access Control (RBAC) is a method to restrict resource access to authorized users. RBAC is an alternative to traditional Mandatory Access Control (MAC) and Discretionary Access Control (DAC).

A key feature of RBAC model is that all access is through roles. A role is essentially a collection of permissions, and all users receive permissions only through the roles to which they are assigned, or through roles they inherit through the role hierarchy.

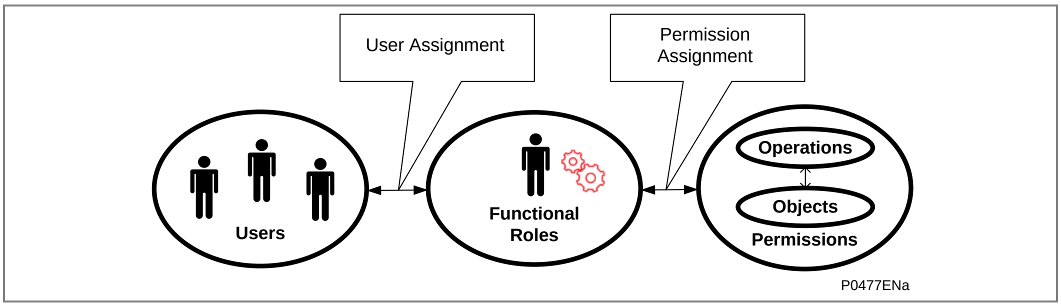

Figure 5 - RBAC Role structure

Roles are created for various job activities. The ***Permissions***, to perform certain operations, are assigned to specific roles. ***Users*** are assigned particular roles, and through those role assignments acquire the computer permissions to perform particular computer-system functions. Since ***users*** are not assigned permissions directly, but only acquire them through their role (or roles), management of individual user rights becomes a matter of simply assigning appropriate roles to the user's account; this simplifies common operations, such as adding a user, or changing user's account.

4.3 User Roles and Rights

Different named roles are associated with different access rights. Roles and Rights are setup in a pre-defined arrangement, according to the IEC62351 standard, but customized to the MiCOM Px4x equipment.

When the user tries to access an IED, they need to login using their own username and their own password. The username/password combination is then checked against the records stored on the IED. If they are allowed to login, a message appears which shows them what Role they have been assigned to. It is the role that defines their access to the relevant parts of the system.

In a similar way in which a set of pre-defined Roles have been created, a pre-defined set of Rights have been created.

These Rights give different permissions to look at what devices may be present, what those devices may contain, manage data within those devices (directly or by using files) and configure rights for other people.

5 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.

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

To do this firstly set the 'Copy from' cell to the protection setting group to be copied, then set the 'Copy to' cell to the protection 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 relay following confirmation.

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 relay's settings, not just the protection groups' settings. The default settings will initially be placed in the scratchpad and will only be used by the relay after they have been confirmed. Note that 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.

6 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 ◁, ▷, △ and ▽ 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.

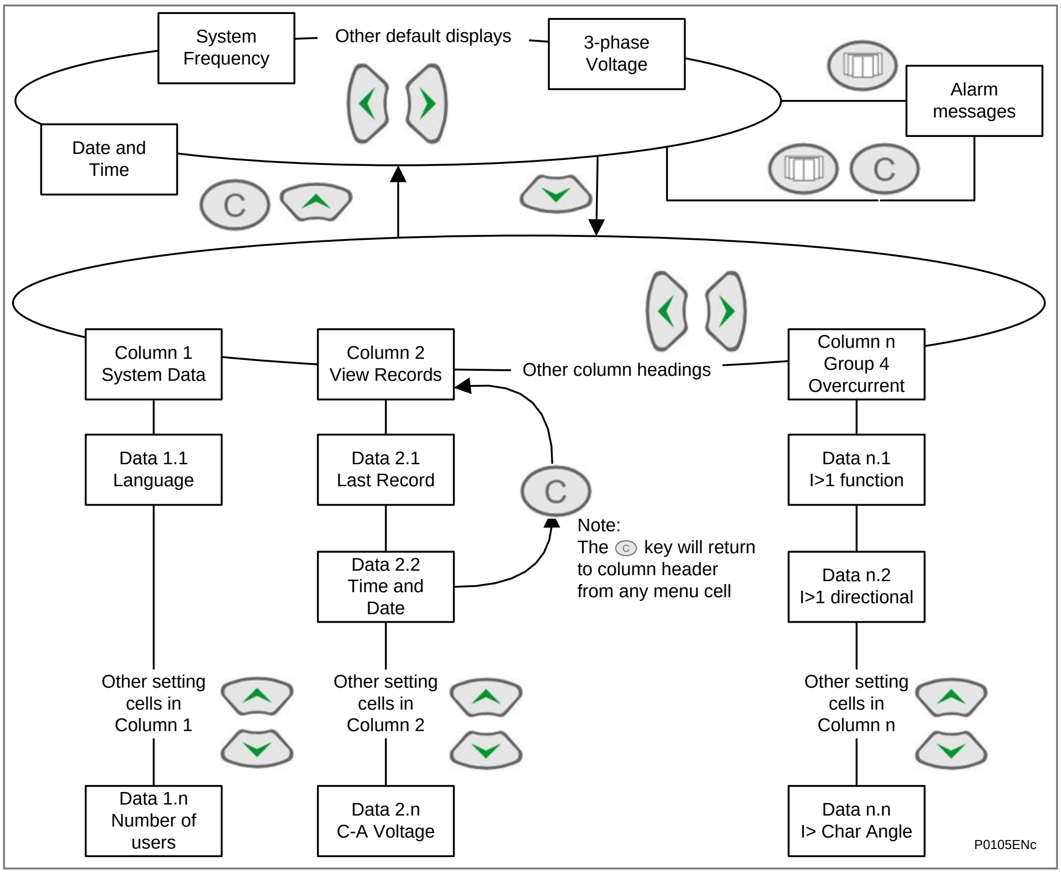

Figure 6 - Front panel user interface

6.1 Default Display and Menu Time-Out

The front panel menu has a default display. To change the default display selection requires password level 3 and the following items can be selected by using the ← and → keys:

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

If the user has got level 3 (or enters a level 3 password when prompted as above), then the IED will then inform the user that to move to another default display will make the IED non-NERC compliant, as follows:

```
DISPLAY NOT-NERC
COMPLIANT. OK?
```

'Enter' will move the default display to the next one, 'Cancel' will leave the display at the user banner display. The confirmation for non-NERC compliance will only be asked when moving off the user banner display. The request for level 3 password will always be asked for any change to the default display selection if the current level is not already 3.

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.

6.2 Navigating Menus and Browsing Settings

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.

6.3 Navigating the Hotkey Menu

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.

6.3.1 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.

6.3.2 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.

6.3.3 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 Setting chapter.

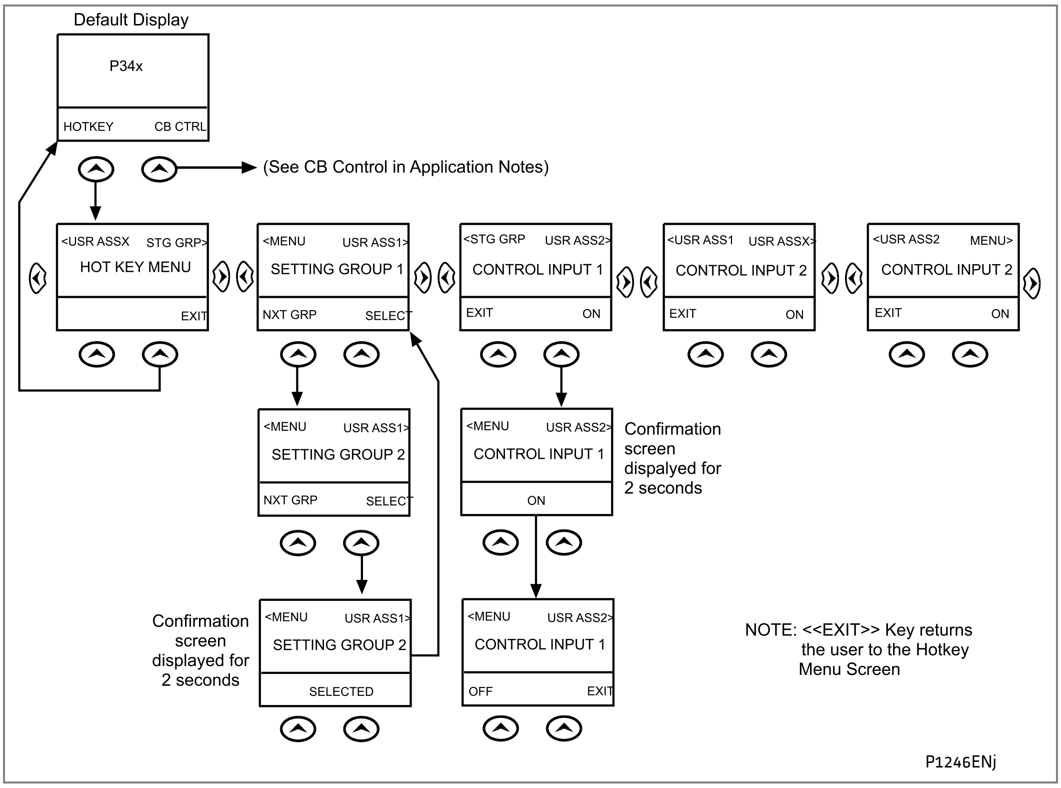

Figure 7 - Hotkey menu navigation

6.4 How to Login

The password entry method varies slightly between CSL0 and CSL1 Versions.

6.4.1 Local Default Access

In CSL0 models the user can access the relay menu without the need to login.
In CSL1 models this can be enabled/disabled using SAT.
If the Local Default Access is enabled, the user may login to the front panel with associated roles.

See Table 4 for the applied cases.

6.4.2 Auto Login

Auto login means the user will login the IED automatically and no need to select the user name and enter the password. In this case, the user will be authorized with relevant rights. The auto login will be applied in these cases:

CS Version	Interface	RBAC/PW Cases	Login Process
CSL1	Front panel	Factory RBAC	Auto login with **EngineerLevel**
		Customized RBAC	Local Default Access Enabled: Login with **Local Default Access** Local Default Access Disabled: Login with **Prompt User List**
	Courier Interface	All cases	Login with **Prompt User List**
CSL0	Front panel	Factory RBAC	Auto login with **EngineerLevel**
		Password changed	**EngineerLevel** password is “AAAA” or is disabled/blank: Auto login with **EngineerLevel** **OperatorLevel** password is “AAAA” or is disabled/blank: Auto login with **OperatorLevel** **EngineerLevel** and **OperatorLevel** password changed: Auto login with **ViewerLevel Access**
	Courier Interface	Factory RBAC	Auto login with **EngineerLevel**
		Password changed	**EngineerLevel** password is “AAAA” or is disabled/blank: Auto login with **EngineerLevel** **OperatorLevel** password is “AAAA” or is disabled/blank: Auto login with **OperatorLevel** **EngineerLevel** and **OperatorLevel** password changed: Login with **Prompt User List**

Table 4 - Auto Login process

For more details about the Factory RBAC, please refer to the Cyber Security chapter.

6.4.3 Login with Prompt User List

This login process will happen if:

- The Auto login process is not applied.
- Or high authorization is required for the current operation.

In this case, the IED will prompt the user list, and the user needs to select proper user name and enter the password to login.

6.5 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.

6.6 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 minutes.
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.

6.7 How to Logout (at the Front Panel)

If you have been configuring the IED, you should 'log out'. You do this by going up to the top of the menu tree. When you are at the Column Heading level and you press the Up button, you may be prompted to log out with the following display:

```
ENTER TO LOG OUT
CLEAR TO CANCEL
```

You will only be asked this question if your password level is higher than the fallback level.

If you confirm, the following message is displayed for 2 seconds:

```
LOGGED OUT
Access Level <x>
```

Where x is the current fallback level.

If you decide not to log out (i.e. you cancel), the following message is displayed for 2 seconds.

```
LOGOUT CANCELLED
Access Level <x>
```

Where x is the current access level.

7 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 Easergy Studio (MiCOM S1 Studio).

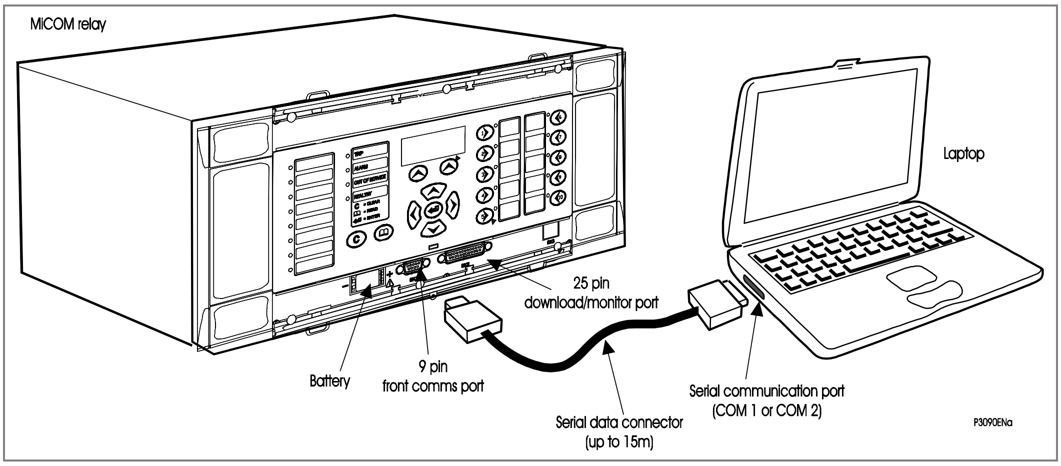

Figure 8 - Front port connection

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 – IED serial 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 – IED serial port 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.*

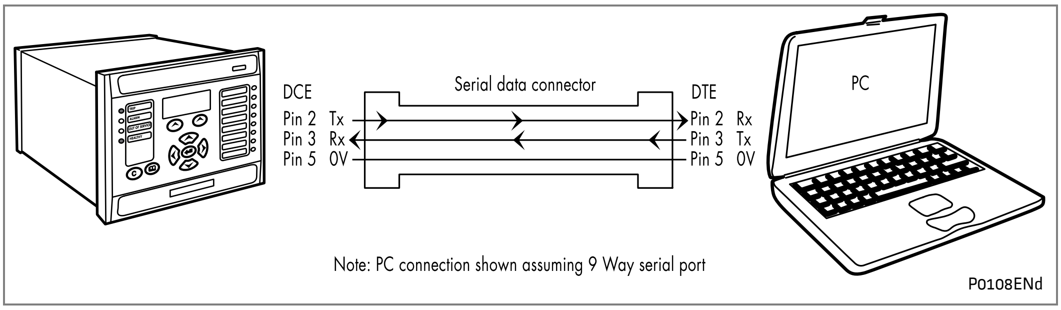

Figure 9 - PC relay signal connection

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.

7.1 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.*

8 EASERGY STUDIO (MICOM S1 STUDIO) COMMUNICATIONS BASICS

The EIA(RS)232 front communication port is particularly designed for use with the relay settings program Easergy Studio (MiCOM S1 Studio). Easergy 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.

Easergy Studio (MiCOM S1 Studio) provides full access to MiCOM Px10, Px20, Px30, Px40 and Mx20 measurements units.

The Easergy Studio (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 Easergy Studio (MiCOM S1 Studio).**

8.1 PC Requirements

The minimum and recommended hardware requirements for Easergy Studio (MiCOM S1 Studio) (v7.0.0) are shown below. These include the Studio application and other tools which are included: UPCT, P746 RHMI, P74x Topology Tool:

Minimum requirements:				
Platform	**Processor**	**RAM**	**HDD (Note 1 & 3)**	**HDD (Note 2 & 3)**
Windows XP x86	1 GHz	512 MB	900 MB	1.5 GB
Windows 7 x86	1 GHz	1 GB	900 MB	1.9 GB
Windows 7 x64	1 GHz	2 GB	900 MB	2.1 GB
Windows Server 2008 x86 Sp1	1 GHz	512 MB	900 MB	1.7 GB

Recommended requirements:				
Platform	**Processor**	**RAM**	**HDD (Note 1 & 3)**	**HDD (Note 2 & 3)**
Windows XP x86	1 GHz	1 GB	900 MB	1.5 GB
Windows 7 x86	1 GHz	2 GB	900 MB	1.9 GB
Windows 7 x64	1 GHz	4 GB	900 MB	2.1 GB
Windows Server 2008 x86 Sp1	1 GHz	4 GB	900 MB	1.7 GB

Note 1	*Operating system with Windows Updates updated on 2015/05.*
Note 2	*Operating system without Windows Updates installed.*
Note 3	*Both configurations do not include Data Models HDD requirements. Data Models typically need from 1 GB to 15 GB of hard disk space.*

Screen resolution for minimum requirements: Super VGA (800 x 600).
Screen resolution for recommended requirements: XGA (1024x768) and higher.
Easergy Studio (MiCOM S1 Studio) must be started with Administrator privileges.

Easergy Studio (MiCOM S1 Studio) Additional components

The following components are required to run Easergy Studio (MiCOM S1 Studio) and are installed by its installation package.

Component Type	Component
Package	.NET Framework 2.0 SP 1 (x64)
Package	.NET Framework 2.0 SP 1 (x86)
Package	.NET Framework 4.0 Client (x64)
Package	.NET Framework 4.0 Client (x86)
Package	Visual C++ 2005 SP1 Redistributable Package (x86)
Package	Visual C++ 2008 SP1 Redistributable Package (x86)
Merge modules	DAO 3.50
Merge modules	MFC 6.0
Merge modules	MFC Unicode 6.0
Merge modules	Microsoft C Runtime Library 6.0
Merge modules	Microsoft C++ Runtime Library 6.0
Merge modules	Microsoft Component Category Manager Library
Merge modules	Microsoft Data Access Components 2.8 (English)
Merge modules	Microsoft Jet Database Engine 3.51 (English)
Merge modules	Microsoft OLE 2.40 for Windows NT and Windows 95
Merge modules	Microsoft Visual Basic Virtual Machine 6.0
Merge modules	MSXML 4.0 - Windows 9x and later
Merge modules	MSXML 4.0 - Windows XP and later
Merge modules	Visual C++ 8.0 MFC (x86) WinSXS MSM
Merge modules	Visual C++ 8.0 MFC.Policy (x86) WinSXS MSM

8.2 Connecting to the Relay using Easergy Studio (MiCOM S1 Studio)

This section is a quick start guide to using Easergy Studio (MiCOM S1 Studio) and assumes this is installed on your PC. See the Easergy Studio (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. (User Login necessary)

8.3 Off-Line Use of Easergy Studio (MiCOM S1 Studio)

Easergy 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. If the IEC61850 protocol is selected, and an Ethernet board with hardware option Q, R or S is selected, select IEC 61850 Edition:
   IEC 61850 Edition 2 Mode or
   IEC 61850 Edition 1 Compatible Mode.
9. Enter a unique device name, then click **Finish**.
10. Right-click the **Settings** folder and select **New File**. A default file **000** is added.
11. Right-click file **000** and select click **Open**. You can then edit the settings. See the Easergy Studio (MiCOM S1 Studio) program online help for more information.

Notes:

SETTINGS

CHAPTER 4

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

CONTENTS

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TABLES

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.

Important	***The following tables provide information about the different settings for this range of MiCOM products. Unless otherwise stated in these tables, the settings apply to the whole range of products covered by this manual. Where a setting applies to anything other than the whole range, the individual products to which it applies are listed accordingly.***

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 Default Settings Restore

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.

Important	***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.***

Important	***If you restore settings, the settings for the IEC 61850 Edition and the Communications Mode will not be restored, even if "Restore All Settings" is set.***

3 CONFIGURATION MENU

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CONFIGURATION	09	00		
This column contains all the general configuration options				
Restore Defaults	09	01	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	09	02	Select via Menu	Select from Menu, Select from PSL
Allows setting group changes to be initiated using 2 DDB signals in the programmable scheme logic or from the Menu settings.				
Active Settings	09	03	Group 1	Group 1, Group 2, Group 3, Group 4
Selects the active setting group.				
Save Changes	09	04	No Operation	No Operation, Save, Abort
Saves all relay settings.				
Copy From	09	05	Group 1	Group 1, Group 2, Group 3, Group 4
Allows displayed settings to be copied from a selected setting group.				
Copy To	09	06	No Operation	No Operation, Group 1, Group 2, Group 3, Group 4
Allows displayed settings to be copied to a selected setting group.				
Setting Group 1	09	07	Enabled	Enabled, Disabled
Enables or disables Group 1 settings. If the setting group is disabled from the configuration, all associated settings and signals are hidden, with the exception of this setting.				
Setting Group 2	09	08	Disabled	Enabled, Disabled
Setting Group 2 works in the same way as Setting Group 1.				
Setting Group 3	09	09	Disabled	Enabled, Disabled
Setting Group 3 works in the same way as Setting Group 1.				
Setting Group 4	09	0A	Disabled	Enabled, Disabled
Setting Group 4 works in the same way as Setting Group 1.				
System Config	09	0B	Visible	Invisible, Visible
Sets the System Config menu visible further on in the IED setting menu.				
Power	09	0C	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Power protection function.				
Field Failure	09	0D	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Field Failure protection function.				
NPS Thermal	09	0E	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the NPS Thermal protection function.				
System Backup	09	0F	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the System Backup protection function.				
Overcurrent	09	10	Enabled	Enabled, Disabled
Enables (activates) or disables (turns off) the overcurrent protection: ANSI 50/51/67P, 46OC.				
Thermal Overload	09	11	Disabled	Enabled, Disabled
Enables (activates) or disables (turns off) the Thermal Overload Protection: ANSI 49.				
Differential	09	12	Enabled	Enabled, Disabled
Enables (activates) or disables (turns off) the differential protection. The unit provides bias differential protection with multiple CT inputs. (P343/P344/P345)				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Earth Fault	09	13	Enabled	Enabled, Disabled
Enables (activates) or disables (turns off) the Earth Fault Protection: ANSI 50N/51N.				
Rotor EF	09	14	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Rotor EF protection function.				
SEF/REF/SPower	09	15	SEF/REF	0 = Disabled, 1 = SEF/REF, 2 = Sensitive Power
To enable (activate) or disable (turn off) the Sensitive Earth Fault/Restricted Earth fault/ Sensitive Power Protection function. ISEF >stages: ANSI 50/51/67N. IREF>stage: ANSI 64.				
Residual O/V NVD	09	16	Enabled	Enabled, Disabled
Enables (activates) or disables (turns off) the Residual Overvoltage (Neutral Voltage Displacement) Protection function: ANSI 59N.				
100% Stator EF	09	17	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the 100% Stator EF protection function. (P343/P344/P345)				
V/Hz	09	18	Disabled	Enabled, Disabled
To enable (activate) or disable (turn off) the V/Hz protection function.				
df/dt	09	19	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Rate of change of Frequency Protection function. df/dt> stages: ANSI 81R.				
V Vector Shift	09	1A	Disabled	Enabled, Disabled
To enable (activate) or disable (turn off) the V Vector Shift protection function.				
Dead Machine	09	1B	Disabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Dead Machine protection function. (P343/P344/P345)				
Reconnect Delay	09	1C	Disabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Reconnect Delay protection function.				
Volt Protection	09	1D	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Voltage Protection (under/overvoltage) function. V<, V> stages: ANSI 27/59.				
Freq Protection	09	1E	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Frequency Protection (under/over frequency) function. F<, F> stages: ANSI 81O/U.				
RTD Inputs	09	1F	Enabled	Enabled, Disabled
Sets the RTD Labels menu visible in the relay settings menu.				
CB Fail	09	20	Disabled	Enabled, Disabled
Enables (activates) or disables (turns off) the Circuit Breaker Fail Protection function: ANSI 50BF.				
Supervision	09	21	Disabled	Enabled, Disabled
Enables (activates) or disables (turns off) the Supervision (VTS, CTS & Through Fault) functions				
Dynamic Rating	09	23	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Dynamic Rating protection function.				
Pole Slipping	09	24	Enabled	Enabled, Disabled
To enable (activate) or disable (turn off) the Pole Slipping protection function. (P343/P344/P345)				
Input Labels	09	25	Visible	Invisible, Visible
Sets the Input Labels menu visible in the relay settings menu.				
Output Labels	09	26	Visible	Invisible, Visible
Sets the Output Labels menu to visible in the relay settings menu.				
RTD Labels	09	27	Visible	Invisible, Visible
Sets the RTD Labels menu visible in the relay settings menu.				
CT & VT Ratios	09	28	Visible	Invisible, Visible

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Sets the Current & Voltage Transformer Ratios menu visible in the relay settings menu.				
Record Control	09	29	Visible	Invisible, Visible
Sets the Record Control menu visible in the relay settings menu.				
Disturb Recorder	09	2A	Visible	Invisible, Visible
Sets the Disturbance Recorder menu visible in the relay settings menu.				
Measure't Setup	09	2B	Visible	Invisible, Visible
Sets the Measurement Setup menu visible in the relay settings menu.				
Comms Settings	09	2C	Visible	Invisible, Visible
Sets the Communications Settings menu visible in the relay settings menu. These are the settings associated with the 1st and 2nd rear communications ports.				
Commission Tests	09	2D	Visible	Invisible, Visible
Sets the Commissioning Tests menu visible in the relay settings menu.				
Setting Values	09	2E	Primary	0 = Primary, 1 = Secondary
This affects all protection settings that are dependent on CT and VT ratios.				
Control Inputs	09	2F	Visible	Invisible, Visible
Sets the Control Inputs menu visible in the relay setting menu.				
CLIO Inputs	09	30	Enabled	Enabled, Disabled
Enables (activates) or disables (turns off) the CLIO (Current Loop Input Output) Input function.				
CLIO Outputs	09	31	Enabled	Enabled, Disabled
Enables (activates) or disables (turns off) the CLIO (Current Loop Input Output) Outputs function.				
System Checks	09	33	Disabled	Disabled, Enabled
To enable (activate) or disable (turn off) the System Checks (Check Sync. and Voltage Monitor) function: ANSI 25.				
Ctrl I/P Config	09	35	Visible	Invisible, Visible
Sets the Control Input Configuration menu visible in the relay setting menu.				
Ctrl I/P Labels	09	36	Visible	Invisible, Visible
Sets the Control Input Labels menu visible in the relay setting menu.				
Direct Access	09	39	Enabled	Disabled, Enabled
Defines what controls are available using the direct access keys - Enabled (Hotkey). Not available on Chinese version relays (P34???????C????)				
Function Key	09	50	Visible	Invisible, Visible
Sets the Function Key menu visible in the relay setting menu. (P343/P344/P345)				
VIR I/P Labels	09	70	Invisible	0 = Invisible, 1 = Visible
This makes the virtual inputs label settings visible or invisible.				
VIR O/P Labels	09	80	Invisible	0 = Invisible, 1 = Visible
This makes the virtual outputs label settings visible or invisible.				
Usr Alarm Labels	09	90	Invisible	0 = Invisible, 1 = Visible
This makes the user alarm labels settings visible or invisible.				
RP1 Read Only	09	FB	Disabled	Enabled, Disabled
Enable Remote Read Only Mode on RP1 courier				
RP2 Read Only	09	FC	Disabled	Enabled, Disabled
Enable Remote Read Only Mode on RP2 courier communication protocol. Visible when hardware options are: 7 or 8				
NIC Read Only	09	FD	Disabled	Enabled, Disabled
Ethernet versions only. To enable (activate) or disable (turn off) Read Only Mode of Network Interface Card.				
LCD Contrast	09	FF	11	0 to 31 step 1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Sets the LCD contrast.				

Table 1 - General configuration settings

4 GROUPED 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).

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. The settings for group 1 are shown. The settings are discussed in the same order in which they are displayed in the menu.

4.1 System Config

The relay maintains correct operation of all the protection functions even when the generator is running in a reverse phase sequence and for generator-transformer applications. This is achieved through user configurable settings available for the four setting groups.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 SYSTEM CONFIG	30	00		
GROUP 1 SYSTEM CONFIG				
Winding Config	30	01	Generator	Generator, Xformer
The winding type may be configured as Generator or Xformer (Generator-transformer). This setting makes the Generator Diff or Xformer Diff settings visible in the DIFFERENTIAL menu.				
Ref Power S	30	02	100 VA	0.1 VA to 5000 VA step 0.1 VA
Reference power. Used by the differential function to calculate the ratio correction factors. Used by the transformer thermal function to calculate the rated load current.				
HV Connection	30	11	Y-Wye	Y-Wye, D-Delta, Z-Zigzag
The HV winding connections can be configured as Wye, Delta, or Zigzag. (P343/P344/P345)				
HV Grounding	30	12	Grounded	Grounded, Ungrounded
In DIFFERENTIAL menu, the Set Mode setting can be set as Simple or Advanced. In simple mode when set as grounded, the P34x applies zero sequence filtering to the HV side current. When set as ungrounded, no zero sequence filtering is applied to the HV side current. In advanced mode, the HV Grounding setting is only for information and the zero sequence filtering depends on the Zero seq filt HV setting. While Zero seq filt HV is set as Enabled, the HV Grounding setting will be set as Grounded automatically. (P343/P344/P345)				
HV Nominal	30	13	220 kV	From 100 V to 1 MV step 1 V
Nominal voltage of the HV winding. Typically set to the mid-tap voltage of the on-load tap changer, or no-load tap changer tap voltage. (P343/P344/P345)				
% Reactance	30	20	0.1	1% to 100% step 0.01%
Transformer leakage reactance. (P343/P344/P345)				
LV Vector Group	30	31	0	0 to 11 step 1
This is used to provide vector correction for the phase shift between HV and LV windings. (P343/P344/P345)				
LV Connection	30	32	Y-Wye	Y-Wye, D-Delta, Z-Zigzag
The LV winding connections can be configured as Wye, Delta, or Zigzag. (P343/P344/P345)				
LV Grounding	30	33	Grounded	Grounded, Ungrounded
In DIFFERENTIAL menu, the Set Mode setting can be set as Simple or Advanced. In simple mode when set as grounded, the P34x applies zero sequence filtering to the LV side current. When set as ungrounded, no zero sequence filtering is applied to the LV side current. In advanced mode, the LV Grounding setting is only for information, and the zero sequence filtering depends on the Zero seq filt LV setting. While Zero seq filt LV is set as Enabled, the LV Grounding setting will be set as Grounded automatically. (P343/P344/P345)				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
LV Nominal	30	34	11kV	From 100 V to 1 MV step 1 V
Nominal voltage of the LV winding. Typically set to the mid-tap voltage of the on-load tap changer, or no-load tap changer tap voltage.				
Match Factor HV	30	40		Not Settable
HV ratio correction factor used by the differential function. (P343/P344/P345)				
Match Factor LV	30	41		Not Settable
LV ratio correction factor used by the differential function. (P343/P344/P345)				
Phase Sequence	30	42	Standard ABC	0 = Standard ABC, 1 = Reverse ACB
The Phase Sequence setting applies to a power system that has a permanent phase sequence of either ABC or ACB. It is also applicable for temporary phase reversal which affects all the 3-phase VTs and CTs.				
VT Reversal	30	43	No Swap	0 = No Swap, 1 = A-B Swapped, 2 = B-C Swapped, 3 = C-A Swapped
The VT Reversal settings apply to applications where some or all of the 3-phase voltage or current inputs are temporarily reversed, as in pump storage applications. The settings affect the order of the analogue channels in the relay and are set to emulate the order of the channels on the power system.				
CT Reversal CT1 Reversal	30	44	No Swap	0 = No Swap, 1 = A-B Swapped, 2 = B-C Swapped, 3 = C-A Swapped
The CT Reversal/CT1 Reversal settings apply to applications where some or all of the 3-phase voltage or current inputs are temporarily reversed, as in pump storage applications. The settings affect the order of the analogue channels in the relay and are set to emulate the order of the channels on the power system. CT Reversal is for P342, otherwise CT1 Reversal is for P343/P344/P345.				
CT2 Reversal	30	45	No Swap	0 = No Swap, 1 = A-B Swapped, 2 = B-C Swapped, 3 = C-A Swapped
The CT2 Reversal settings apply to applications where some or all of the 3-phase voltage or current inputs are temporarily reversed, as in pump storage applications. The settings affect the order of the analogue channels in the relay and are set to emulate the order of the channels on the power system. P343/P344/P345 only.				
C/S Input	30	50	A-N	A-N, B-N, C-N, A-B, B-C, C-A
Selects the check synchronizing input voltage measurement.				
C/S V Ratio Corr	30	51	1	0.1 to 2 step 0.001
Check synchronizing voltage ratio correction. This is used by the System Check function to provide the magnitude correction for the difference between main VT and C/S VT. The Main VT is the reference, and the C/S VT is corrected to Main VT. The formula is: VC/S VT Corrected = VC/S VT * C/S Ratio Corr.				
C/S VT Vect Grp	30	52	0	0 to 11 step 1
This is used to provide vector correction for the phase shift between main VT and C/S VT. The Main VT is the reference, and the C/S VT is corrected to Main VT. Two examples are shown below: Case1 (Main VT Location = Gen): For C/S VT Vect Grp = 0~5 The formula is: Θc/s VT Corrected = θC/S VT - (C/S VT Vect Grp)*30°; And for C/S VT Vect Grp = 6~11 θc/s VT Corrected = θC/S VT + (12-C/S VT Vect Grp)*30°. Case 2 (Main VT Location = Bus): For C/S VT Vect Grp = 0~5 The formula is: Θc/s VT Corrected = θC/S VT + (C/S VT Vect Grp)*30°; And for C/S VT Vect Grp = 6~11 θc/s VT Corrected=θC/S VT - (12-C/S VT Vect Grp)*30°.				
C/S VT Location	30	53	Gen	Gen or Bus
Neutral Displacement VT Primary Selects the main voltage transformer location, Generator or Busbar.				

Table 2 - System configuration settings

4.2 Power Protection (32R/32L/32O)

The 3-phase power protection included in the relay provides two stages of power protection. Each stage can be independently selected as either reverse power, overpower, low forward power or disabled. The direction of operation of the power protection, forward or reverse, can also be defined with the operating mode setting. There is also a single stage NPS overpower protection function.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 POWER	31	00		
GROUP 1 POWER				
Operating Mode	31	20	Generating	0 = Generating, 1 = Motoring
Operating mode of the power protection defining forward/reverse direction – Generating = forward power towards the busbar, Motoring = forward power towards the machine. Assumes CT connections as per standard connection diagrams.				
Power1 Function	31	24	Over	0 = Disabled, 1 = Reverse, 2 = Low Forward, 3 = Over
First stage power function operating mode.				
-P>1 Setting	31	28	5*V1*In	1*V1*In to 300*V1*In step 0.2*V1*In
Pick-up setting for the first stage reverse power protection element.				
P<1 Setting	31	2C	10*V1*In	1*V1*In to 300*V1*In step 0.2*V1*In
Pick-up setting for the first stage low forward power protection element.				
P>1 Setting	31	30	120*V1*In	1*V1*In to 300*V1*In step 0.2*V1*In
Pick-up setting for the first stage overpower protection element.				
Power1 TimeDelay	31	34	5 s	0 s to 100 s step 1 s
Operating time-delay setting of the first stage power protection.				
Power1 DO Timer	31	38	0 s	0 s to 100 s step 1 s
Drop-off time delay setting of the first stage power protection function. Setting of the drop-off timer to a value other than zero, delays the resetting of the protection element timers for this period. By using the drop-off timer the relay will integrate the fault power pulses, thereby reducing fault clearance times.				
P1 Poledead Inh	31	3C	Enabled	Disabled, Enabled
If the setting 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 power protection to reset when the circuit breaker opens to cater for line or bus side VT applications.				
Power2 Function	31	40	Low Forward	0 = Disabled, 1 = Reverse, 2 = Low Forward, 3 = Over
Second stage power function operating mode.				
-P>2 Setting	31	44	5*V1*In	1*V1*In to 300*V1*In step 0.2*V1*In
Pick-up setting for the second stage reverse power protection element.				
P<2 Setting	31	48	10*V1*In	1*V1*In to 300*V1*In step 0.2*V1*In
Pick-up setting for the second stage low forward power protection element.				
P>2 Setting	31	4C	120*V1*In	1*V1*In to 300*V1*In step 0.2*V1*In
Pick-up setting for the second stage overpower protection element.				
Power2 TimeDelay	31	50	2 s	0 s to 100 s step 1 s
Operating time-delay setting of the second stage power protection.				
Power2 DO Timer	31	54	0 s	0 s to 100 s step 1 s
Drop-off time delay setting of the second stage power protection function. Setting of the drop-off timer to a value other than zero, delays the resetting of the protection element timers for this period. By using the drop-off timer the relay will integrate the fault power pulses, thereby reducing fault clearance times.				
P2 Poledead Inh	31	58	Enabled	Disabled, Enabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
If the setting 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 power protection to reset when the circuit breaker opens to cater for line or bus side VT applications.				
NPS OVERPOWER	31	60		
S2> CT Source	31	61	IA-1 IB1-1 IC-1	0 = IA1-1 IB-1 IC-1, 1 =IA1-2 IB-2 IC-2
This setting is used to select the 3-phase current inputs used by the NPS OVERPOWER protection elements in the P343/P344/P345 - IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 CT inputs.				
S2>1 Status	31	62	Disabled	Disabled, Enabled
Enables or disables the Negative Phase Sequence Overpower function.				
S2>1 Setting	31	64	0.5*V1*In	0.1*V1*I4 to 30*V1*I4 step 0.01*V1*I4
Pick-up setting for the NPS overpower protection element				
S2>1 Time Delay	31	68	0.1 s	0 s to 100 s step 10 ms
Operating time-delay setting of the NPS overpower protection.				

Table 3 - Power protection settings

4.3 Field Failure Protection (40)

The field failure protection included in the relay provides two impedance based stages of protection and a leading power factor alarm element.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 FIELD FAILURE	32	00		
GROUP 1 FIELD FAILURE				
FFail Alm Status	32	01	Disabled	Disabled or Enabled
Enables or disables the Field Failure Alarm function.				
FFail Alm Angle	32	02	15 °	15 ° to 75 ° step 1 °
Pick-up setting for field failure alarm angle (leading power factor angle).				
FFail Alm Delay	32	03	5 s	0 s to 100 s step 10 ms
Operating time-delay setting of the field failure alarm.				
FFail1 Status	32	04	Enabled	Disabled or Enabled
Enables or disables the first stage field failure protection function.				
FFail1 -Xa1	32	05	20*V1/In	0 to 40*V1/In step 0.5*V1/In
Negative reactance offset setting of first stage field failure impedance protection.				
FFail1 Xb1	32	06	220*V1/In	25*V1/In to 325*V1/In step 1*V1/In
Diameter setting of circular impedance characteristic of first stage field failure protection.				
FFail1 TimeDelay	32	07	5 s	0 s to 100 s step 10 ms
Operating time-delay setting of the field failure first stage protection.				
FFail1 DO Timer	32	08	0 s	0 s to 100 s step 10 ms
Drop-off time delay setting of the first stage field failure protection function. Setting of the drop-off timer to a value other than zero, delays the resetting of the protection element timers for this period. By using the drop-off timer the relay will integrate the fault impedance pulses, for example during pole slipping, thereby reducing fault clearance times.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
FFail2 Status	32	09	Disabled	Disabled or Enabled
Enables or disables the second stage field failure protection function.				
FFail2 -Xa2	32	0A	20*V1/In	0 to 40*V1/In step 0.5*V1/In
Negative reactance offset setting of second stage field failure impedance protection.				
FFail2 Xb2	32	0B	110*V1/In	25*V1/In to 325*V1/In step 1*V1/In
Diameter setting of circular impedance characteristic of second stage field failure protection.				
FFail2 TimeDelay	32	0C	0 s	0 s to 100 s step 10 ms
Operating time-delay setting of the field failure second stage protection.				
FFail2 DO Timer	32	0D	0 s	0 s to 100 s step 10 ms
Drop-off time delay setting of the second stage field failure protection function. Setting of the drop-off timer to a value other than zero, delays the resetting of the protection element timers for this period. By using the drop-off timer the relay will integrate the fault impedance pulses, for example during pole slipping, thereby reducing fault clearance times.				

Table 4 - Field failure protection settings

4.4 Negative Phase Sequence (NPS) Thermal (46T)

The Negative Phase Sequence (NPS) Thermal Protection included in the relay provides a definite time alarm stage and a thermal trip stage.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 NPS THERMAL	33	00		
GROUP 1 NPS THERMAL				
I2therm>1 Alarm	33	01	Enabled	Disabled, Enabled
Enables or disables the negative phase sequence (NPS) Thermal Alarm function.				
I2therm>1 Set	33	02	0.05*In	From 0.03*In to 0.5*In step 0.01*In
Pick-up setting for NPS thermal alarm.				
I2therm>1 Delay	33	03	20 s	From 0 s to 100 s step 10 ms
Operating time-delay of the NPS thermal alarm.				
I2therm>2 Trip	33	04	Enabled	Disabled, Enabled
Enables or disables the NPS Thermal Trip function.				
I2therm>2 Set	33	05	0.1*In	From 0.05*In to 0.5*In step 0.01*In
Pick-up setting for NPS thermal trip.				
I2therm>2 kSet	33	06	15 s	From 2 s to 40 s step 100 ms
Thermal capacity constant setting of the NPS thermal characteristic.				
I2therm>2 kRESET	33	07	15 s	From 2 s to 40 s step 100 ms
Reset (cooling) thermal capacity constant setting of the NPS thermal characteristic.				
I2therm>2 tMAX	33	08	1000 s	From 500 s to 2000 s step 1 s
Maximum operating time setting of the NPS thermal characteristic.				
I2therm>2 tMIN	33	09	250 ms	From 0 s to 100 s step 10 ms
Minimum operating time setting of the NPS thermal characteristic				

Table 5 - NPS thermal protection settings

4.5 System Backup Protection

The system backup protection included in the relay provides a single stage of voltage restrained or voltage controlled overcurrent protection or a two stage underimpedance protection.

The voltage dependent overcurrent protection has time-delayed characteristics which are selectable between Inverse Definite Minimum Time (IDMT), or Definite Time (DT). The underimpedance protection is definite time only.

The voltage controlled overcurrent pick-up setting (V Dep OC I> Set) is modified by a multiplying factor (V Dep OC k Set) when the voltage is below a specific voltage (V Dep OC V<1Set).

The voltage restrained overcurrent pick-up setting varies on a linear scale between the two voltage thresholds, V Dep OC V<1 Set and V Dep OC V<2 Set. The pick-up setting is V Dep OC I> Set when the voltage is greater than V Dep OC V<1 Set and is V Dep OC I> Set x V Dep OC k Set when the voltage is less than V Dep OC V<2 Set.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 SYSTEM BACKUP	34	00		
GROUP 1 SYSTEM BACKUP				
Backup Function	34	01	Voltage controlled	0 = Disabled, 1 = Underimpedance, 2 = Volt Controlled, 3 = Volt Restrained
System backup protection operating function.				
Vector Rotation	34	02	None	0 = None, 1 = Delta-Star
Selection of Delta-Star voltage vector correction, enabled where there is a delta-star step-up transformer to improve sensitivity for HV phase faults.				
V Dep OC Char	34	20	IEC S Inverse	DT, IEC S Inverse, IEC V Inverse, IEC E Inverse, UK LT Inverse, Rectifier, RI, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse
Selection of the tripping characteristic for the voltage dependent overcurrent protection.				
V Dep OC I> Set	34	23	1*In	0.8*In to 4*In step 0.01*In
Pick-up setting for voltage controlled and restrained overcurrent trip.				
V Dep OC T Dial	34	25	1	0.01 to 100 step 0.01
Time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
V Dep OC Reset	34	26	DT	0 = DT, 1 = Inverse
Type of reset/release characteristic of the IEEE/US curves.				
V Dep OC Delay	34	27	1 s	0 s to 100 s step 10 ms
Operating time-delay setting for the definite time setting if selected for the voltage controlled or restrained overcurrent protection.				
V Dep OC TMS	34	28	1	0.025 to 1.2 step 0.025
Time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
V Dep OC K (RI)	34	29	1	0.1 to 10 step 0.05
Time multiplier setting to adjust the operating time for the RI curve.				
V Dep OC tRESET	34	2A	0 s	0 s to 100 s step 10 ms
Reset/release time setting for definite time reset characteristic.				
V Dep OC V<1 Set	34	2D	80*V1	5*V1 to 120*V1 step 1*V1
Undervoltage setting for voltage controlled and restrained overcurrent characteristic.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
V Dep OC V<2 Set	34	2E	60*V1	5*V1 to 120*V1 step 1*V1
Undervoltage setting for voltage restrained overcurrent characteristic.				
V Dep OC k Set	34	2F	0.25	0.1 to 1 step 0.05
Multiplying factor for voltage controlled and restrained overcurrent protection, pick-up setting is ‘V Dep OC I> Set x V Dep OC k Set’ dependent on the voltage level.				
Z<1 Setting	34	30	70*V1/In	2*V1/In to 120*V1/In step 0.5*V1/In
Pick-up impedance setting for first stage underimpedance protection.				
Z<1 Time Delay	34	31	5 s	0 s to 100 s step 10 ms
Operating time-delay setting of the first stage underimpedance protection.				
Z<1 tRESET	34	32	0 s	0 s to 100 s step 10 ms
Reset/release time setting for the first stage underimpedance protection.				
Z< Stage2	34	33	Disabled	Disabled or Enabled
Enables or disables the second stage underimpedance function.				
Z<2 Setting	34	34	70*V1/In	2*V1/In to 120*V1/In step 0.5*V1/In
Pick-up impedance setting for second stage underimpedance protection.				
Z<2 Time Delay	34	35	5 s	0 s to 100 s step 10 ms
Operating time-delay setting of the second stage underimpedance protection				
Z<2 tRESET	34	36	0 s	0 s to 100 s step 10 ms
Reset/release time setting for the second stage underimpedance protection.				

Table 6 - System backup protection settings

4.6 Phase Overcurrent Protection (50/51/67/46OC)

The overcurrent protection included in the relay 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.

The overcurrent protection menu also includes settings for four stages of non-directional / directional Negative Phase Sequence (NPS) overcurrent protection with independent definite time delay characteristics.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 OVERCURRENT	35	00		
GROUP 1 OVERCURRENT				
PHASE O/C	35	20		
I> CT Source	35	21	IA-1 IB1-1 IC-1	0 = IA1-1 IB-1 IC-1, 1 =IA1-2 IB-2 IC-2
This setting is used to select the 3-phase current inputs used by the Phase Overcurrent elements in the P343/P344/P345 - IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 CT inputs.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
I>1 Function	35	23	IEC S Inverse	Disabled, DT, IEC S Inverse, IEC V Inverse, IEC E Inverse, UK LT Inverse, Rectifier, RI, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse
Tripping characteristic for the first stage overcurrent protection.				
I>1 Direction	35	24	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the first stage overcurrent protection.				
I>1 Current Set	35	27	1*In	0.08*In to 4.0*In step 0.01*In
Pick-up setting for first stage overcurrent protection.				
I>1 Time Delay	35	29	1 s	0 s to 100 s step 10 ms
Operating time-delay setting for the definite time setting if selected for first stage element.				
I>1 TMS	35	2A	1	0.025 to 1.2 step 0.025
Time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
I>1 Time Dial	35	2B	1	0.01 to 100 step 0.01
Time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
I>1 K (RI)	35	2C	1	0.1 to 10 step 0.05
Time multiplier setting to adjust the operating time for the RI curve.				
I>1 Reset Char	35	2E	DT	0 = DT, 1 = Inverse
Type of reset/release characteristic of the IEEE/US curves.				
I>1 tRESET	35	2F	0 s	0 s to 100 s step 10 ms
Reset/release time setting for definite time reset characteristic.				
I>2 Function	35	32	Disabled	0=Disabled, 1=DT, IEC S Inverse, IEC V Inverse, IEC E Inverse, UK LT Inverse, Rectifier, RI, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse
Tripping characteristic for the second stage overcurrent protection.				
I>2 Direction	35	33	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the second stage overcurrent protection.				
I>2 Current Set	35	36	1*In	0.08*In to 4.0*In step 0.01*In
Pick-up setting for second stage overcurrent protection.				
I>2 Time Delay	35	38	1 s	0 s to 100 s step 10 ms
Operating time-delay setting for the definite time setting if selected for second stage element.				
I>2 TMS	35	39	1	0.025 to 1.2 step 0.025
Time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
I>2 Time Dial	35	3A	1	0.01 to 100 step 0.01
Time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
I>2 K (RI)	35	3B	1	0.1 to 10 step 0.05
Time multiplier setting to adjust the operating time for the RI curve.				
I>2 Reset Char	35	3D	DT	0 = DT, 1 = Inverse
Type of reset/release characteristic of the IEEE/US curves.				
I>2 tRESET	35	3E	0 s	0 s to 100 s step 10 ms
Reset/release time setting for definite time reset characteristic.				
I>3 Status	35	40	Disabled	Disabled or Enabled
Enable or disables the third stage overcurrent protection.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
I>3 Direction	35	41	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the third stage overcurrent protection.				
I>3 Current Set	35	44	10*In	0.08*In to 10*In step 0.01*In
Pick-up setting for third stage overcurrent protection.				
I>3 Time Delay	35	45	0 s	0 s to 100 s step 10 ms
Operating time-delay setting for third stage overcurrent protection.				
I>4 Status	35	47	Disabled	Disabled or Enabled
Enable or disables the fourth stage overcurrent protection.				
I>4 Direction	35	48	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the fourth stage overcurrent protection.				
I>4 Current Set	35	4B	10*In	0.08*In to 10*In step 0.01*In
Pick-up setting for fourth stage overcurrent protection.				
I>4 Time Delay	35	4C	0 s	0 s to 100 s step 10 ms
Operating time-delay setting for fourth stage overcurrent protection.				
I> Char Angle	35	4E	30 °	-95 ° to 95 ° step 1 °
Relay characteristic angle setting used for the directional decision.				
I> Function Link	35	4F	1111(bin)	Bit 00 = I>1 VTS Block, Bit 01 = I>2 VTS Block, Bit 02 = I>3 VTS Block, Bit 03 = I>4 VTS Block
Logic Settings that determine whether blocking signals from VT supervision 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.				
NPS OVERCURRENT	35	50		
I2> CT Source	35	51	IA-1 IB1-1 IC-1	0 = IA1-1 IB-1 IC-1, 1 =IA1-2 IB-2 IC-2
This setting is used to select the 3-phase current inputs used by the Negative Sequence Overcurrent elements in the P343/P344/P345 - IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 CT inputs.				
I2>1 Status	35	52	Disabled	Disabled or Enabled
Enables or disables the first stage negative phase sequence overcurrent protection.				
I2>1 Directional	35	54	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the negative phase sequence overcurrent element.				
I2>1 Current Set	35	56	0.2*In	0.08*In to 4*In step 0.01*In
Pick-up setting for the first stage negative phase sequence overcurrent protection.				
I2>1 Time Delay	35	58	10 s	0 s to 100 s step 10 ms
Operating time-delay setting for the first stage negative phase sequence overcurrent protection.				
I2>2 Status	35	62	Disabled	Disabled or Enabled
Enables or disables the second stage negative phase sequence overcurrent protection.				
I2>2 Directional	35	64	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the negative phase sequence overcurrent element.				
I2>2 Current Set	35	66	0.2*In	0.08*In to 4*In step 0.01*In
Pick-up setting for the second stage negative phase sequence overcurrent protection.				
I2>2 Time Delay	35	68	10 s	0 s to 100 s step 10 ms

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Operating time-delay setting for the second stage negative phase sequence overcurrent protection.				
I2>3 Status	35	72	Disabled	Disabled or Enabled
Enables or disables the third stage negative phase sequence overcurrent protection.				
I2>3 Directional	35	74	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the negative phase sequence overcurrent element.				
I2>3 Current Set	35	76	0.2*In	0.08*In to 4*In step 0.01*In
Pick-up setting for the third stage negative phase sequence overcurrent protection.				
I2>3 Time Delay	35	78	10 s	0 s to 100 s step 10 ms
Operating time-delay setting for the third stage negative phase sequence overcurrent protection.				
I2>4 Status	35	82	Disabled	Disabled or Enabled
Enables or disables the fourth stage negative phase sequence overcurrent protection.				
I2>4 Directional	35	84	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of the negative phase sequence overcurrent element.				
I2>4 Current Set	35	86	0.2*In	0.08*In to 4*In step 0.01*In
Pick-up setting for the fourth stage negative phase sequence overcurrent protection.				
I2>4 Time Delay	35	88	10 s	0 s to 100 s step 10 ms
Operating time-delay setting for the fourth stage negative phase sequence overcurrent protection.				
I2> VTS Blocking	35	90	1111(bin)	Bit 00 = VTS Blocks I2>1, Bit 01 = VTS Blocks I2>2, Bit 02 = VTS Blocks I2>3, Bit0 3 = VTS Blocks I2>4
Logic settings that determine whether VT supervision blocks selected negative phase sequence overcurrent stages. 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.				
I2> Char Angle	35	94	-60 °	-95 ° to 95 ° step 1 °
Relay characteristic angle setting used for the directional decision.				
I2> V2Pol Set	35	98	5*V1	0.5*V1 to 25*V1 step 0.5*V1
Minimum negative phase sequence voltage polarizing quantity for directional decision.				

Table 7 - Phase overcurrent protection settings

4.7 Thermal Overload (49)

The thermal overload function within the relay is a single time constant thermal trip characteristic, dependent on the type of plant to be protected. It also includes a definite time alarm stage.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 THERMAL OVERLOAD	36	00		
GROUP 1 THERMAL OVERLOAD				
GEN THERMAL	36	40		
Thermal	36	50	Enabled	Disabled or Enabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Enables or disables the Generator Thermal Overload trip function.				
Thermal I>	36	55	1.2*In	0.5*In to 2.5*In step 0.01*In
Pick-up setting for thermal overload trip.				
Thermal Alarm	36	5A	90%	20% to 100% step 1%
Thermal state pick-up setting corresponding to a percentage of the trip threshold at which an alarm will be generated.				
T-heating	36	5F	1 mins	1 mins to 200 mins step 1 mins
Heating thermal time constant setting for the thermal overload characteristic.				
T-cooling	36	64	1 mins	1 mins to 200 mins step 1 mins
Cooling thermal time constant setting for the thermal overload characteristic.				
M Factor	36	69	0	0 to 10 step 1
The M factor setting is a constant that relates negative phase sequence current heating to positive sequence current heating, Ieq = (I12 + M I22) 0.5				
XFORMER THERMAL	36	70		
Thermal	36	71	Enabled	Disabled or Enabled
Enables or disables the transformer Thermal Overload trip function.				
Mn't winding	36	72	HV Current	HV Current, LV Current, Biased Current
Monitored winding – HV current or LV current or Bias current. Bias current = (HV current + LV current)/2. The through load current of the transformer is monitored when the monitor winding is set to Biased Current. (P343/P344/P345)				
Ambient T	36	73	AVERAGE	RTD 1 to 10, CLIO1 to 4, AVERAGE
The ambient temperature may be a setting (Average) or it may be measured using RTD or CLIO inputs.				
Amb CLI Type	36	74	4-20mA	0-1 mA, 0-10 mA, 0-20 mA, 4-20 mA
Ambient temperature current loop input type. This setting is available when Ambient T is set to CLIOx.				
Amb CLI Min	36	75	0	-9999 to 9999 step 0.1
Ambient temperature current loop input minimum setting. Defines the lower range of the ambient temperature measured by the transducer. This setting is available when Ambient T is set to CLIOx.				
Amb CLI Max	36	76	100	-9999 to 9999 step 0.1
Ambient temperature current loop input maximum setting. Defines the upper range of the ambient temperature measured by the transducer. This setting is available when Ambient T is set to CLIOx.				
Average Amb T	36	77	25 °C	-25 °C to 75 °C step 0.1 °C
Average ambient temperature. This setting is available when Ambient T is set to Average.				
Top Oil T	36	78	CALCULATED	RTD 1 to 10, CLIO1 to 4, CALCULATED
The top oil temperature may be calculated by the relay, or it may be measured using RTD or CLIO inputs.				
Top Oil CLI Typ	36	79	4-20mA	0-1 mA, 0-10 mA, 0-20 mA, 4-20 mA
Top oil current loop input type. This setting is available when Top Oil T is set to CLIOx.				
Top Oil CLI Min	36	7A	0	-9999 to 9999 step 0.1
Top oil temperature current loop input minimum setting. Defines the lower range of the top oil temperature measured by the transducer. This setting is available when Top Oil T is set to CLIOx.				
Top Oil CLI Max	36	7B	100	-9999 to 9999 step 0.1
Top oil temperature current loop input maximum setting. Defines the upper range of the top oil temperature measured by the transducer. This setting is available when Top Oil T is set to CLIOx.				
IB	36	7C	1 PU	0.1 PU to 4 PU step 0.01 PU
IB is the load in pu. It is recommended to set it to the rated load, of 1.0 pu. The relay uses this setting to calculate the ratio of ultimate load to rated load.				
Rated NoLoadLoss	36	7D	3	0.1 to 100 step 0.1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Ratio of load loss at rated load to no-load loss (iron loss). The transformer manufacturer should provide this parameter.				
Hot Spot overtop	36	7E	25 °C	0.1 °C to 200 °C step 0.1 °C
Hottest spot temperature over top oil temperature setting. The transformer manufacturer should provide this parameter.				
Top Oil overamb	36	7F	55 °C	0.1 °C to 200 °C step 0.1 °C
Top oil temperature over ambient temperature setting. The transformer manufacturer should provide this parameter.				
Cooling Mode	36	80	Natural	Natural, Forced Air, Forced Oil, Forced Air & Oil, Select via PSL
This setting specifies which kind of cooling mode is used to cool the transformer. If Select Via PSL then DDB inputs (650 Frcd Air Cool and 651 Frcd Oil Cool) can be used to select the cooling mode Winding exp m and oil exp n settings, as below. If DDB 650 = 1 then cooling mode is Forced Air Cooling, if DDB 651 = 1 then cooling mode is Forced Oil Cooling, if DDB 650 and 651 = 1 then cooling mode is Forced Air & Oil Cooling, if DDB 650 and 651 = 0 then cooling mode is Natural Cooling.				
Cooling Status	36	81		Not Settable
Cooling Status indication; it is visible only when Cooling Mode is set as 'Select via PSL'. If DDB 650 = 1 then cooling status is Forced Air Cooling, if DDB 651 = 1 then cooling status is Forced Oil Cooling, if DDB 650 and 651 = 1 then cooling status is Forced Air & Oil Cooling, if DDB 650 and 651 = 0 then cooling status is Natural Cooling.				
NATURAL COOL	36	82		
Winding exp m	36	83	0.8	0.01 to 2 step 0.01
Winding exponent constant used to calculate the ultimate hot spot rise temperature over top oil temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
Oil exp n	36	84	0.8	0.01 to 2 step 0.01
Oil exponent constant used to calculate the ultimate top oil rise temperature over ambient temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
FORCED AIR COOL	36	85		
Winding exp m	36	86	0.8	0.01 to 2 step 0.01
Winding exponent constant used to calculate the ultimate hot spot rise temperature over top oil temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
Oil exp n	36	87	0.8	0.01 to 2 step 0.01
Oil exponent constant used to calculate the ultimate top oil rise temperature over ambient temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
FORCED OIL COOL	36	88		
Winding exp m	36	89	0.8	0.01 to 2 step 0.01
Winding exponent constant used to calculate the ultimate hot spot rise temperature over top oil temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
Oil exp n	36	8A	0.8	0.01 to 2 step 0.01
Oil exponent constant used to calculate the ultimate top oil rise temperature over ambient temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
FORCED AIR & OIL	36	8B		
Winding exp m	36	8C	0.8	0.01 to 2 step 0.01

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Winding exponent constant used to calculate the ultimate hot spot rise temperature over top oil temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
Oil exp n	36	8D	0.8	0.01 to 2 step 0.01
Oil exponent constant used to calculate the ultimate top oil rise temperature over ambient temperature. Recommended values are provided in IEEE Std. C57.91-1995 (see the Application Notes chapter for recommended values), or can be provided by the transformer manufacturer.				
Hot spot rise co	36	8E	1 mins	0.01 mins to 20 mins step 0.01 mins
Winding time constant setting. The transformer manufacturer should provide this parameter.				
Top oil rise co	36	8F	120 mins	1 mins to 1000 mins step 1 mins
Oil time constant setting. The transformer manufacturer should provide this parameter.				
TOL Status	36	90	Enabled	Disabled or Enabled
This setting enables or disables the three hot spot and the three top oil thermal stages.				
Hot Spot>1 Set	36	91	110	1 to 300 step 0.1
Hot spot first stage setting. Recommended temperature limits are given in IEEE Std. C57.91-1995. See the Application Notes chapter for recommended values.				
tHot Spot>1 Set	36	92	10 mins	0 mins to 60000 mins step 1 mins
Hot spot first stage time delay setting.				
Hot Spot>2 Set	36	93	130	1 to 300 step 0.1
Hot spot second stage setting. Recommended temperature limits are given in IEEE Std. C57.91-1995. See the Application Notes chapter for recommended values.				
tHot Spot>2 Set	36	94	10 mins	0 mins to 60000 mins step 1 mins
Hot spot second stage time delay setting.				
Hot Spot>3 Set	36	95	150	1 to 300 step 0.1
Hot spot third stage setting. Recommended temperature limits are given in IEEE Std. C57.91-1995. See the Application Notes chapter for recommended values.				
tHot Spot>3 Set	36	96	10 mins	0 mins to 60000 mins step 1 mins
Hot spot third stage time delay setting.				
Top Oil>1 Set	36	97	70	1 to 300 step 0.1
Top oil first stage setting. Recommended temperature limits are given in IEEE Std. C57.91-1995. See the Application Notes chapter for recommended values.				
tTop Oil>1 Set	36	98	10 mins	0 mins to 60000 mins step 1 mins
Top oil first stage time delay setting.				
Top Oil>2 Set	36	99	80	1 to 300 step 0.1
Top oil second stage setting. Recommended temperature limits are given in IEEE Std. C57.91-1995. See the Application Notes chapter for recommended values.				
tTop Oil>2 Set	36	9A	10 mins	0 mins to 60000 mins step 1 mins
Top oil second stage time delay setting.				
Top Oil>3 Set	36	9B	90	1 to 300 step 0.1
Top oil third stage setting. Recommended temperature limits are given in IEEE Std. C57.91-1995. See the Application Notes chapter for recommended values.				
tTop Oil>3 Set	36	9C	10 mins	0 mins to 60000 mins step 1 mins
Top oil third stage time delay setting.				
tPre-trip Set	36	9D	5 mins	0 mins to 60000 mins step 1 mins
A pre-trip alarm is given a set time before the top oil and hot spot trips using this setting, assuming that the load remains unchanged.				
LOL Status	36	A0	Enabled	Disabled or Enabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Enables or disables the loss of life function				
Life Hours at HS	36	A1	180000	1 to 300000 step 1
Life hours at the reference hottest spot temperature. Advice from the transformer manufacturer may be required.				
Design HS temp	36	A2	110	1 to 200 step 0.1
The designed hottest spot temperature is 110°C for a transformer rated 65°C average winding rise, and 95°C for a transformer rated 55°C average winding rise.				
Constant B Set	36	A3	15000	1 to 100000 step 1
Constant B is associated to the life expectancy curve. It is based on modern experimental data, and it may be set to 15000 as recommended by IEEE Std. C57.91-1995.				
FAA> Set	36	A4	2	0.1 to 30 step 0.01
Aging acceleration factor setting. If the aging acceleration factor calculated by the relay is above this setting and tFAA has expired, an FAA alarm would be asserted. FAA calculation depends on constant B and the hottest temperature calculated by the thermal element.				
tFAA> Set	36	A5	10	0 to 60000 step 1
Aging acceleration factor timer.				
LOL>1 Set	36	A6	160000	1 to 300000 step 1
Transformer loss of life setting. If the life already lost by the transformer is above this threshold, a LOL alarm would be asserted after tLOL has expired. LOL calculation depends on the life hours at design hot spot temperature and the calculated residual life.				
tLOL> Set	36	A7	10	0 to 60000 step 1
Loss of life timer.				
Reset Life Hours	36	B0	0	0 to 300000 step 1
Resets the LOL status value to the set value when the loss of life reset command is executed. For new transformers Reset Life Hours is zero, so that when the commissioning of the thermal element is over, the loss of life statistics calculations are reset to zero. For old transformers this setting should indicate how much life the transformer has already lost; therefore, it should be set to the transformer loss of life.				

Table 8 - Thermal overload protection settings

4.8 Generator and Transformer - Differential Protection

The generator differential protection in the P343/P344/P345 relay may be configured to operate as either a high impedance or biased differential element. The same current inputs as used by the high impedance protection can also be used for interturn protection.

The P343/P344/P345 also includes a biased differential generator-transformer protection with two high set elements.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 DIFFERENTIAL	37	00		
GROUP 1 DIFFERENTIAL				
GEN DIFF	37	01		
Generator Diff settings are visible if SYSTEM CONFIG - Winding Type = Generator Diff				
Gen Diff Func	37	02	Percentage Bias	0 = Disabled, 1 = Percentage Bias, 2 = High Impedance, 3 = Interturn
Setting to select the function of the differential protection element.				
Gen Diff Is1	37	03	0.1*In	0.05*In to 0.5*In step 0.01*In

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Minimum differential operating current of the low impedance biased characteristic. Also, the pick-up setting of the high impedance differential protection.				
Gen Diff k1	37	04	0%	0% to 20% step 5%
Slope angle setting for the first slope of the low impedance biased characteristic.				
Gen Diff Is2	37	05	1.2*In	1*In to 5*In step 0.1*In
The bias current operating threshold for the second slope low impedance characteristic.				
Gen Diff k2	37	06	1.5	20% to 150% step 10%
Slope angle setting for the second slope of the low impedance biased characteristic				
Interturn Is_A	37	10	0.1*In	0.05*In to 2*In step 0.01*In
Pick-up setting for the A phase interturn overcurrent element.				
Interturn Is_B	37	14	0.1*In	0.05*In to 2*In step 0.01*In
Pick-up setting for the B phase interturn overcurrent element.				
Interturn Is_C	37	18	0.1*In	0.05*In to 2*In step 0.01*In
Pick-up setting for the C phase interturn overcurrent element.				
Interturn Delay	37	1C	100 ms	0 s to 100 s step 10 ms
Operating time-delay setting of the interturn protection.				
XFORMER DIFF	37	30		
XFORMER DIFF settings are visible if SYSTEM CONFIG - Winding Type = Xformer Diff				
Xform Diff Func	37	31	Enabled	Disabled or Enabled
Enables or disables the transformer differential function.				
Set Mode	37	32	Simple	Simple or Advanced
If the relay is in Simple mode, zero sequence filtering (Zero seq filt HV/LV) is enabled automatically when the cell HV/LV Grounding under the SYSTEM CONFIG menu heading is set to grounded. If the relay is in advanced mode, the zero sequence filtering is enabled or disabled manually in the cell Zero seq filt HV/LV under the DIFFERENTIAL menu heading. Also, in the simple mode the relay calculates automatically Xform Is-HS1 as 1/Xt, where Xt is the transformer reactance, Xt = %Reactance setting in the SYSTEM CONFIG menu. In Simple mode under the DIFF PROTECTION menu heading the cells Zero seq filt HV/LV, Xform Is-HS1 and Xform Is-Hs2 are Read Only.				
Xform Is1	37	33	0.2 PU	0.05 PU to 2.5 PU step 0.01 PU
Minimum differential threshold of the low set differential characteristic.				
Xform k1	37	34	30%	0% to 150% step 1%
Slope angle setting for the first slope of the low impedance biased characteristic.				
Xform Is2	37	35	1 PU	0.1 PU to 10 PU step 0.1 PU
Bias current threshold for the second slope of the low set differential characteristic.				
Xform k2	37	36	80%	15% to 150% step 1%
Slope angle setting for the second slope of the low impedance biased characteristic.				
Xform tDiff	37	37	0 s	0 s to 10 s step 10 ms
Bias differential time delay				
Xform Is-CTS	37	40	1.5 PU	0.1 PU to 2.5 PU step 0.01 PU
In restrain mode, the differential protection Is1 setting is increased to Is-CTS setting after a CT failure is detected. The Is-CTS setting increases the restrain region of the differential characteristic.				
Xform HS1 Status	37	41	Enabled	Disabled or Enabled
This enables or disables generator-transformer high set 1 protection.				
Xform Is-HS1	37	42	10 PU	2.5 PU to 16 PU step 0.1 PU

Courier Text	Col	Row	Default Setting	Available Setting
Description				
High set element one. In the simple mode the relay uses the %Reactance in the SYSTEM CONFIG menu to calculate Xform Is-HS1 as 1/Xt. Where Xt is the transformer reactance. This setting is Read Only in simple mode. In advance mode Xform Is-HS1 is visible and settable. The high set 1 algorithm uses a peak detection method to achieve fast operating times. Above the adjustable differential current threshold Xform Is-HS1, the P34x will trip without taking into account either the second or fifth harmonic blocking but the bias current is considered.				
Xform HS2 Status	37	43	Enabled	Disabled or Enabled
This enables or disables generator-transformer high set 2 protection.				
Xform Is-HS2	37	44	16 PU	2.5 PU to 16 PU step 0.1 PU
High set element two. This element is settable and visible in advance mode. In simple mode, it is Read Only and set to 16 pu. The Is-HS2 element uses the fundamental component of the differential current. This element is not restrained by the bias characteristic, so the P34x will trip regardless of the restraining current. Above the adjustable differential current threshold Xform Is-HS2, the P34x will trip without taking into account either the second or fifth harmonic blocking or the bias current.				
Zero seq filt HV	37	50	Enabled	Disabled or Enabled
Enables or disables zero sequence filtering on the HV winding. This setting is only visible and settable in advance mode.				
Zero seq filt LV	37	51	Enabled	Disabled or Enabled
Enables or disables zero sequence filtering on the LV winding. This setting is only visible and settable in advance mode.				
2nd harm blocked	37	52	Enabled	Disabled or Enabled
Enables or disables 2nd harmonic blocking.				
Xform Ih(2)%>	37	53	0.2	5% to 50% step 1%
Second harmonic blocking threshold.				
Cross blocking	37	54	Disabled	Disabled or Enabled
Enables or disables cross blocking. Second harmonic blocking is enabled across all three phases if cross blocking is selected and the second harmonic blocking threshold is exceeded in any phase.				
5th harm blocked	37	55	Disabled	Disabled or Enabled
Enables or disables 5th harmonic blocking.				
Xform Ih(5)%>	37	56	0.35	0% to 100% step 1%
Fifth harmonic blocking threshold. Fifth harmonic blocking is per phase, no cross blocking is available.				
Circuitry Fail	37	60	Enabled	Disabled or Enabled
Enables or disables the circuitry fail alarm.				
Is-cctfail	37	61	0.1 PU	0.03 PU to 1 PU step 0.1 PU
Minimum differential threshold of the circuitry fail alarm.				
K-cctfail	37	62	0.1	0% to 50% step 1%
Slope angle setting for the circuitry fail alarm function.				
CctFail Delay	37	63	5 s	0 s to 10 s step 100 ms
Circuitry fail alarm time delay.				

Table 9 - Generator protection and generator-transformer differential settings

4.9 Earth Fault (50N/51N)

The earth fault protection included in the relay provides two-stage non-directional earth fault protection. The first stage of earth fault protection has time-delayed characteristics which are selectable between IDMT, or DT. The second stage has a DT characteristic only.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 EARTH FAULT	38	00		
GROUP 1 EARTH FAULT				
IN> Input	38	01	Measured	
Shows the input used for the Earth Fault element				
IN>1 Function	38	25	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
Tripping characteristic for the first stage earth fault protection.				
IN>1 Current	38	29	0.1*I2	0.02*I2 to 4*I2 step 0.01*I2
Pick-up setting for the first stage earth fault protection.				
IN>1 IDG Is	38	2A	1.5	1 to 4 step 0.1
Multiple of “IN>” setting for the IDG curve (Scandinavian) and determines the actual relay current threshold at which the element starts.				
IN>1 Time Delay	38	2C	1 s	0 s to 200 s step 10 ms
Operating time-delay setting for the first stage definite time element.				
IN>1 TMS	38	2D	1	0.025 to 1.2 step 0.025
Time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
IN>1 Time Dial	38	2E	1	0.01 to 100 step 0.01
Time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
IN>1 K (RI)	38	2F	1	0.1 to 10 step 0.05
Time multiplier to adjust the operating time for the RI curve.				
IN>1 IDG Time	38	30	1.2	1 to 2 step 0.01
Minimum operating time at high levels of fault current for IDG curve.				
IN>1 Reset Char	38	32	DT	0 = DT, 1 = Inverse
Type of reset/release characteristic of the IEEE/US curves.				
IN>1 tRESET	38	33	0 s	0 s to 100 s step 10 ms
Reset/release time for definite time reset characteristic.				
IN>2 Function	38	36	Disabled	0 = Disabled, 1 = DT
Tripping characteristic for the second stage earth fault element.				
IN>2 Current	38	3A	0.45*I2	0.02*I2 to 10*I2 step 0.01*I2
Pick-up setting for second stage earth fault protection.				
IN>2 Time Delay	38	3D	0 s	0 s to 200 s step 10 ms
Operating time delay setting for the second stage earth fault protection.				

Table 10 - Earth fault protection settings

4.10 Rotor Earth Fault (64R)

Rotor earth fault protection is provided by the P391 low frequency square wave injection, coupling and measurement unit connected to the rotor circuit. The measurement of the rotor resistance is passed to the relay via a current loop output (0-20 mA) on the P391 connected to one of the 4 current loop inputs on the relay. The rotor ground fault protection is only available if the relay includes the CLIO hardware option.

The rotor earth fault protection in the relay includes 2 stages of under resistance protection. The under resistance protection is designed as a two stage protection system, one alarm stage (64R R<1) and one trip stage (64R R<2), with each stage having a definite time delay setting. The injection frequency is selectable 0.25/0.5/1 Hz via a jumper link in the P391.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 ROTOR EF	39	00		
GROUP 1 ROTOR EF				
Injection Freq	39	02	0.25 Hz	0 = 0.25Hz, 1 = 0.5Hz, 2 = 1.0Hz
Injection frequency. Must be equal to injection frequency set on P391.				
CL I/P Select	39	04	CL1	CL1, CL2, CL3, CL4
Current Loop Input used for the rotor earth fault protection.				
64R R<1 Alarm	39	08	Enabled	Disabled or Enabled
Enables or disables the first stage under resistance element.				
64R R<1 Alm Set	39	0C	40000 Ω	1000 Ω to 80000 Ω step 1 Ω
Pick-up setting for the first stage under resistance element.				
64R R<1 Alm Dly	39	10	10 s	0 s to 600 s step 100 ms
Operating time-delay setting of the first stage under resistance element.				
64R R<2 Trip	39	14	Enabled	Disabled or Enabled
Enables or disables the second stage under resistance trip element.				
64R R<2 Trip Set	39	18	5000 Ω	1000 Ω to 80000 Ω step 1 Ω
Pick-up setting for the second stage under resistance element.				
64R R<2 Trip Dly	39	1C	1 s	0 s to 600 s step 100 ms
Operating time-delay setting of the second stage under resistance trip element.				
R Compensation	39	20	0 Ω	-1000 Ω to 1000 Ω step 1 Ω
Resistance compensation setting.				

Table 11 - Rotor earth fault protection settings

4.11 Sensitive Earth Fault / Restricted Earth Fault (50N/51N/67N/67W/64)

If a system is earthed through a high impedance, or is subject to high ground fault resistance, the earth fault 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 single-stage sensitive earth fault element is provided within the relay for this purpose, which has a dedicated input.

This input may be configured to be used as a 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 sensitive current input as the SEF protection and sensitive power protection. Hence, only one of these elements may be selected. However, the low impedance REF element can be used in conjunction with the SEF protection.*

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 SEF/REF PROT'N	3A	00		
GROUP 1 SEF/REF PROT'N				
SEF/REF Options	3A	01	SEF	SEF, SEF cos, SEF sin, Wattmetric, Hi Z REF, Lo Z REF, Lo Z REF+SEF, Lo Z REF+Wattmet
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	3A	2A	DT	0 = Disabled, 1 = DT
Tripping characteristic for the first stage sensitive earth fault element.				
ISEF>1 Direction	3A	2B	Non-Directional	0 = Non-Directional, 1 = Directional Fwd, 2 = Directional Rev
Direction of measurement for the first stage sensitive earth fault element.				
ISEF>1 Current	3A	2E	0.05*I3	0.005*I3 to 0.1*I3 step 0.00025*I3
Pick-up setting for the first stage sensitive earth fault element.				
ISEF>1 Delay	3A	31	1 s	0 s to 200 s step 10 ms
Operating time delay setting for the first stage definite time element.				
ISEF> Func Link	3A	57	0001(bin)	Bit 00 = ISEF>1 VTS Block, Bits 01 - 03 are not used
Setting that determines whether VT supervision logic signals blocks the sensitive earth fault stage. 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.				
ISEF> Char Angle	3A	59	90 °	-95 ° to 95 ° step 1 °
Relay characteristic angle used for the directional decision.				
ISEF>VNpol Input	3A	5A	Measured	0 = Measured, 1 = Derived
Residual/neutral voltage polarization source.				
ISEF> VNpol Set	3A	5B	5*V1	0.5*V1 to 80*V1 step 0.5*V1
Minimum residual/neutral voltage polarizing quantity required for the directional decision.				
WATTMETRIC SEF	3A	5D		
PN> Setting	3A	5E	9*V1*I3	0 to 20*V1*I3 step 0.05*V1*I3
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 (phi - phic) = 9 x Vo x Io x Cos (phi - phic) Where: phi = Angle between the Polarizing Voltage (-Vres) and the Residual Current phic = Relay Characteristic Angle (RCA) Setting (ISEF> Char Angle) Vres = Residual Voltage Ires = Residual Current Vo = Zero Sequence Voltage Io = Zero Sequence Current				

Table 12 - Sensitive earth fault protection settings

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

Courier Text	Col	Row	Default Setting	Available Setting
Description				
RESTRICTED E/F	3A	60		
REF is a Restricted Earth Fault.				
IREF> CT Source	3A	61	IA-1 IB-1 IC-1	IA-1 IB-1 IC-1 or IA-2 IB-2 IC-2
This setting is used to select the 3-phase current inputs used by the Restricted Earth Fault protection in the P343/P344/P345 - IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 CT inputs.				
IREF> k1	3A	62	0	0% to 20% step 1%
Slope angle setting for the first slope of the low impedance biased characteristic.				
IREF> k2	3A	63	150%	0% to 150% step 1%
Slope angle setting for the second slope of the low impedance biased characteristic.				
IREF> Is1	3A	64	0.2*In	0.05*In to 1.0*In step 0.01*In
Minimum differential operating current for the low impedance characteristic.				
IREF> Is2	3A	65	1*In	0.1*In to 1.5*In step 0.01*In
Bias current operating threshold for the second slope low impedance characteristics.				
IREF> Is	3A	66	0.2*I3	0.05*I3 to 1.0*I3 step 0.01*I3
Pick-up setting for the high impedance REF protection.				

Table 13 - Restricted earth fault protection settings

4.12 Residual Overvoltage (Neutral Voltage Displacement) (59N)

The Neutral Voltage Displacement (NVD) element within the relay is of four-stage design for P342/P343 and six-stage for P344/P345, each stage having separate voltage and time delay settings. All stages may be set to operate on either an IDMT or DT characteristic. Stages 1 & 2 used a voltage derived from the summation of the phase voltages. Stages 3 & 4 use the VN1 input measurement. This input is also used for check synch on P342 and P343 so both functions cannot be used simultaneously. Stages 5& 6 use the VN2 input. Again this input is shared with the check synch on the P344 meaning both functions cannot be used simultaneously.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 RESIDUAL O/V NVD	3B	00		
GROUP 1 RESIDUAL O/V NVD				
VN>1 Status	3B	10	Enabled	Disabled or Enabled
Enables or disables the VN>1 trip stage.				
VN>1 Input	3B	12	Derived	0 = Derived, 1 = VN1, 2 = VN2
VN>1 uses derived neutral voltage from the 3 phase voltage input (VN = VA+VB+VC).				
VN>1 Function	3B	14	DT	DT, IDMT
Tripping characteristic setting of the first stage residual overvoltage element.				
VN>1 Voltage Set	3B	16	5*V1	1*V1 to 80*V1 step 1*V1
Pick-up setting for the first stage residual overvoltage characteristic.				
VN>1 Time Delay	3B	18	5 s	0 s to 100 s step 10 ms
Operating time delay setting for the first stage definite time residual overvoltage element.				
VN>1 TMS	3B	1A	1	0.5 to 100 step 0.5

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 tReset	3B	1C	0 s	0 s to 100 s step 10 ms
Reset/release definite time setting for the first stage characteristic.				
VN>2 Status	3B	20	Disabled	Disabled or Enabled
Enables or disables the second stage residual overvoltage element.				
VN>2 Input	3B	22	Derived	0 = Derived, 1 = VN1, 2 = VN2
VN>2 uses derived neutral voltage from the 3 phase voltage input (VN = VA+VB+VC).				
VN>2 Function	3B	24	DT	0 = Disabled, 1 = DT, 2 = IDMT
Tripping characteristic setting of the second stage residual overvoltage element.				
VN>2 Voltage Set	3B	26	5*V1	1*V1 to 80*V1 step 1*V1
Pick-up setting for the second stage residual overvoltage characteristic.				
VN>2 Time Delay	3B	28	10 s	0 s to 100 s step 10 ms
Operating time delay setting for the second stage definite time residual overvoltage element.				
VN>2 TMS	3B	2A	1	0.5 to 100 step 0.5
Time multiplier setting to adjust the operating time of the IDMT characteristic. The characteristic is defined as above				
VN>2 tReset	3B	2C	0 s	0 s to 100 s step 10 ms
Reset/release definite time setting for the second stage characteristic.				
VN>3 Status	3B	30	Enabled	Disabled or Enabled
Enables or disables the third stage residual overvoltage element.				
VN>3 Input	3B	32	VN1	0 = Derived, 1 = VN1, 2 = VN2
VN>3 uses measured neutral voltage from the VNeutral/VN1 input.				
VN>3 Function	3B	34	DT	0 = Disabled, 1 = DT, 2 = IDMT
Tripping characteristic setting of the third stage residual overvoltage element.				
VN>3 Voltage Set	3B	36	5*V1	1*V1 to 80*V1 step 1*V1
Pick-up setting for the third stage residual overvoltage characteristic.				
VN>3 Time Delay	3B	38	5 s	0 s to 100 s step 10 ms
Operating time delay setting for the third stage definite time residual overvoltage element.				
VN>3 TMS	3B	3A	1	0.5 to 100 step 0.5
Time multiplier setting to adjust the operating time of the IDMT characteristic. The characteristic is defined as above				
VN>3 tReset	3B	3C	0 s	0 s to 100 s step 10 ms
Reset/release definite time setting for the third stage characteristic.				
VN>4 Status	3B	40	Disabled	Disabled or Enabled
Enables or disables the fourth stage residual overvoltage element.				
VN>4 Input	3B	42	VN1	0 = Derived, 1 = VN1, 2 = VN2
VN>4 uses measured neutral voltage from the VNeutral/VN1 input.				
VN>4 Function	3B	44	DT	0 = Disabled, 1 = DT, 2 = IDMT
Tripping characteristic setting of the fourth stage residual overvoltage element.				
VN>4 Voltage Set	3B	46	5*V1	1*V1 to 80*V1 step 1*V1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Pick-up setting for the fourth stage residual overvoltage characteristic.				
VN>4 Time Delay	3B	48	10 s	0 s to 100 s step 10 ms
Operating time delay setting for the fourth stage definite time residual overvoltage element.				
VN>4 TMS	3B	4A	1	0.5 to 100 step 0.5
Time multiplier setting to adjust the operating time of the IDMT characteristic. The characteristic is defined as above				
VN>4 tReset	3B	4C	0 s	0 s to 100 s step 10 ms
Reset/release definite time setting for the fourth stage characteristic.				
VN>5 Status	3B	50	Enabled	Disabled or Enabled
Enables or disables the fifth stage residual overvoltage element. P344 and P345 Only.				
VN>5 Input	3B	52	VN2	0 = Derived, 1 = VN1, 2 = VN2
VN>5 uses measured neutral voltage from the VN2 input.				
VN>5 Function	3B	54	DT	0 = Disabled, 1 = DT, 2 = IDMT
Tripping characteristic setting of the fifth stage residual overvoltage element.				
VN>5 Voltage Set	3B	56	5*V1	1*V1 to 80*V1 step 1*V1
Pick-up setting for the fifth stage residual overvoltage characteristic.				
VN>5 Time Delay	3B	58	5 s	0 s to 100 s step 10 ms
Operating time delay setting for the fifth stage definite time residual overvoltage element.				
VN>5 TMS	3B	5A	1	0.5 to 100 step 0.5
Time multiplier setting to adjust the operating time of the IDMT characteristic. The characteristic is defined as above				
VN>5 tReset	3B	5C	0 s	0 s to 100 s step 10 ms
Reset/release definite time setting for the fifth stage characteristic.				
VN>6 Status	3B	60	Disabled	Disabled or Enabled
Enables or disables the sixth stage residual overvoltage element. P344 and P345 Only.				
VN>6 Input	3B	62	VN2	0 = Derived, 1 = VN1, 2 = VN2
VN>6 uses measured neutral voltage from the VN2 input.				
VN>6 Function	3B	64	DT	0 = Disabled, 1 = DT, 2 = IDMT
Tripping characteristic setting of the sixth stage residual overvoltage element.				
VN>6 Voltage Set	3B	66	5*V1	1*V1 to 80*V1 step 1*V1
Pick-up setting for the sixth stage residual overvoltage characteristic.				
VN>6 Time Delay	3B	68	10 s	0 s to 100 s step 10 ms
Operating time delay setting for the sixth stage definite time residual overvoltage element.				
VN>6 TMS	3B	6A	1	0.5 to 100 step 0.5
Time multiplier setting to adjust the operating time of the IDMT characteristic. The characteristic is defined as above				
VN>6 tReset	3B	6C	0 s	0 s to 100 s step 10 ms
Reset/release definite time setting for the sixth stage characteristic.				

Table 14 - Residual overvoltage protection settings

4.13 100% Stator Earth Fault (27TN/59TN/64S)

100% stator earth fault protection via third harmonic voltage measurement is available in the P343/P344/P345. A 3rd harmonic undervoltage protection element is included. This element is supervised by a 3-phase undervoltage element to prevent maloperation when running up/down the generator. Additional three phase active, reactive and apparent power supervision elements can also be enabled for this element. A third harmonic neutral over voltage protection is also provided. Each element has a definite time delay setting.

The 100% stator earth fault protection via low frequency injection is only available in the P345. It includes 2 stages of under resistance protection and an overcurrent protection stage. The under resistance protection is designed as a two stage protection system, one alarm stage (64S R<1 Alarm) and one trip stage (64S R<2 Trip), with each stage having a definite time delay setting. The overcurrent stage (64S I> Trip) is a single protection stage with a definite time delay setting. The protection includes a supervision element to evaluate a failure of the low frequency generator or the low frequency connection. The operation of an undervoltage and an undercurrent element after a time delay are used to indicate a failure. In case of a failure the protection is blocked and an alarm given.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 100% STATOR EF	3C	00		
GROUP 1 100% STATOR EF				
VN 3rd Harmonic	3C	01	VN3H< Enabled	0 = Disabled, 1 = VN3H< Enabled, 2 = VN3H> Enabled
Operating mode of the 3rd harmonic 100% stator earth fault protection defining – disabled or 3rd harmonic undervoltage or 3rd harmonic overvoltage. (P343, P344, P345 only).				
100% St EF VN3H<	3C	02	1*V1	0.3*V1 to 20*V1 step 0.1*V1
Pick-up setting for the 3rd harmonic undervoltage protection element.				
VN3H< Delay	3C	03	5 s	0 s to 100 s step 10 ms
Operating time-delay setting of the 3rd harmonic undervoltage protection.				
V< Inhibit set	3C	04	80*V1	30*V1 to 120*V1 step 1*V1
Pick-up setting for undervoltage inhibit of the 3rd harmonic 100% stator earth fault protection.				
P< Inhibit	3C	05	Disabled	Disabled or Enabled
Enables or disables the power (W) inhibit of the 3rd harmonic 100% stator earth fault protection.				
P< Inhibit set	3C	06	4*V1*In	4*V1*In to 200*V1*In step 0.5*V1*In
Pick-up setting for the power (W) inhibit of the 3rd harmonic 100% stator earth fault protection.				
Q< Inhibit	3C	07	Disabled	Disabled or Enabled
Enables or disables the reactive power (VAr) inhibit of the 3rd harmonic 100% stator earth fault protection.				
Q< Inhibit set	3C	08	4*V1*In	4*V1*In to 200*V1*In step 0.5*V1*In
Pick-up setting for the reactive power (VAr) inhibit of the 3rd harmonic 100% stator earth fault protection.				
S< Inhibit	3C	09	Disabled	Disabled or Enabled
Enables or disables the apparent power (VA) inhibit of the 3rd harmonic 100% stator earth fault protection.				
S< Inhibit set	3C	0A	4*V1*In	4*V1*In to 200*V1*In step 0.5*V1*In
Pick-up setting for the apparent power (VA) inhibit of the 3rd harmonic 100% stator earth fault protection.				
100% St EF VN3H>	3C	0B	0.2*V1	0.3*V1 to 20*V1 step 0.1*V1
Pick-up setting for the 3rd harmonic overvoltage protection element.				
VN3H> Delay	3C	0C	1 s	0 s to 100 s step 10 ms
Operating time-delay setting of the 3rd harmonic overvoltage protection.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
64S LF Injection	3C	10	Enabled	Disabled or Enabled
Enables or disables the low frequency injection 100% stator earth fault protection (64S). Available to P345 only				
64S R Factor	3C	14	10	0.01 to 200 step 0.01
R factor setting, defines the primary to secondary ratio factor for the resistance, reactance and conductance, R Primary = R Secondary x R Factor.				
64S R<1 Alarm	3C	1C	Enabled	Disabled or Enabled
Enables or disables the 64S under resistance alarm element.				
64S R<1 Alm Set	3C	20	1000 Ω	100 Ω to 7000 Ω step 1 Ω
Pick-up setting for the 64S first stage under resistance element with 64S R Factor = 1.				
64S R<1 Alm Dly	3C	24	1 s	0 s to 100 s step 10 ms
Operating time-delay setting of the 64S first stage under resistance alarm element.				
64S R<2 Trip	3C	28	Enabled	Disabled or Enabled
Enables or disables the 64S under resistance trip element with 64S R Factor = 1.				
64S R<2 Trip Set	3C	2C	200 Ω	100 Ω to 7000 Ω step 1 Ω
Pick-up setting for the 64S second stage under resistance trip element.				
64S R<2 Trip Dly	3C	30	1 s	0 s to 100 s step 10 ms
Operating time-delay setting of the 64S second stage under resistance trip element.				
64S Angle Comp	3C	34	0 °	-60 ° to 60 ° step 0.1 °
64S Angle compensation setting.				
64S Series R	3C	38	0 Ω	0 Ω to 700 Ω step 0.1 Ω
64S series resistance setting with 64S R Factor = 1.				
64S Parallel G	3C	3C	0 S	0 S to 0.1 S step 0.0000001 S
64S parallel conductance setting with 64S R Factor = 1.				
64S Overcurrent	3C	40	Enabled	Disabled or Enabled
Enables or disables the 64S overcurrent trip element.				
64S I>1 Trip Set	3C	44	0.5 A	0.02 A to 1.5 A step 0.01 A
Pick-up setting for the 64S overcurrent trip element.				
64S I>1 Trip Dly	3C	48	1 s	0 s to 100 s step 10 ms
Operating time-delay setting of the 64S overcurrent trip element.				
64S Supervision	3C	4C	Disabled	Disabled or Enabled
Enables or disables the 64S supervision element.				
64S V< Set	3C	50	1 V	0.3 V to 25 V step 0.1 V
Pick-up setting for the 64S supervision undervoltage element.				
64S I< Set	3C	54	0.01 A	0.005 A to 0.04 A step 0.001 A
Pick-up setting for the 64S supervision undercurrent element.				
64S Superv'n Dly	3C	58	1 s	0 s to 100 s step 10 ms
Operating time-delay setting of the 64S supervision element.				

Table 15 - 100% stator earth protection settings

4.14 Overfluxing, V/Hz (24)

The relays provide a five-stage overfluxing element. The element measures the ratio of voltage (VAB), to frequency (V/Hz) and will operate when this ratio exceeds the setting. One stage can be set to operate with a DT or IDMT, this stage can be used to provide the protection trip output. There are also three other definite time stages which can be combined with the inverse time characteristic to create a combined multi-stage V/Hz trip operating characteristic using PSL. An inhibit signal is provided for the V/Hz>1 stage 1 only, which has the inverse time characteristic option. This allows a definite time stage to override a section of the inverse time characteristic if required. The inhibit has the effect of resetting the timer, the start signal and the trip signal.

There is also one definite time alarm stage.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 VOLTS/HZ	3D	00		
GROUP 1 VOLTS/HZ				
V/Hz Alm Status	3D	01	Enabled	Disabled or Enabled
Enable or disables the V/Hz alarm element.				
V/Hz Alarm Set	3D	02	2.31*V1/Hz	1.5*V1/Hz to 3.5*V1/Hz step 0.01*V1/Hz
Pick-up setting for the V/Hz alarm element.				
V/Hz Alarm Delay	3D	03	10 s	0 s to 100 s step 10 ms
Operating time-delay setting of the V/Hz alarm element.				
V/Hz>1 Status	3D	10	Enabled	Disabled or Enabled
Enables or disables the V/Hz first stage trip element.				
V/Hz>1 Trip Func	3D	13	DT	0 = DT, 1 = IDMT
Tripping characteristic setting of the V/Hz first stage trip element.				
V/Hz>1 Trip Set	3D	16	2.42*V1/Hz	1.5*V1/Hz to 3.5*V1/Hz step 0.01*V1/Hz
Pick-up setting for the V/Hz first stage trip element.				
V/Hz>1 Trip TMS	3D	19	1	0.01 to 12 step 0.01
Setting for the time multiplier setting to adjust the operating time of the IDMT characteristic. The characteristic is defined as follows: t = TMS / (M - 1)2 Where: M = (V/f) / (V/f Trip Setting) V = Measured voltage F = Measured frequency				
V/Hz>1 Delay	3D	1A	60 s	0 s to 600 s step 10 ms
Operating time-delay setting of the V/Hz first stage trip element.				
V/Hz>2 Status	3D	20	Enabled	Disabled or Enabled
Enables or disables the V/Hz second stage trip element.				
V/Hz>2 Trip Set	3D	25	2.64*V1/Hz	1.5*V1/Hz to 3.5*V1/Hz step 0.01*V1/Hz
Pick-up setting for the V/Hz second stage trip element.				
V/Hz>2 Delay	3D	2A	3 s	0 s to 600 s step 10 ms
Operating time-delay setting of the V/Hz second stage trip element.				
V/Hz>3 Status	3D	30	Enabled	Disabled or Enabled
Enables or disables the V/Hz third stage trip element.				
V/Hz>3 Trip Set	3D	35	2.86*V1/Hz	1.5*V1/Hz to 3.5*V1/Hz step 0.01*V1/Hz
Pick-up setting for the V/Hz third stage trip element.				
V/Hz>3 Delay	3D	3A	2 s	0 s to 600 s step 10 ms

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Operating time-delay setting of the V/Hz third stage trip element.				
V/Hz>4 Status	3D	40	Enabled	Disabled or Enabled
Enables or disables the V/Hz fourth stage trip element.				
V/Hz>4 Trip Set	3D	45	3.08*V1/Hz	1.5*V1/Hz to 3.5*V1/Hz step 0.01*V1/Hz
Pick-up setting for the V/Hz fourth stage trip element.				
V/Hz>4 Delay	3D	4A	1 s	0 s to 600 s step 10 ms
Operating time-delay setting of the V/Hz fourth stage trip element.				

Table 16 - Overfluxing protection settings

4.15 Rate of Change of Frequency Protection

The relay provides four independent stages of rate of change of frequency protection (df/dt+t). Depending upon whether the rate of change of frequency setting is set positive, negative or both, the element will react to rising, falling or both rising and falling frequency conditions respectively, with an incorrect setting being indicated if the threshold is set to zero.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 DF/DT	3E	00		
GROUP 1 DF/DT				
Operating Mode	3E	10	Rolling Window	Fixed Window/Rolling Window
Selects the algorithm method, Fixed or Rolling Window, used for df/dt calculation.				
df/dt Avg Cycles	3E	11	3	2 to 12 step 1
Sets the number of power system cycles that are used to average the rate of change of frequency measurement.				
df/dt Iterations	3E	12	2	1 to 4 step 1
Sets the number of iterations of the df/dt protection element to obtain a start signal. For example if Operating Mode is Fixed Window and df/dt Avg Cycles = 3 and df/dt Iterations =2 then df/dt start will be after 2 consecutive 3 cycle windows above setting.				
df/dt>1 Status	3E	20	Enabled	Disabled or Enabled
Setting to enable or disable the first stage df/dt element.				
df/dt>1 Setting	3E	21	0.2 Hz/s	100 mHz/s to 10 Hz/s step 10 mHz/s
Pick-up setting for the first stage df/dt element.				
df/dt>1 Dir'n	3E	22	Both	Negative, Positive or Both
This setting determines whether the element will react to rising or falling frequency conditions respectively, with an incorrect setting being indicated if the threshold is set to zero.				
df/dt>1 Time	3E	23	500 ms	0 s to 100 s step 10 ms
Operating time-delay setting for the first stage df/dt element.				
df/dt>1 f L/H	3E	24	Enabled	Disabled or Enabled
Enables or disables the low and high frequency block function for the first stage of df/dt protection. The df/dt>1 stage is blocked if the frequency is in the deadband defined by the df/dt>1 F Low and df/dt>1 F High setting. This is typically required for loss of grid applications.				
df/dt>1 f Low	3E	25	49.5 Hz	45 Hz to 65 Hz step 0.01 Hz
Setting for the df/dt>1 low frequency blocking.				
df/dt>1 f High	3E	26	50.5 Hz	45 Hz to 65 Hz step 0.01 Hz
Setting for the df/dt>1 high frequency blocking.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
df/dt>2 Status	3E	30	Enabled	Disabled or Enabled
Setting to enable or disable the second stage df/dt element.				
df/dt>2 Setting	3E	31	0.2 Hz/s	100 mHz/s to 10 Hz/s step 10 mHz/s
Pick-up setting for the second stage df/dt element.				
df/dt>2 Dir'n	3E	32	Positive	Negative, Positive or Both
This setting determines whether the element will react to rising or falling frequency conditions respectively.				
df/dt>2 Time	3E	33	500 ms	0 s to 100 s step 10 ms
Operating time-delay setting for the second stage df/dt element.				
df/dt>3 Status	3E	40	Enabled	Disabled or Enabled
Setting to enable or disable the third stage df/dt element.				
df/dt>3 Setting	3E	41	0.2 Hz/s	0.1 Hz/s to 10 Hz/s step 0.01 Hz/s
Pick-up setting for the third stage df/dt element.				
df/dt>3 Dir'n	3E	42	Positive	Negative, Positive or Both
This setting determines whether the element will react to rising or falling frequency conditions respectively.				
df/dt>3 Time	3E	43	500 ms	0 s to 100 s step 10 ms
Operating time-delay setting for the third stage df/dt element.				
df/dt>4 Status	3E	50	Enabled	Disabled or Enabled
Setting to enable or disable the fourth stage df/dt element.				
df/dt>4 Setting	3E	51	0.2 Hz/s	0.1 Hz/s to 10 Hz/s step 0.01 Hz/s
Pick-up setting for the fourth stage df/dt element.				
df/dt>4 Dir'n	3E	52	Positive	Negative, Positive or Both
This setting determines whether the element will react to rising or falling frequency conditions respectively.				
df/dt>4 Time	3E	53	500 ms	0 s to 100 s step 10 ms
Operating time-delay setting for the fourth stage df/dt element.				

Table 17 - df/dt protection settings

4.16 Dead Machine / Unintentional Energization at Standstill (50/27)

This function applies only to these relay products: P343/P344/P345

The relays provides dead machine protection. The dead machine protection consists on an undervoltage element which ensures the protection is enabled when the machine is not running or dead and an overcurrent element to detect when the generator CB has been unintentionally closed. The protection has a definite time delay to prevent operation during system faults and a delay on drop off timer to ensure that the protection remains operated following accidental closure of the CB when the undervoltage element could reset.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 DEAD MACHINE	40	00		
GROUP 1 DEAD MACHINE				
Dead Mach Status	40	01	Enabled	Disabled or Enabled
This setting is used to select the 3-phase current inputs used by the Dead Machine protection in the P343/P344/P345 - IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 CT inputs.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DM CT Source	40	02	IA-1 IB-1 IC-1	IA-1 IB-1 IC-1 or IA-2 IB-2 IC-2
Enables or disables the dead machine element.				
Dead Mach I>	40	03	0.1*In	0.08*In to 4*In step 0.01*In
Pick-up setting for the dead machine overcurrent element.				
Dead Mach V<	40	04	80*V1	10*V1 to 120*V1 step 1*V1
Pick-up setting for the dead machine undervoltage element.				
Dead Mach tPU	40	05	5 s	0 s to 10 s step 0.1 s
Operation time delay setting for the under voltage element of the dead machine function.				
Dead Mach tDO	40	06	500 ms	0 s to 10 s step 0.1 s
Drop-off time delay setting for the under voltage element of the dead machine function.				

Table 18 - Dead machine protection settings

4.17 Voltage Protection (27/59/47)

The undervoltage and overvoltage protection included within the relay consists of two independent stages. Two stages are included to provide both alarm and trip stages, where required. These are configurable as either phase to phase or phase to neutral measuring. The undervoltage stages may be optionally blocked by a pole dead (CB Open) condition.

The first stage of under/overvoltage protection has a time-delayed characteristics which is selectable between IDMT, or DT. The second stage is definite time only.

Negative phase sequence overvoltage protection is also included with a definite time delay.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 VOLT PROTECTION	42	00		
GROUP 1 VOLT PROTECTION				
UNDER VOLTAGE	42	01		
V< Measur't Mode	42	02	Phase-Neutral	0 = Phase-Phase, 1 = Phase-Neutral
Sets the measured input voltage, phase-phase or phase-neutral that will be used for the undervoltage elements.				
V< Operate Mode	42	03	Any Phase	0 = Any Phase, 1 = Three Phase
Setting that determines whether any phase or all three phases has to satisfy the undervoltage criteria before a decision is made.				
V<1 Function	42	04	DT	0 = Disabled, 1 = DT, 2 = IDMT
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	42	05	50*V1	10*V1 to 120*V1 step 1*V1
Pick-up setting for first stage undervoltage element.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
V<1 Time Delay	42	06	10 s	0 s to 100 s step 10 ms
Operating time-delay setting for the first stage definite time undervoltage element.				
V<1 TMS	42	07	1	0.05 to 100 step 0.05
Time multiplier setting to adjust the operating time of the IDMT characteristic.				
V<1 Poledead Inh	42	08	Enabled	Disabled or Enabled
If the setting 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	42	09	Disabled	Disabled or Enabled
Enables or disables the second stage undervoltage element.				
V<2 Voltage Set	42	0A	38*V1	10*V1 to 120*V1 step 1*V1
Pick-up setting for second stage undervoltage element.				
V<2 Time Delay	42	0B	5 s	0 s to 100 s step 10 ms
Operating time-delay setting for the second stage definite time undervoltage element.				
V<2 Poledead Inh	42	0C	Enabled	Disabled or Enabled
If the setting 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	42	0D		
V> Measur't Mode	42	0E	Phase-Phase	0 = Phase-Phase, 1 = Phase-Neutral
Sets the measured input voltage, phase-phase or phase-neutral that will be used for the overvoltage elements.				
V> Operate Mode	42	0F	Any Phase	0 = Any Phase,1 = Three Phase
Setting that determines whether any phase or all three phases has to satisfy the overvoltage criteria before a decision is made.				
V>1 Function	42	10	DT	0 = Disabled, 1 = DT, 2 = IDMT
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)				
V>1 Voltage Set	42	11	130*V1	60*V1 to 185*V1 step 1*V1
Pick-up setting for first stage overvoltage element.				
V>1 Time Delay	42	12	10	0 s to 100 s step 10 ms
Operating time-delay setting for the first stage definite time overvoltage element.				
V>1 TMS	42	13	1	0.05 to 100 step 0.05
Time multiplier setting to adjust the operating time of the IDMT characteristic.				
V>2 Status	42	14	Disabled	Disabled or Enabled
Enables or disables the second stage overvoltage element.				
V>2 Voltage Set	42	15	150*V1	60*V1 to 185*V1 step 1*V1
Pick-up setting for the second stage overvoltage element.				
V>2 Time Delay	42	16	500 ms	0 s to 100 s step 10 ms
Operating time-delay setting for the second stage definite time overvoltage element.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
NPS OVERVOLTAGE	42	20		
V2>1 Status	42	22	Disabled	Disabled or Enabled
Enables or disables the definite time negative sequence overvoltage element.				
V2>1 Voltage Set	42	26	15*V1	1*V1 to 150*V1 step 1*V1
Pick-up setting for the negative sequence overvoltage element.				
V2>1 Time Delay	42	28	1 s	0 s to 100 s step 10 ms
Operating time delay setting for the definite time negative sequence overvoltage element.				

Table 19 - Under/Overvoltage protection settings

4.18 Frequency Protection (81U/81O/81AB)

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.

The relays also include six bands of generator turbine abnormal frequency protection. Each band has its own frequency limit settings and an individual accumulative time measurement. Operation within each of these bands is monitored and the time added to a cumulative timer. An individual dead band time delay setting is provided for each band. Within this dead band time delay, the frequency is allowed to stay inside the band without initiating the accumulative time measurement. This delay allows the blade's resonance during under frequency conditions to be established first, thus avoiding unnecessary accumulation of time. The delay therefore does not contribute to the accumulated time.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 FREQ PROTECTION	43	00		
GROUP 1 FREQ PROTECTION				
UNDER FREQUENCY	43	01		
F<1 Status	43	02	Enabled	Disabled or Enabled
Enables or disables the first stage underfrequency element.				
F<1 Setting	43	03	49.5 Hz	45 Hz to 65 Hz step 0.01 Hz
Pick-up setting for the first stage underfrequency element.				
F<1 Time Delay	43	04	4 s	0 s to 100 s step 10 ms
Operating time-delay setting for the definite time first stage underfrequency element.				
F<2 Status	43	05	Disabled	Disabled or Enabled
Enables or disables the second stage underfrequency element.				
F<2 Setting	43	06	49 Hz	45 Hz to 65 Hz step 0.01 Hz
Pick-up setting for the second stage underfrequency element.				
F<2 Time Delay	43	07	3 s	0 s to 100 s step 10 ms
Operating time-delay setting for the definite time second stage underfrequency element.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
F<3 Status	43	08	Disabled	Disabled or Enabled
Enables or disables the third stage underfrequency element.				
F<3 Setting	43	09	48.5 Hz	45 Hz to 65 Hz step 0.01 Hz
Pick-up setting for the third stage underfrequency element.				
F<3 Time Delay	43	0A	2 s	0 s to 100 s step 10 ms
Operating time-delay setting for the definite time third stage underfrequency element.				
F<4 Status	43	0B	Disabled	Disabled or Enabled
Enables or disables the fourth stage underfrequency element.				
F<4 Setting	43	0C	48 Hz	45 Hz to 65 Hz step 0.01 Hz
Pick-up setting for the fourth stage underfrequency element.				
F<4 Time Delay	43	0D	1 s	0 s to 100 s step 10 ms
Operating time-delay setting for the definite time fourth stage underfrequency element.				
F< Function Link	43	0E	0000(bin)	Bit 00 = F<1 Poledead Blk, Bit 01 = F<2 Poledead Blk, Bit 02 = F<3 Poledead Blk, Bit 03 = F<4 Poledead Blk
Settings that determine whether pole dead logic signals blocks the underfrequency elements. With the relevant bit set to 1, the relevant underfrequency 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 underfrequency protection to reset when the circuit breaker opens to cater for line or bus side VT applications.				
OVER FREQUENCY	43	0F		
F>1 Status	43	10	Enabled	Disabled or Enabled
Enables or disables the first stage overfrequency element.				
F>1 Setting	43	11	50.5 Hz	45 Hz to 68 Hz step 0.01 Hz
Pick-up setting for the first stage overfrequency element.				
F>1 Time Delay	43	12	2 s	0 s to 100 s step 10 ms
Operating time-delay setting for the first stage overfrequency element.				
F>2 Status	43	13	Disabled	Disabled or Enabled
Enables or disables the second stage overfrequency element.				
F>2 Setting	43	14	51 Hz	45 Hz to 68 Hz step 0.01 Hz
Pick-up setting for the second stage overfrequency element.				
F>2 Time Delay	43	15	1 s	0 s to 100 s step 10 ms
Operating time-delay setting for the second stage overfrequency element.				
TURBINE F PROT	43	20		
Turbine Abnormal Frequency Protection				
Turbine F Status	43	22	Disabled	Disabled or Enabled
Enables or disables the turbine abnormal frequency element.				
Band 1 Status	43	24	Enabled	Disabled or Enabled
Enables or disables the turbine abnormal frequency Band 1 element.				
Band 1 Freq Low	43	26	46.5 Hz	20 Hz to 70 Hz step 0.01 Hz
Lower limit frequency setting for the Band 1 element.				
Band 1 Freq High	43	28	47 Hz	20 Hz to 70 Hz step 0.01 Hz
Upper limit frequency setting for the Band 1 element.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Band 1 Duration	43	2A	1 s	0 s to 3600000 s step 10 ms
Band 1 Accumulated Time Threshold. Accumulation time-delay setting for frequency in the Band 1 element.				
Band 1 Dead Time	43	2C	200 ms	0 s to 200 s step 10 ms
Time-delay setting before time accumulation starts for the Band 1 element.				
Band 2 Status	43	34	Enabled	Disabled or Enabled
Enables or disables the turbine abnormal frequency Band 2 element.				
Band 2 Freq Low	43	36	47 Hz	20 Hz to 70 Hz step 0.01 Hz
Lower limit frequency setting for the Band 2 element.				
Band 2 Freq High	43	38	47.5 Hz	20 Hz to 70 Hz step 0.01 Hz
Upper limit frequency setting for the Band 2 element.				
Band 2 Duration	43	3A	2.5 s	0 s to 3600000 s step 10 ms
Band 2 Accumulated Time Threshold. Accumulation time-delay setting for frequency in the Band 2 element.				
Band 2 Dead Time	43	3C	200 ms	0 s to 200 s step 10 ms
Time-delay setting before time accumulation starts for the Band 2 element.				
Band 3 Status	43	44	Enabled	Disabled or Enabled
Enables or disables the turbine abnormal frequency Band 3 element.				
Band 3 Freq Low	43	46	47.5 Hz	20 Hz to 70 Hz step 0.01 Hz
Lower limit frequency setting for the Band 3 element.				
Band 3 Freq High	43	48	48 Hz	20 Hz to 70 Hz step 0.01 Hz
Upper limit frequency setting for the Band 3 element.				
Band 3 Duration	43	4A	14 s	0 s to 3600000 s step 10 ms
Band 3 Accumulated Time Threshold. Accumulation time-delay setting for frequency in the Band 3 element.				
Band 3 Dead Time	43	4C	200 ms	0 s to 200 s step 10 ms
Time-delay setting before time accumulation starts for the Band 3 element.				
Band 4 Status	43	54	Enabled	Disabled or Enabled
Enables or disables the turbine abnormal frequency Band 4 element.				
Band 4 Freq Low	43	56	48 Hz	20 Hz to 70 Hz step 0.01 Hz
Lower limit frequency setting for the Band 4 element.				
Band 4 Freq High	43	58	48.5 Hz	20 Hz to 70 Hz step 0.01 Hz
Upper limit frequency setting for the Band 4 element.				
Band 4 Duration	43	5A	100 s	0 s to 3600000 s step 10 ms
Band 4 Accumulated Time Threshold. Accumulation time-delay setting for frequency in the Band 4 element.				
Band 4 Dead Time	43	5C	200 ms	0 s to 200 s step 10 ms
Time-delay setting before time accumulation starts for the Band 4 element.				
Band 5 Status	43	64	Enabled	Disabled or Enabled
Enables or disables the turbine abnormal frequency Band 5 element.				
Band 5 Freq Low	43	66	48.5 Hz	20 Hz to 70 Hz step 0.01 Hz
Lower limit frequency setting for the Band 5 element.				
Band 5 Freq High	43	68	49 Hz	20 Hz to 70 Hz step 0.01 Hz
Upper limit frequency setting for the Band 5 element.				
Band 5 Duration	43	6A	540 s	0 s to 3600000 s step 10 ms
Band 5 Accumulated Time Threshold. Accumulation time-delay setting for frequency in the Band 5 element.				
Band 5 Dead Time	43	6C	200 ms	0 s to 200 s step 10 ms

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Time-delay setting before time accumulation starts for the Band 5 element.				
Band 6 Status	43	74	Enabled	Disabled or Enabled
Enables or disables the turbine abnormal frequency Band 6 element.				
Band 6 Freq Low	43	76	49 Hz	20 Hz to 70 Hz step 0.01 Hz
Lower limit frequency setting for the Band 6 element.				
Band 6 Freq High	43	78	49.5 Hz	20 Hz to 70 Hz step 0.01 Hz
Upper limit frequency setting for the Band 6 element.				
Band 6 Duration	43	7A	3000 s	0 s to 3600000 s step 10 ms
Band 6 Accumulated Time Threshold. Accumulation time-delay setting for frequency in the Band 6 element.				
Band 6 Dead Time	43	7C	200 ms	0 s to 200 s step 10 ms
Time-delay setting before time accumulation starts for the Band 6 element.				

Table 20 - Frequency protection settings

4.19 Resistor Temperature Device (RTD)

The relays can optionally provide temperature protection from 10 PT100 Resistor Temperature Devices (RTD). Each RTD has a definite time trip and alarm stage.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 RTD PROTECTION	44	00		
GROUP 1 RTD PROTECTION				
Select RTD	44	01	0000000000(bin)	Bit 00=RTD Input 1 to Bit 09=RTD Input 10
10 bit setting to enable or disable the 10 RTDs. For each bit 1 = Enabled, 0 = Disabled.				
RTD 1 Alarm Set	44	02	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 1 alarm element.				
RTD 1 Alarm Dly	44	03	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 1 alarm element.				
RTD 1 Trip Set	44	04	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 1 trip element.				
RTD 1 Trip Dly	44	05	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 1 trip element.				
RTD 2 Alarm Set	44	06	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 2 alarm element.				
RTD 2 Alarm Dly	44	07	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 2 alarm element.				
RTD 2 Trip Set	44	08	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 2 trip element.				
RTD 2 Trip Dly	44	09	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 2 trip element.				
RTD 3 Alarm Set	44	0A	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 3 alarm element.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
RTD 3 Alarm Dly	44	0B	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 3 alarm element.				
RTD 3 Trip Set	44	0C	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 3 trip element.				
RTD 3 Trip Dly	44	0D	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 3 trip element.				
RTD 4 Alarm Set	44	0E	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 4 alarm element.				
RTD 4 Alarm Dly	44	0F	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 4 alarm element.				
RTD 4 Trip Set	44	10	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 4 trip element.				
RTD 4 Trip Dly	44	11	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 4 trip element.				
RTD 5 Alarm Set	44	12	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 5 alarm element.				
RTD 5 Alarm Dly	44	13	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 5 alarm element.				
RTD 5 Trip Set	44	14	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 5 trip element.				
RTD 5 Trip Dly	44	15	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 5 trip element.				
RTD 6 Alarm Set	44	16	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 6 alarm element.				
RTD 6 Alarm Dly	44	17	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 6 alarm element.				
RTD 6 Trip Set	44	18	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 6 trip element.				
RTD 6 Trip Dly	44	19	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 6 trip element.				
RTD 7 Alarm Set	44	1A	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 7 alarm element.				
RTD 7 Alarm Dly	44	1B	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 7 alarm element.				
RTD 7 Trip Set	44	1C	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 7 trip element.				
RTD 7 Trip Dly	44	1D	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 7 trip element.				
RTD 8 Alarm Set	44	1E	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 8 alarm element.				
RTD 8 Alarm Dly	44	1F	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 8 alarm element.				
RTD 8 Trip Set	44	20	85 °C	0 °C to 200 °C step 1 °C

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Temperature setting for the RTD 8 trip element.				
RTD 8 Trip Dly	44	21	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 8 trip element.				
RTD 9 Alarm Set	44	22	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 9 alarm element.				
RTD 9 Alarm Dly	44	23	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 9 alarm element.				
RTD 9 Trip Set	44	24	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 9 trip element.				
RTD 9 Trip Dly	44	25	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 9 trip element.				
RTD 10 Alarm Set	44	26	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 10 alarm element.				
RTD 10 Alarm Dly	44	27	10 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 10 alarm element.				
RTD 10 Trip Set	44	28	85 °C	0 °C to 200 °C step 1 °C
Temperature setting for the RTD 10 trip element.				
RTD 10 Trip Dly	44	29	1 s	0 s to 100 s step 1 s
Operating time delay setting for the RTD 10 trip element.				

Table 21 - RTD protection settings

4.20 Circuit Breaker Fail and Undercurrent Function (50BF)

This function consists of a two-stage circuit breaker fail function that can be initiated by:

- Current based protection elements
- Non current based protection elements
- External protection elements

Current-based protection: the reset condition depends on undercurrent to determine whether the CB has opened.

Non current-based protection: the reset criteria can be selected from a setting to determine a CB Failure.

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. The current source of the undercurrent elements in the P343/P344/P345 can also be selected – terminal or neutral side CTs.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 CB FAIL & I<	45	00		
GROUP 1 CB FAIL & I<				
BREAKER FAIL	45	01		
CB Fail 1 Status	45	02	Enabled	Disabled or Enabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Enables or disables the first stage circuit breaker failure function.				
CB Fail 1 Timer	45	03	0.2 s	0 s to 10 s step 10 ms
Circuit breaker fail timer setting for stage 1 for which the initiating condition must be valid.				
CB Fail 2 Status	45	04	Disabled	Disabled or Enabled
Enables or disables the second stage circuit breaker failure function.				
CB Fail 2 Timer	45	05	400 ms	0 s to 10 s step 10 ms
Circuit breaker fail timer setting for stage 2 for which the initiating condition must be valid.				
CBF Non I Reset	45	06	CB Open & I<	0 = I< Only, 1 = CB Open & I<, 2 = Prot Reset & I<
Setting which determines the elements that will reset the circuit breaker fail time for non current based protection functions (e.g. voltage, frequency) initiating circuit breaker fail conditions.				
CBF Ext Reset	45	07	CB Open & I<	0 = I< Only, 1 = CB Open & I<, 2 = Prot Reset & I<
Setting which determines the elements that will reset the circuit breaker fail time for external protection functions initiating circuit breaker fail conditions.				
UNDER CURRENT	45	08		
I< Current Set	45	09	0.1*In	0.02*In to 3.2*In step 0.01*In
Circuit breaker fail phase fault undercurrent setting. This undercurrent element is used to reset the CB failure function initiated from the internal or external protection (Any Trip and Ext Trip 3Ph signals).				
IN< Current Set	45	0A	0.1*I2	0.02*I2 to 3.2*I2 step 0.01*I2
Circuit breaker fail earth fault undercurrent setting. This undercurrent element is used to reset the CB failure function initiated from the internal or external protection (Any Trip and Ext Trip 3Ph signals).				
ISEF< Current	45	0B	0.02*I3	0.001*I3 to 0.8*I3 step 0.0005*I3
Circuit breaker fail sensitive earth fault undercurrent setting. This undercurrent element is used to reset the CB failure function initiated from the sensitive earth fault protection.				
BLOCKED O/C	45	0C		
Remove I> Start	45	0D	Disabled	Disabled or Enabled
The ‘Remove I> Start’ setting if enabled sets DDB ‘I> BlockStart’ to OFF for a breaker fail condition. The ‘I> BlockStart’ DDB is the start signal from all stages of I> protection and is used in blocking schemes. When the block DDB is removed upstream protection is allowed to trip to clear the CB Fail fault condition.				
Remove IN> Start	45	0E	Disabled	Disabled or Enabled
The ‘Remove IN> Start’ setting if enabled sets DDB ‘IN/SEF>Blk Start’ to OFF for a breaker fail condition. The ‘IN/SEF>Blk Start’ DDB is the start signal from all stages of IN> and ISEF> protection and is used in blocking schemes. When the block DDB is removed upstream protection is allowed to trip to clear the CB Fail fault condition.				
I< CT Source	45	15	IA-1 IB-1 IC-1	0 = IA-1 IB-1 IC-1, 1 = IA-2 IB-2 IC-2
This setting is used to select the 3-phase current inputs used by the CB failure undercurrent elements in the P343/P344/P345 - neutral or terminal side CT inputs.				

Table 22 - CB Fail protection settings

4.21 Supervision (VTS, CTS and through Fault Monitoring)

The VTS feature in the relay operates when it detects a Negative Phase Sequence (NPS) voltage when there is no NPS 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 the NPS current. The use of negative sequence quantities ensures correct operation even where three-limb or V-connected VTs are used.

If all 3-phase voltages to the relay are lost, there are no NPS quantities to operate the VTS function, and the 3-phase voltages collapse. If this is detected without a corresponding change in any of the phase current signals (which would indicate a fault), a VTS condition is raised. In practice, the relay detects superimposed current signals, which are changes in the current applied to the relay.

If a VT is inadvertently left isolated before line energization, voltage-dependent elements may operate incorrectly. The previous VTS element detected 3-phase VT failure due to the absence of all three phase voltages with no corresponding change in current. However, on line energization there is a change in current, for example, due to load or line charging current. An alternative method of detecting 3-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 two conditions. The first is a 3-phase VT failure and the second is a close-up 3-phase fault. The first condition would require blocking of the voltage dependent function and the second would require tripping. To differentiate between these two conditions an overcurrent level detector (VTS I> Inhibit) is used to 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 3-phase fault. If the line is closed where a 3-phase VT failure is present, the overcurrent detector does not operate and a VTS block is applied. Closing onto a 3-phase fault results in operation of the overcurrent detector and prevents a VTS block from 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.

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 CT supervision can be set to operate from the residual voltage measured at the VNEUTRAL input (VN1 input) or the residual voltage derived from the three phase-neutral voltage inputs as selected by the ‘CTS Vn Input’ setting.

There are two stages of CT supervision CTS-1 and CTS-2. CTS-1 supervises the CT inputs to IA, IB, IC which are used by the biased differential protection and all the power, impedance and overcurrent based protection functions. CTS-2 supervises the CT inputs to IA-2, IB-2, IC-2 which are used by the biased or high impedance differential or interturn protection in the P343/P344/P345. The CTS-2 independent enabled/disabled setting is to prevent CTS-2 from giving unnecessary alarms when the Generator Differential is disabled. For interturn faults, some utilities may isolate the faulted winding section and return the generator to service, therefore producing unbalanced phase currents. Under these circumstances the CTS-2 may also need to be disabled or de-sensitized to prevent a false alarm and a false block.

Through Fault monitoring is implemented in the relay. Through faults are a major cause of transformer damage and failure. Both the insulation and the mechanical effects of fault currents are considered. The through fault current monitoring function in the relay is configured in the default PSL to trigger a fault record when the I^2t alarm level is exceeded. The fault record gives the peak fault current level and an I^2t calculation based on the recorded time duration and maximum current is performed for each phase. On P343/P344/P345 the winding to be monitored can be selected.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 SUPERVISION	46	00		
GROUP 1 SUPERVISION				
VT SUPERVISION	46	01		
VTS Status	46	02	Blocking	Blocking, Indication, disabled
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	46	03	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 240 ms.				
VTS Time Delay	46	04	5 s	1 s to 10 s step 100 ms
Operating time-delay setting of the VTS element upon detection of a voltage supervision condition.				
VTS I> Inhibit	46	05	10*In	0.08*In to 32*In step 0.01*In
This overcurrent setting is used to inhibit the voltage transformer supervision in the event of a loss of all 3 phase voltages caused by a close up 3 phase fault occurring on the system following closure of the CB to energize the line.				
VTS I2> Inhibit	46	06	0.05*In	0.05*In to 0.5*In step 0.01*In
This NPS overcurrent setting is used to inhibit the voltage transformer supervision in the event of a fault occurring on the system with negative sequence current above this setting.				
CT SUPERVISION	46	07		
CTS1 Status	46	08	Disabled	Disabled or Enabled
Enables or disables the current transformer supervision 1 element.				
CTS1 VN Input	46	09	Derived	0 = Measured, 1 = Derived
Residual/neutral voltage source for CTS.				
CTS1 VN< Inhibit	46	0A	5*V1	0.5*V1 to 22*V1 step 0.5*V1
Residual/neutral voltage setting to inhibit the CTS1 element.				
CTS1 IN> Set	46	0B	0.2*In	0.08*In to 4*In step 0.01*In
Residual/neutral current setting for a valid current transformer supervision condition for CTS.				
CTS1 Time Delay	46	0C	5 s	0 s to 10 s step 1 s
Operating time-delay setting of CTS.				
CTS2 Status	46	20	Disabled	Disabled or Enabled
Enables or disables the current transformer supervision 2 element. (P343/P344/P345)				
CTS2 VN Input	46	24	Derived	0 = Measured, 1 = Derived
Residual/neutral voltage source for CTS2.				
CTS2 VN< Inhibit	46	28	5*V1	0.5*V1 to 22*V1 step 0.5*V1
Residual/neutral voltage setting to inhibit the CTS2 element.				
CTS2 IN> Set	46	2C	0.2*In	0.08*In to 4*In step 0.01*In
Residual/neutral current setting for a valid current transformer supervision condition for CTS2.				
CTS2 Time Delay	46	30	5 s	0 s to 10 s step 1 s
Operating time-delay setting of CTS2.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DIFF CTS Status	46	31	Enabled	Disabled or Enabled
Enables or disables the differential current transformer supervision function. (P343/P344/P345)				
Diff CTS Mode	46	32	Restrain	0 = Indication, 1= Restrain
In Indication mode, the CTS alarm is issued without delay when a CT failure is detected. The differential protection would remain unrestricted. Therefore, the risk of unwanted tripping under load current is present. In Restrain mode, the differential protection is set to the Is-CTS setting when a CT failure is detected. This setting increases the restrain region of the differential characteristic. The CTS alarm is issued after the time delay defined in CTS time relay.				
CTS Time Delay	46	33	2 s	0 s to 10 s step 100ms
Differential CTS alarm time delay on detection of a current transformer supervision condition. This setting does not affect the CTS blocking operation.				
CTS I1	46	34	0.1	0% to 100% step 1%
Set release threshold.				
CTS I2/I1>1	46	35	0.05	5% to 100% step 1%
Low set ratio of negative to positive sequence current.				
CTS I2/I1>2	46	36	0.3	5% to 100% step 1%
High set ratio of negative to positive sequence current.				
THROUGH FAULT	46	50		
Through Fault	46	51	Enabled	Disabled or Enabled
Enables or disables monitoring of through faults.				
Monitored Input	46	52	HV	0= HV, 1= LV
Selects the input winding to be monitored. (P343/P344/P345)				
TF I> Trigger	46	53	1*In	0.08*In to 16*In step 0.01*In
A through fault event is recorded if any of the phase currents is larger than this setting.				
TF I2t> Alarm	46	54	800*In*In s	0 to 50000*In*In s step 1*In*In s
An alarm is asserted if the maximum cumulative I2t in the three phases exceeds this setting.				

Table 23 - VTS, CTS and through fault monitoring protection settings

4.22 Sensitive Power Protection (32R/32O/32l)

The single phase power protection included in the relay provides two stages of sensitive power protection. Each stage can be independently selected as either reverse power, over power, low forward power or disabled. The direction of operation of the power protection, forward or reverse can also be defined with the operating mode setting.

Note *The high impedance REF element of the relay shares the same sensitive current input as the SEF protection and sensitive power protection. Hence, only one of these elements may be selected.*

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 SENSITIVE POWER	47	00		
GROUP 1 SENSITIVE POWER				
Comp Angle	47	20	0 °	-5 ° to 5 ° step 0.1 °
Compensation Angle to correct for CT/VT errors				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Volt Ph Select	47	22	VAN	0 = VAN, 1 = VBN, 2 = VCN
Allows the selection of the VT phase to use for Sensitive Power protection				
Operating Mode	47	24	Generating	0 = Generating, 1 = Motoring
Operating mode of the sensitive power protection defining forward/reverse direction – Generating = forward power towards the busbar, Motoring = forward power towards the machine. Assumes CT connections as per standard connection diagrams.				
Sen Power1 Func	47	28	Reverse	0 = Disabled, 2 = Reverse, 3 = Low Forward, 4 = Over
First stage sensitive power function operating mode.				
Sen -P>1 Setting	47	2C	0.5*V1*I3	0.3*V1*I3 to 100*V1*I3 step 0.1*V1*I3
Pick-up setting for the first stage reverse sensitive power protection element.				
Sen P<1 Setting	47	30	0.5*V1*I3	0.3*V1*I3 to 100*V1*I3 step 0.1*V1*I3
Pick-up setting for the first stage low forward sensitive power protection element.				
Sen P>1 Setting	47	34	50*V1*I3	0.3*V1*I3 to 100*V1*I3 step 0.1*V1*I3
Pick-up setting for the first stage sensitive overpower protection element.				
Sen Power1 Delay	47	38	5 s	0 s to 100 s step 10 ms
Operating time-delay setting of the first stage sensitive power protection.				
Power1 DO Timer	47	3C	0 s	0 s to 100 s step 10 ms
Drop-off time delay setting of the first stage sensitive power protection function. Setting of the drop-off timer to a value other than zero, delays the resetting of the protection element timers for this period. By using the drop-off timer the relay will integrate the fault power pulses, thereby reducing fault clearance times.				
P1 PoleDead Inh	47	40	Enabled	Disabled or Enabled
If the setting 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 power protection to reset when the circuit breaker opens to cater for line or bus side VT applications.				
Sen Power2 Func	47	44	Low Forward	0 = Disabled, 2 = Reverse, 3 = Low Forward, 4 = Over
Second stage sensitive power function operating mode.				
Sen -P>2 Setting	47	48	0.5*V1*I3	0.3*V1*I3 to 100*V1*I3 step 0.1*V1*I3
Pick-up setting for the second stage reverse sensitive power protection element.				
Sen P<2 Setting	47	4C	0.5*V1*I3	0.3*V1*I3 to 100*V1*I3 step 0.1*V1*I3
Pick-up setting for the second stage low forward sensitive power protection element.				
Sen P>2 Setting	47	50	50*V1*I3	0.3*V1*I3 to 100*V1*I3 step 0.1*V1*I3
Pick-up setting for the second stage overpower protection element.				
Sen Power2 Delay	47	54	2 s	0 s to 100 s step 10 ms
Operating time-delay setting of the second stage sensitive power protection.				
Power2 DO Timer	47	58	0 s	0 s to 100 s step 10 ms
Drop-off time delay setting of the second stage sensitive power protection function. Setting of the drop-off timer to a value other than zero, delays the resetting of the protection element timers for this period. By using the drop-off timer the relay will integrate the fault power pulses, thereby reducing fault clearance times.				
P2 PoleDead Inh	47	5C	Enabled	Disabled, Enabled
If the setting 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 sensitive power protection to reset when the circuit breaker opens to cater for line or bus side VT applications.				

Table 24 - Sensitive power protection settings

4.23 Pole Slipping (78)

The P343/P344/P345 pole slipping characteristic consists of three parts. The first part is the lenticular (lens) characteristic. The second is a straight line referred to as the blinder that bisects the lens and divides the impedance plane into the left and right halves. The third is a reactance line which is perpendicular to the blinder.
The inclination of the lens and the blinder, (Blinder Angle) is determined by the angle of the total system impedance. The equivalent impedance of the system and the step-up transformer determines the forward reach of the lens, (PSlip Za Forward), whereas the generator's transient reactance determines the reverse reach (PSlip Zb Reverse). The width of the lens is varied by the setting of the lens angle (Lens Angle). A reactance line (PSlip Zc), perpendicular to the axis of the lens, is used to distinguish whether the impedance centre of the swing is located in the power system or in the generator. The reactance line splits the lens into Zone 1 (lens below the line) and Zone 2 (all of the lens). During a pole slip the impedance crosses the lens spending at least time PSlip T1 and PSlip T2 in each half. Counters are available for both zone 1 and zone 2 to count the number of pole slip cycles before a trip. There is a reset timer (PSlip Reset Time) which is required to reset the counters for pole slips that are cleared by external protection.

When a generator is out of step with the system, the impedance locus is expected to traverse from right to left across the lens and the blinder. However, if the generator is running as a motor, as in the pumping mode of a pump storage generator, the impedance locus is expected to swing from the left to the right. A pole slip mode setting is provided to determine whether the protection operates in a 'Generating' mode or in a 'Motoring' mode or 'Both'. For a pump storage generator, its operation can switch from generating mode to motoring mode and vice versa.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 POLE SLIPPING	49	00		
GROUP 1 POLE SLIPPING				
PSlip Function	49	01	Enabled	Disabled or Enabled
Enables or disables the pole slipping protection.				
Z Based PoleSlip	49	02		
Pole Slip Mode	49	03	Generating	0 = Generating, 1 = Motoring, 2 = Both
Selection of the pole slip operating mode.				
PSlip Za Forward	49	04	100*V1/In	0.5*V1/In to 350*V1/In step 0.5*V1/In
Forward impedance reach setting of the pole slipping lens characteristic.				
PSlip Zb Reverse	49	05	150*V1/In	0.5*V1/In to 350*V1/In step 0.5*V1/In
Reverse impedance reach setting of the pole slipping lens characteristic.				
Lens Angle	49	06	120 °	90 ° to 150 ° step 1 °
Lens angle setting. The lens width is proportional to the lens angle, a 90deg lens angle is a circle.				
PSlip Timer T1	49	07	15 ms	0 s to 1 s step 5 ms
Minimum time-delay setting that impedance must remain in half of the lens characteristic. The lens is split in half by the blinder defining left and right hand halves. Timer T1 starts when the impedance is in the right hand half of the lens when the operating mode is Generating and the left hand half of the lens when the operating mode is Motoring. If the operating mode is set to Both then T1 starts timing in whichever half the impedance first appears.				
PSlip Timer T2	49	08	15 ms	0 s to 1 s step 5 ms
Minimum time-delay setting that impedance must remain in half of the lens characteristic. The lens is split in half by the blinder defining left and right hand halves. Timer T2 starts when the impedance is in the opposite half of the lens characteristic to T1 operating.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Blinder Angle	49	09	75 °	20 ° to 90 ° step 1 °
Blinder angle setting. This defines the inclination of the lens characteristic which should be consistent with the system impedance angle.				
PSlip Zc	49	0A	50*V1/In	0.5*V1/In to 350*V1/In step 0.5*V1/In
Forward impedance reach setting of the reactance line. The reactance line splits the lens into 2 zones. Zone 1 is the lens characteristic below the reactance line and Zone 2 is all of the lens characteristic. The reactance line provides a means of discriminating pole slipping within the generator or within the power system. Typically the reactance line is set to encompass the generator and part of the generator-transformer.				
Zone1 Slip Count	49	0B	1	1 to 20 step 1
Number of allowed pole slips in zone 1.				
Zone2 Slip Count	49	0C	2	1 to 20 step 1
Number of allowed pole slips in zone 2.				
PSlip Reset Time	49	0D	30 s	0 s to 100 s step 10 ms
Reset time setting for pole slip protection. Resets the counters for pole slips cleared by external protection.				

Table 25 - Pole slipping protection settings

4.24 Input Labels

The column **GROUP x INPUT LABELS** is used to individually label each opto input that is available in the relay. The text is restricted to 16 characters and is available if 'Input Labels' are set visible under CONFIGURATION column.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 INPUT LABELS	4A	00		
GROUP 1 INPUT LABELS				
Opto Input 1	4A	01	Input L1	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 2	4A	02	Input L2	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 3	4A	03	Input L3	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 4	4A	04	Input L4	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 5	4A	05	Input L5	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 6	4A	06	Input L6	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 7	4A	07	Input L7	Editable 16 character string

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 8	4A	08	Input L8	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 9	4A	09	Input L9	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 10	4A	0A	Input L10	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 11	4A	0B	Input L11	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 12	4A	0C	Input L12	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 13	4A	0D	Input L13	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 14	4A	0E	Input L14	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 15	4A	0F	Input L15	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 16	4A	10	Input L16	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 17	4A	11	Input L17	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 18	4A	12	Input L18	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 19	4A	13	Input L19	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 20	4A	14	Input L20	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 21	4A	15	Input L21	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 22	4A	16	Input L22	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 23	4A	17	Input L23	Editable 16 character string

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 24	4A	18	Input L24	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 25	4A	19	Input L25	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 26	4A	1A	Input L26	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 27	4A	1B	Input L27	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 28	4A	1C	Input L28	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 29	4A	1D	Input L29	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 30	4A	1E	Input L30	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 31	4A	1F	Input L31	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				
Opto Input 32	4A	20	Input L32	Editable 16 character string
Text label to describe each individual opto input. This text will be displayed in the programmable scheme logic and event record description of the opto input.				

Table 26 - Input labels settings

4.25 Output Labels

The column **GROUP x OUTPUT LABELS** is used to individually label each output relay that is available in the relay. The text is restricted to 16 characters and is available if 'Output Labels' are set visible under CONFIGURATION column.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 OUTPUT LABELS	4B	00		
GROUP 1 OUTPUT LABELS				
Relay 1	4B	01	Output R1	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 2	4B	02	Output R2	Editable 16 character string

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 3	4B	03	Output R3	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 4	4B	04	Output R4	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 5	4B	05	Output R5	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 6	4B	06	Output R6	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 7	4B	07	Output R7	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 8	4B	08	Output R8	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 9	4B	09	Output R9	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 10	4B	0A	Output R10	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 11	4B	0B	Output R11	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 12	4B	0C	Output R12	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 13	4B	0D	Output R13	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 14	4B	0E	Output R14	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 15	4B	0F	Output R15	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 16	4B	10	Output R16	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 17	4B	11	Output R17	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 18	4B	12	Output R18	Editable 16 character string

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 19	4B	13	Output R19	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 20	4B	14	Output R20	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 21	4B	15	Output R21	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 22	4B	16	Output R22	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 23	4B	17	Output R23	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 24	4B	18	Output R24	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 25	4B	19	Output R25	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 26	4B	1A	Output R26	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 27	4B	1B	Output R27	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 28	4B	1C	Output R28	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 29	4B	1D	Output R29	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 30	4B	1E	Output R30	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 31	4B	1F	Output R31	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				
Relay 32	4B	20	Output R32	Editable 16 character string
Text label to describe each individual relay output contact. This text will be displayed in the programmable scheme logic and event record description of the relay output contact.				

Table 27 - Output labels settings

4.26 RTD Labels

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 RTD LABELS	4C	00		
GROUP 1 RTD LABELS				
RTD 1	4C	01	RTD 1	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 2	4C	02	RTD 2	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 3	4C	03	RTD 3	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 4	4C	04	RTD 4	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 5	4C	05	RTD 5	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 6	4C	06	RTD 6	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 7	4C	07	RTD 7	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 8	4C	08	RTD 8	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 9	4C	09	RTD 9	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				
RTD 10	4C	0A	RTD 10	Editable 16 character string
Text label to describe each individual RTD. This text will be displayed in the Measurements 3 menu and fault records for the description of the RTDs.				

Table 28 - RTD labels settings

4.27 Current Loop Inputs and Outputs (CLIO) Protection

Four analog or current loop inputs are optionally provided for transducers with ranges of 0 to 1 mA, 0 to 10 mA, 0 to 20 mA or 4 to 20 mA. The analog inputs can be used for various transducers such as vibration monitors, tachometers, pressure and temperature transducers. Associated with each input there are two protection stages, one for alarm and one for trip. Each stage can be individually enabled or disabled, and each stage has a Definite Time delay setting. The Alarm and Trip stages can be set for operation when the input value falls below the Alarm/Trip threshold **Under** or when the input current is above the input value **Over**. The 4 to 20 mA input has an undercurrent alarm element which can be used to indicate a fault with the transducer or wiring.

There are four analog current outputs with ranges of 0 to 1 mA, 0 to 10 mA, 0 to 20 mA or 4 to 20 mA, which can reduce the need for separate transducers. These outputs can be fed to standard moving coil ammeters for analog measurements or to a SCADA system using an existing analog RTU.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 CLIO PROTECTION	4D	00		
GROUP 1 CLIO PROTECTION				
CLIO Input 1	4D	02	Enabled	Disabled, Enabled
Enables or disables the current loop (transducer) input 1 element.				
CLI1 Input Type	4D	04	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 1 input type.				
CLI1 Input Label	4D	06	CLIO Input 1	Editable 16 character string
Current loop 1 input description. The minimum and maximum settings define the range but they have no units. The user can use the label to enter the transducer function and unit of measurement, e.g. Power MW, which is used in the Measurements 3 menu to describe the CLI1 measurement.				
CLI1 Minimum	4D	08	0	-9999 to 9999 step 0.1
Current loop input 1 minimum setting. Defines the lower range of the physical or electrical quantity measured by the transducer.				
CLI1 Maximum	4D	0A	100	-9999 to 9999 step 0.1
Current loop input 1 maximum setting. Defines the upper range of the physical or electrical quantity measured by the transducer.				
CLI1 Alarm	4D	0C	Disabled	Disabled, Enabled
Enables or disables the current loop input 1 alarm element.				
CLI1 Alarm Fn	4D	0E	Over	0 = Under, 1 = Over
Operating mode of the current loop input 1 alarm element.				
CLI1 Alarm Set	4D	10	50	CLI1 Minimum to CLI1 Maximum step 0.1
Pick-up setting for the current loop input 1 alarm element.				
CLI1 Alarm Delay	4D	12	1 s	0 s to 100 s step 100 ms
Operating time-delay setting of current loop input 1 alarm element.				
CLI1 Trip	4D	14	Disabled	Disabled, Enabled
Enables or disables the current loop input 1 trip element.				
CLI1 Trip Fn	4D	16	Over	0 = Under, 1 = Over
Operating mode of the current loop input 1 trip element.				
CLI1 Trip Set	4D	18	60	CLI1 Minimum to CLI1 Maximum step 0.1
Pick-up setting for the current loop input 1 trip element.				
CLI1 Trip Delay	4D	1A	0 s	0 s to 100 s step 100 ms

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Operating time-delay setting of current loop input 1 trip element.				
CLI1 I< Alarm	4D	1C	Disabled	Disabled, Enabled
Enables or disables the current loop input 1 undercurrent element used to supervise the 4-20mA input only.				
CLI1 I< Alm Set	4D	1E	0.0035 A	From 0 A to 4mA step 0.1mA
Pick-up setting for the current loop input 1 undercurrent element. (4 - 20 mA input only).				
CLIO Input 2	4D	22	Enabled	Disabled, Enabled
Enables or disables the current loop (transducer) input 2 element.				
CLI2 Input Type	4D	24	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 2 input type.				
CLI2 Input Label	4D	26	CLIO Input 2	Editable 16 character string
Current loop 2 input description. The minimum and maximum settings define the range but they have no units. The user can use the label to enter the transducer function and unit of measurement, e.g. Power MW, which is used in the Measurements 3 menu to describe the CLI2 measurement.				
CLI2 Minimum	4D	28	0	-9999 to 9999 step 0.1
Current loop input 2 minimum setting. Defines the lower range of the physical or electrical quantity measured by the transducer.				
CLI2 Maximum	4D	2A	100	-9999 to 9999 step 0.1
Current loop input 2 maximum setting. Defines the upper range of the physical or electrical quantity measured by the transducer.				
CLI2 Alarm	4D	2C	Disabled	Disabled, Enabled
Enables or disables the current loop input 2 alarm element.				
CLI2 Alarm Fn	4D	2E	Over	0 = Under, 1 = Over
Operating mode of the current loop input 2 alarm element.				
CLI2 Alarm Set	4D	30	50	CLI2 Minimum to CLI2 Maximum step 0.1
Pick-up setting for the current loop input 2 alarm element.				
CLI2 Alarm Delay	4D	32	1 s	0 s to 100 s step 100 ms
Operating time-delay setting of current loop input 2 alarm element.				
CLI2 Trip	4D	34	Disabled	Disabled, Enabled
Enables or disables the current loop input 2 trip element.				
CLI2 Trip Fn	4D	36	Over	0 = Under, 1 = Over
Operating mode of the current loop input 2 trip element.				
CLI2 Trip Set	4D	38	60	CLI2 Minimum to CLI2 Maximum step 0.1
Pick-up setting for the current loop input 2 trip element.				
CLI2 Trip Delay	4D	3A	0 s	0 s to 100 s step 100 ms
Operating time-delay setting of current loop input 2 trip element.				
CLI2 I< Alarm	4D	3C	Disabled	Disabled, Enabled
Enables or disables the current loop input 2 undercurrent element used to supervise the 4-20mA input only.				
CLI2 I< Alm Set	4D	3E	0.0035 A	From 0 A to 4mA step 0.1mA
Pick-up setting for the current loop input 2 undercurrent element. (4 - 20 mA input only).				
CLIO Input 3	4D	42	Enabled	Disabled, Enabled
Enables or disables the current loop (transducer) input 3 element.				
CLI3 Input Type	4D	44	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 3 input type.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CLI3 Input Label	4D	46	CLIO Input 3	Editable 16 character string
Current loop 3 input description. The minimum and maximum settings define the range but they have no units. The user can use the label to enter the transducer function and unit of measurement, e.g. Power MW, which is used in the Measurements 3 menu to describe the CLI2 measurement.				
CLI3 Minimum	4D	48	0	-9999 to 9999 step 0.1
Current loop input 3 minimum setting. Defines the lower range of the physical or electrical quantity measured by the transducer.				
CLI3 Maximum	4D	4A	100	-9999 to 9999 step 0.1
Current loop input 3 maximum setting. Defines the upper range of the physical or electrical quantity measured by the transducer.				
CLI3 Alarm	4D	4C	Disabled	Disabled, Enabled
Enables or disables the current loop input 3 alarm element.				
CLI3 Alarm Fn	4D	4E	Over	0 = Under, 1 = Over
Operating mode of the current loop input 3 alarm element.				
CLI3 Alarm Set	4D	50	50	CLI3 Minimum to CLI3 Maximum step 0.1
Pick-up setting for the current loop input 3 alarm element.				
CLI3 Alarm Delay	4D	52	1 s	0 s to 100 s step 100 ms
Operating time-delay setting of current loop input 3 alarm element.				
CLI3 Trip	4D	54	Disabled	Disabled, Enabled
Enables or disables the current loop input 3 trip element.				
CLI3 Trip Fn	4D	56	Over	0 = Under, 1 = Over
Operating mode of the current loop input 3 trip element.				
CLI3 Trip Set	4D	58	60	CLI3 Minimum to CLI3 Maximum step 0.1
Pick-up setting for the current loop input 3 trip element.				
CLI3 Trip Delay	4D	5A	0 s	0 s to 100 s step 100 ms
Operating time-delay setting of current loop input 3 trip element.				
CLI3 I< Alarm	4D	5C	Disabled	Disabled, Enabled
Enables or disables the current loop input 3 undercurrent element used to supervise the 4-20mA input only.				
CLI3 I< Alm Set	4D	5E	0.0035 A	From 0 A to 4mA step 0.1mA
Pick-up setting for the current loop input 3 undercurrent element. (4 - 20 mA input only).				
CLIO Input 4	4D	62	Enabled	Disabled, Enabled
Enables or disables the current loop (transducer) input 4 element.				
CLI4 Input Type	4D	64	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 4 input type.				
CLI4 Input Label	4D	66	CLIO Input 4	Editable 16 character string
Current loop 4 input description. The minimum and maximum settings define the range but they have no units. The user can use the label to enter the transducer function and unit of measurement, e.g. Power MW, which is used in the Measurements 3 menu to describe the CLI2 measurement.				
CLI4 Minimum	4D	68	0	-9999 to 9999 step 0.1
Current loop input 4 minimum setting. Defines the lower range of the physical or electrical quantity measured by the transducer.				
CLI4 Maximum	4D	6A	100	-9999 to 9999 step 0.1
Current loop input 4 maximum setting. Defines the upper range of the physical or electrical quantity measured by the transducer.				
CLI4 Alarm	4D	6C	Disabled	Disabled, Enabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Enables or disables the current loop input 4 alarm element.				
CLI4 Alarm Fn	4D	6E	Over	0 = Under, 1 = Over
Operating mode of the current loop input 4 alarm element.				
CLI4 Alarm Set	4D	70	50	CLI4 Minimum to CLI4 Maximum step 0.1
Pick-up setting for the current loop input 4 alarm element.				
CLI4 Alarm Delay	4D	72	1 s	0 s to 100 s step 100 ms
Operating time-delay setting of current loop input 4 alarm element.				
CLI4 Trip	4D	74	Disabled	Disabled, Enabled
Enables or disables the current loop input 4 trip element.				
CLI4 Trip Fn	4D	76	Over	0 = Under, 1 = Over
Operating mode of the current loop input 4 trip element.				
CLI4 Trip Set	4D	78	60	CLI4 Minimum to CLI4 Maximum step 0.1
Pick-up setting for the current loop input 4 trip element.				
CLI4 Trip Delay	4D	7A	0 s	0 s to 100 s step 100 ms
Operating time-delay setting of current loop input 4 trip element.				
CLI4 I< Alarm	4D	7C	Disabled	Disabled, Enabled
Enables or disables the current loop input 4 undercurrent element used to supervise the 4-20mA input only.				
CLI4 I< Alm Set	4D	7E	0.0035 A	From 0 A to 4mA step 0.1mA
Pick-up setting for the current loop input 4 undercurrent element. (4 - 20 mA input only).				
CLIO Output 1	4D	A0	Disabled	Disabled, Enabled
Enable or disables the current loop (transducer) output 1 element.				
CLO1 Output Type	4D	A2	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 1 output type				
CLO1 Set Values	4D	A4	Primary	Primary, Secondary
This setting controls if the measured values via current loop output 1 are Primary or Secondary values.				
CLO1 Parameter	4D	A6	IA Magnitude	See CLIO Output Measurementt table
This setting defines the measured quantity assigned to current loop output 1.				
CLO1 Minimum	4D	A8	0 A	From 0 A to 4800 A step 3 A
Current loop output 1 minimum setting. Defines the lower range of the measurement.				
CLO1 Maximum	4D	AA	360 A	From 0 A to 4800 A step 3 A
Current loop output 1 maximum setting. Defines the upper range of the measurement.				
CLIO Output 2	4D	B0	Disabled	Disabled, Enabled
Enable or disables the current loop (transducer) output 2 element.				
CLO2 Output Type	4D	B2	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 2 output type				
CLO2 Set Values	4D	B4	Primary	Primary, Secondary
This setting controls if the measured values via current loop output 2 are Primary or Secondary values.				
CLO2 Parameter	4D	B6	IB Magnitude	See CLIO Output Measurementt table
This setting defines the measured quantity assigned to current loop output 2.				
CLO2 Minimum	4D	B8	0 A	From 0 A to 4800 A step 3 A
Current loop output 2 minimum setting. Defines the lower range of the measurement.				
CLO2 Maximum	4D	BA	360 A	From 0 A to 4800 A step 3 A

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Current loop output 2 maximum setting. Defines the upper range of the measurement.				
CLIO Output 3	4D	C0	Disabled	Disabled, Enabled
Enable or disables the current loop (transducer) output 3 element.				
CLO3 Output Type	4D	C2	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 3 output type				
CLO3 Set Values	4D	C4	Primary	Primary, Secondary
This setting controls if the measured values via current loop output 3 are Primary or Secondary values.				
CLO3 Parameter	4D	C6	IC Magnitude	See CLIO Output Measurementt table
This setting defines the measured quantity assigned to current loop output 3.				
CLO3 Minimum	4D	C8	0 A	From 0 A to 4800 A step 3 A
Current loop output 3 minimum setting. Defines the lower range of the measurement.				
CLO3 Maximum	4D	CA	360 A	From 0 A to 4800 A step 3 A
Current loop output 3 maximum setting. Defines the upper range of the measurement.				
CLIO Output 4	4D	D0	Disabled	Disabled, Enabled
Enable or disables the current loop (transducer) output 4 element.				
CLO4 Output Type	4D	D2	4-20mA	0 = 0-1mA, 1 = 0-10mA, 2 = 0-20mA, 3 = 4-20mA
Current loop 4 output type				
CLO4 Set Values	4D	D4	Primary	Primary, Secondary
This setting controls if the measured values via current loop output 4 are Primary or Secondary values.				
CLO4 Parameter	4D	D6	IN Measured Mag IN Derived Mag	See CLIO Output Measurementt table
This setting defines the measured quantity assigned to current loop output 4.				
CLO4 Minimum	4D	D8	0 A	From 0 A to 4800 A step 3 A
Current loop output 4 minimum setting. Defines the lower range of the measurement.				
CLO4 Maximum	4D	DA	1.2A	From 0 A to 16 A step 10 mA
Current loop output 4 maximum setting. Defines the upper range of the measurement.				

Table 29 - Current loop inputs and outputs settings

The CLIO output conversion task runs every 50 ms and the refresh interval for the output measurements is nominally 50 ms. The exceptions are marked with an asterisk in the table of current loop output parameters below. Those exceptional measurements are updated once every second.

Current loop output parameters are shown in following table.

Current loop output parameter	Abbreviation	Units	Range	Step	Default min.	Default max.
Current Magnitude	IA Magnitude IB Magnitude IC Magnitude IN Measured Mag. (P342) IN-1 Measured Mag. (P343/P344/P345) IN-2 Measured Mag. (P343/P344/P345) IA Diff 2H (P343/P344/P345) IB Diff 2H (P343/P344/P345) IC Diff 2H (P343/P344/P345) IA Diff 5H (P343/P344/P345) IB Diff 5H (P343/P344/P345) IC Diff 5H (P343/P344/P345)	A	0 to 16A	0.01A	0A	1.2A
Sensitive Current Input Magnitude	I Sen Magnitude	A	0 to 2A	0.01A	0A	1.2A
Phase Sequence Current Components	I1 Magnitude I2 Magnitude I0 Magnitude	A	0 to 16A	0.01A	0A	1.2A
RMS Phase Currents	IA RMS* IB RMS* IC RMS*	A	0 to 16A	0.01A	0A	1.2A
P-P Voltage Magnitude	VAB Magnitude VBC Magnitude VCA Magnitude	V	0 to 200 V	0.1 V	0 V	140 V
P-N voltage Magnitude	VAN Magnitude VBN Magnitude VCN Magnitude	V	0 to 200 V	0.1 V	0 V	80 V
Neutral Voltage Magnitude	VN1 Measured Mag. VN Derived Mag. VN2 Measured Mag. (P344/P345)	V	0 to 200 V	0.1 V	0 V	80 V
3rd Harmonic Neutral Voltage	VN 3rd Harmonic	V	0 to 200 V	0.1 V	0 V	80 V
Phase Sequence Voltage Components	V1 Magnitude* V2 Magnitude V0 Magnitude	V	0 to 200 V	0.1 V	0 V	80 V
RMS Phase Voltages	VAN RMS* VBN RMS* VCN RMS*	V	0 to 200 V	0.1 V	0 V	80 V
Frequency	Frequency	Hz	0 to 70 Hz	0.01 Hz	45 Hz	65 Hz
3 Ph Active Power	Three-Phase Watts*	W	-6000 W to 6000 W	1 W	0 W	300 W
3 Ph Reactive Power	Three-Phase Vars*	Var	-6000 Var to 6000 Var	1 Var	0 Var	300 Var
3 Ph Apparent Power	Three-Phase VA*	VA	0 to 6000 VA	1 VA	0 VA	300 VA
3 Ph Power Factor	3Ph Power Factor*	-	-1 to 1	0.01	0	1
Single-Phase Active Power	A Phase Watts* B Phase Watts* C Phase Watts*	W	-2000 W to 2000 W	1 W	0 W	100 W
Single-Phase Reactive Power	A Phase Vars* B Phase Vars* C Phase Vars*	Var	-2000 Var to 2000 Var	1 Var	0 Var	100 Var

Current loop output parameter	Abbreviation	Units	Range	Step	Default min.	Default max.
Single-Phase Apparent Power	A Phase VA* B Phase VA* C Phase VA*	VA	0 to 2000 VA	1 VA	0 VA	100 VA
Single-Phase Power Factor	APh Power Factor* BPh Power Factor* CPh Power Factor*		-1 to 1	0.01	0	1
Three-Phase Current Demands	IA Fixed Demand* IB Fixed Demand* IC Fixed Demand* IA Roll Demand* IB Roll Demand* IC Roll Demand* IA Peak Demand* IB Peak Demand* IC Peak Demand*	A	0 to 16A	0.01A	0A	1.2A
3Ph Active Power Demands	3Ph W Fix Demand* 3Ph W Roll Dem* 3Ph W Peak Dem*	W	-6000 W to 6000 W	1 W	0 W	300 W
3Ph Reactive Power Demands	3Ph Vars Fix Dem* 3Ph Var Roll Dem* 3Ph Var Peak Dem*	Var	-6000 Var to 6000 Var	1 Var	0 Var	300 Var
Rotor Thermal State	NPS Thermal	%	0 to 200	0.01	0	120
Stator Thermal State	Thermal Overload	%	0 to 200	0.01	0	120
RTD Temperatures	RTD 1* RTD 2* RTD 3* RTD 4* RTD 5* RTD 6* RTD 7* RTD 8* RTD 9* RTD 10*	°C	-40°C to 300°C	0.1°C	0°C	200°C
Current Loop Inputs	CL Input 1 CL Input 2 CL Input 3 CL input 4	-	-9999 to 9999	0.1	0	9999
Flux, V/Hz	Volts/Hz	V/Hz	0-20	0.01	0	4
df/dt	df/dt	Hz/s	-10 to 10 Hz/s	0.01 Hz/s	-1 Hz/s	1 Hz/s
Check Synch Voltages	C/S Voltage Mag C/S Bus Gen-Mag	V	0 to 200 V	0.1 V	0 V	80 V
Slip Frequency	Slip frequency	Hz	0 to 70 Hz	0.01 Hz	-0.5 Hz	0.5 Hz

Table 30 - Current loop outputs units and setting range

Note 1 *For measurements marked with an asterisk, the internal refresh rate is nominally 1 s, others are 0.5 power system cycle or less.*

Note 2 *The polarity of Watts, Vars and power factor is affected by the Measurements Mode setting.*

Note 3 *These settings are for nominal 1A and 100/120 V versions only. For other nominal versions they need to be multiplied accordingly.*

Note 4 *For the P343/P344/P345, the IA/IB/IC Current magnitudes are IA-1 Magnitude, IB-1 Magnitude, IC-1 Magnitude.*

4.28 System Checks (Check Sync. Function)

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

The VN1 input is used for P342/P343 and the VN2 input is used for P344. Since the input is shared, neutral displacement elements using the same input cannot be used if check synch is enabled. The P345 has a dedicated input for the check synch voltage.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
GROUP 1 SYSTEM CHECKS	4E	00		
GROUP 1 SYSTEM CHECKS				
VOLTAGE MONITORS	4E	01		
Live Voltage	4E	02	32*V1	From 1*V1 to 132*V1 step 0.5*V1
Minimum voltage setting above which a generator or busbar is recognized as being ‘Live’.				
Dead Voltage	4E	03	13*V1	From 1*V1 to 132*V1 step 0.5*V1
Maximum voltage setting below which a generator or busbar is recognized as being ‘Dead’.				
Gen UnderVoltage	4E	04	54*V1	From 1*V1 to 132*V1 step 0.5*V1
Undervoltage setting above which the generator voltage must be satisfied for the Check Sync. condition if V< is selected in the CS Voltage Block cell.				
Gen Over Voltage	4E	05	130*V1	From 1*V1 to 185*V1 step 0.5*V1
Overvoltage setting which the generator voltage must be satisfied for the Check Sync. condition if V> is selected in the CS Voltage Block cell.				
Bus UnderVoltage	4E	06	54*V1	From 10*V1 to 185*V1 step 0.5*V1
Undervoltage setting above which the busbar voltage must be satisfied for the Check Sync. condition if V< is selected in the CS Voltage Block cell..				
Bus Over Voltage	4E	07	130*V1	From 60*V1 to 185*V1 step 0.5*V1
Overvoltage setting below which the busbar voltage must be satisfied for the Check Sync. condition if V> is selected in the CS Voltage Block cell.				
CS Diff Voltage	4E	08	6.5*V1	From 1*V1 to 132*V1 step 0.5*V1
Voltage magnitude difference setting between the generator and busbar volts below which the generator and bus voltage difference must be satisfied for the Check Sync. condition if selected in the CS Voltage Block cell.				
CS Voltage Block	4E	09	V<	V<, V>, V Diff>, V< and V>, V< and V Diff>, V> and V Diff>, V< V> V Diff>
Selects the undervoltage(V<), overvoltage (V>) and voltage difference (Vdiff>) voltage blocking options for the generator and bus voltages that must be satisfied in order for the Check Sync. conditions to be satisfied.				
Gen Under Freq	4E	0A	49.5 Hz	From 45 HZ to 65 HZ step 0.01 HZ
Underfrequency setting for the generator. This setting only affects DDB 1347 Freq Low which indicates the generator frequency is lower than the Gen Under Freq setting.				
Gen Over Freq	4E	0B	50.5 Hz	From 45 HZ to 65 HZ step 0.01 HZ
Overfrequency setting for the generator. This setting only affects DDB 1348 Freq High which indicates the generator frequency is higher than the Gen Over Freq setting				
CHECK SYNC	4E	10		
CS1 Status	4E	11	Enabled	Disabled, Enabled
Enables or disables the first stage check sync. element.				
CS1 Phase Angle	4E	12	20 °	From 5 º to 90 º step 1º
Maximum phase angle difference setting between the line and bus voltage for the first stage check sync. element phase angle criteria to be satisfied.				
CS1 Slip Control	4E	13	Frequency only	None, Timer only, Frequency only, Frequency+Timer

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Slip control method - 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: (2 x A) / (T x 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 30deg and Timer setting 3.3 sec, the “slipping” vector has to remain within +-30deg of the reference vector for at least 3.3 seconds. Therefore a synch check output will not be given if the slip is greater than 2 x 30deg 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	4E	14	50 mHz	From 0.01 Hz to 1 Hz step 0.01 Hz
Maximum frequency difference setting between the generator and bus voltage for the first stage check sync. element slip frequency to be satisfied.				
CS1 Slip Timer	4E	15	1 s	0 s to 99 s step 10 ms
Minimum operating time-delay setting for the first stage check sync. element.				
CS2 Status	4E	16	Disabled	Disabled, Enabled
Enable or disables the second stage check sync. element.				
CS2 Phase Angle	4E	17	20 °	From 5 º to 90 º step 1º
Maximum phase angle difference setting between the line and bus voltage for the second stage check sync. element phase angle criteria to be satisfied.				
CS2 Slip Control	4E	18	Frequency only	None, Timer only, Frequency only, Frequency+Timer, Freq + CB Comp
Slip control method - 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: A / (T x 360) Hz. for Check Sync. 2, or where A = Phase angle setting (deg) T = Slip timer setting (seconds) For Check Sync 2, with Phase Angle setting 10deg and Timer setting 0.1 sec, the slipping vector has to remain within 10deg of the reference vector, with the angle decreasing, for 0.1 sec. When the angle passes through zero and starts to increase, the synch check output is blocked. Therefore an output will not be given if slip is greater than 10deg 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 Frequency + CB (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.				
CS2 Slip Freq	4E	19	50 mHz	From 0.01 Hz to 1 Hz step 0.01 Hz
Slip frequency setting for the second stage check sync. element.				
CS2 Slip Timer	4E	1A	1 s	0 s to 99 s step 10 ms
Second stage Check Sync. slip timer setting.				
SYSTEM SPLIT	4E	20		
SS Status	4E	21	Enabled	Disabled, Enabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Enables or disables the system split function.				
SS Phase Angle	4E	22	120 °	From 90 º to 175 º step 1º
Maximum phase angle difference setting between the generator and bus voltage, which must be exceeded, for the System Split condition to be satisfied.				
SS Under V Block	4E	23	Enabled	Disabled, Enabled
Activates the system split undervoltage block criteria				
SS UnderVoltage	4E	24	54*V1	From 10*V1 to 132*V1 step 0.5*V1
Undervoltage setting above which the generator and bus voltage must be satisfied for the System Split condition.				
SS Timer	4E	25	1 s	0 s to 99 s step 10 ms
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	4E	30	50 ms	0 s to 500 ms step 1 ms
Circuit breaker closing time setting used in the second stage Check Sync criteria to compensate for the breaker closing time if selected.				

Table 31 - System checks settings

5 CONTROL AND SUPPORT SETTINGS

The control and support settings are part of the main menu and are used to configure the relays global configuration. It includes the following submenu settings.

- 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

5.1 Security Configuration

Courier Text	Col	Row	Default Setting	Available Setting
Description				
SECURITY CONFIG	25	00		
This column contains settings for Security Configuration				
User Banner	25	01	ACCESS ONLY FOR AUTHORISED USERS	Not Settable
This banner is one of the default display options				
Attempts Limit	25	02	5	Special cells, not settable except for configuring via SAT for CSL1 models
Adjust the number of attempts to enter a valid password. Fixed at 5 for CSL0 models. SAT can configure from 1 to 99 for CSL1 models.				
Blocking Timer	25	04	4	Special cells, not settable except for configuring via SAT for CSL1 models
Adjust the blocking timer (minutes) after a password blocking. Once the password is blocked, this blocking timer is initiated. Only after the blocking timer has expired will access to the interface be unblocked, whereupon the attempts counter is reset to zero. Fixed at 4 for CSL0 models. SAT can configure from 1 to 1440 for CSL1 models.				
Front Port	25	05	Enabled	0 = Disabled or 1 = Enabled
Enable or disable the front port access. To prevent accidental disbling of a port, a warning message "FRONT PORT TO BE DISABLED, CONFIRM" is required to be disabled.				
Rear Port 1	25	06	Enabled	0 = Disabled or 1 = Enabled
Enable or disable the rear port 1 access. To prevent accidental disbling of a port, a warning message "REAR PORT 1 TO BE DISABLED, CONFIRM" is required to be disabled.				
Rear Port 2	25	07	Enabled	0 = Disabled or 1 = Enabled
When fitted, enable or disable the rear port 2 access. To prevent accidental disabling of a port, a warning message "REAR PORT 2 TO BE DISABLED, CONFIRM" is required to be disabled.				
ETH Port 1	25	08	Enabled	0 = Disabled or 1 = Enabled
Enable or disable Ethernet logical port 1 access. Note: if this port is enabled or disabled, the Ethernet card will reboot. Single port Ethernet card or Redundant Ethernet card with Comm Mode=PRP or HSR				
ETH Port 1/2	25	09	Enabled	0 = Disabled or 1 = Enabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Enable or disable the Ethernet logical port 1/2 access. Note: if these ports are enabled or disabled, the Ethernet card will reboot. Redundant Ethernet card with Comm Mode=Dual IP				
ETH Port 2/3	25	0A	Enabled	0 = Disabled or 1 = Enabled
Enable or disable the Ethernet logical port 2/3 access. Note: if these ports are enabled or disabled, the Ethernet card will reboot. Redundanct Ethernet card with Comm Mode=PRP or HSR				
ETH Port 3	25	0B	Enabled	0 = Disabled or 1 = Enabled
Enable or disable the Ethernet logical port 3 access. Note: if this port is enabled or disabled, the Ethernet card will reboot. Redundant Ethernet card with Comm Mode=Dual IP				
Courier Tunnel	25	0C	Enabled	0 = Disabled or 1 = Enabled
Enable or disable Logical Tunnelled Courier Port				
IEC61850 or IEC61850+DNPoE	25	0D	Enabled	0 = Disabled or 1 = Enabled
Enable or disable IEC61850 (and DNPoE for protocol option B or L) services				
Attempts Remain	25	11	5	Not Settable
Indicates the number of attempts remaining to enter a password.				
Blk Time Remain	25	12	0	Not Settable
Indicates the blocking time remaining (in minutes).				
Username 1	25	21		Not Settable
User Name, visible in authorized courier client, only.				
Username 2	25	22		Not Settable
User Name, visible in authorized courier client, only.				
Username 3	25	23		Not Settable
User Name, visible in authorized courier client, only.				
Username 4	25	24		Not Settable
User Name, visible in authorized courier client, only.				
Username 5	25	25		Not Settable
User Name, visible in authorized courier client, only.				
Username 6	25	26		Not Settable
User Name, visible in authorized courier client, only.				
Username 7	25	27		Not Settable
User Name, visible in authorized courier client, only.				
Username 8	25	28		Not Settable
User Name, visible in authorized courier client, only.				
Username 9	25	29		Not Settable
User Name, visible in authorized courier client, only.				
Username 10	25	2A		Not Settable
User Name, visible in authorized courier client, only.				
Username 11	25	2B		Not Settable
User Name, visible in authorized courier client, only.				
Username 12	25	2C		Not Settable
User Name, visible in authorized courier client, only.				
Username 13	25	2D		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
User Name, visible in authorized courier client, only.				
Username 14	25	2E		Not Settable
User Name, visible in authorized courier client, only.				
Username 15	25	2F		Not Settable
User Name, visible in authorized courier client, only.				
Security Code	25	FE		Not Settable
Indicates the security code (user interface only). The security code is a read-only random 12-digit number. This Security Code should be noted for password recovery and the relay should not be power cycled until the reset RBAC code is entered.				
Reset RBAC	25	FF		From 33 to 122 step 1
Recovery password obtained from Schneider Electric can be entered here to restore the default RBAC. (user interface only)				

Table 32 - Security configuration settings

5.2 System Data

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

Courier Text	Col	Row	Default Setting	Available Setting
Description				
SYSTEM DATA	00	00		
This column contains general system settings				
Language	00	01	English	English, Français, Deutsch, Español, Русский, 中文 (UI only)
The default language used by the device. Selectable as English, French, German, Russian, Spanish and Chinese. Chinese is UI only.				
Sys Fn Links	00	03	0(bin)	Bit 00 = Trip LED S/Reset
Setting to allow the fixed function trip LED to be self resetting (set to 1 to extinguish the LED after a period of healthy restoration of load current).				
Description	00	04	MiCOM P34x	32 to 234 step 1
Editable 16-character description of the unit, where x = 2 for P342, 3 for P343, 4 for P344, 5 for P345				
Plant Reference	00	05	MiCOM	32 to 234 step 1
Plant description: Can be edited				
Model Number	00	06	Model Number	<Model number>
Displays the model number. This can not be edited.				
Serial Number	00	08	Serial Number	<Serial number>
Displays the serial number. This can not be edited.				
Frequency	00	09	50	50 or 60
Sets the mains frequency				
Comms Level	00	0A	2	<conformance level displayed>
Displays the conformance of the relay to the Courier Level 2 comms.				
Relay Address	00	0B	255 1 1 1	0 to 255 (Courier) 1 to 247 (Modbus) 0 to 254 (IEC60870) 0 to 65519 (DNP3.0)

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Set the first rear port relay address. Build = Courier (Address available via LCD) Build = Modbus (Address available via LCD) Build = CS103 (Address available via LCD) Build = DNP3.0 (Address available via LCD)				
Plant Status	00	0C		Not Settable
Displays the circuit breaker plant status. Bit 00 CB1 Open, Bit 01 CB1 Closed				
Control Status	00	0D		Not used
Not used				
Active Group	00	0E		Not Settable
Displays the active settings group.				
CB Trip/Close	00	10	No Operation	0 = No Operation, 1 = Trip, 2 = Close
Supports trip and close commands if enabled in the Circuit Breaker Control menu.				
Software Ref. 1	00	11		<Software Ref. 1>
Displays the relay software version including protocol and relay model.				
Software Ref. 2	00	12		<Software Ref. 2>
Relay Ethernet card software reference. Visible when Ethernet card fitted.				
NIC Platform Ref	00	14		<NIC platform reference>
Displays the relay NIC platform reference. Visible when Ethernet card fitted.				
IEC61850 Edition	00	15	2	1 or 2
Selects IEC 61850 Editions, Edition 1 or Edition 2. This setting can only be changed via HMI and the changes will cause the Ethernet board to reboot.				
ETH COMM Mode	00	16	Dual IP	Dual IP, PRP, HSR
Sets the redundancy protocol. This setting can only be changed via the HMI and the changes will cause the Ethernet board to reboot.				
Opto I/P Status	00	20		Not Settable
Display the status of the available opto inputs fitted.				
Relay O/P Status	00	21		Not Settable
Displays the status of the output relays (number of output relays depending on the model).				
Alarm Status 1	00	22		Not Settable
This menu cell displays the status of the first 32 alarms as a binary string. 1 indicates an ON state and 0 an OFF state. Includes fixed and user settable alarms.				
Opto I/P Status	00	30		Not Settable
Displays the status of opto-isolated inputs (number of opto inputs depending on the model).				
Relay O/P Status	00	40		Not Settable
Displays the status of the output relays (number of output relays depending on the model).				
Alarm Status 1	00	50		Not Settable
This menu cell displays the status of the first 32 alarms as a binary string. 1 indicates an ON state and 0 an OFF state.				
Alarm Status 2	00	51		Not Settable
This menu cell displays the status of the second 32 alarms as a binary string.1 indicates an ON state and 0 an OFF state.				
Alarm Status 3	00	52		Not Settable
This menu cell displays the status of the third 32 alarms as a binary string. 1 indicates an ON state and 0 an OFF state. Assigned specifically for platform alarms.				
Usr Alarm Status	00	53		Not Settable
This menu cell displays the status of the 32 user alarms as a binary string. 1 indicates an ON state and 0 an OFF state.				
Access Level	00	D0	ENGINEER	Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Display the Role(s) of the current logged in user, if no one logged in, it shall be "NONE".				
New Eng.Level PW	00	D3		ASCII 33 to 122
Allows user to change password for EngineerLevel. Visible on UI only.				
New Op.Level PW	00	D4		ASCII 33 to 122
Allows user to change password for OperatorLevel. Visible on UI only.				
Security Feature	00	DF	3	Not Settable
Displays the level of cyber security implemented				
Password	00	E1		<Password>
Used to send encrypted password. Not visible on UI.				
Encryption Salt	00	E5		<Encryption Salt>
Random data used with encrypted password. Not visible on UI.				
Enter username	00	F1		<User Name>
User selection for login. Not visible on UI.				
Number of users	00	F2	2	Not Settable
Shows the number of users configured within the relays RBAC.				
New UI pwd	00	F3		<Second Simple Password>
Hidden cell reserved for second password modification. Not in use currently.				
New password	00	F4		<Encrpted Password>
Allow password change if engineer or operator logged in and CSL0 model. Not visible on UI.				

Table 33 - System data

5.3 View Records

This menu provides information on event, fault and maintenance records. The relay records the last 512 events, 20 fault records and the last ten maintenance records.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
VIEW RECORDS	01	00		
This column contains event, fault and maintenance records				
Select Event	01	01	0	From 0 to 511 step 1
This selects the required event record from all the possible ones that may be stored. A value of 0 corresponds to the latest event, with the maximum value the oldest.				
Menu Cell Ref	01	02		Not Settable
Indicates type of event.				
Time & Date	01	03		Not Settable
Time & Date Stamp for the event given by the internal Real Time Clock.				
Event Text	01	04		Not Settable
Up to 16 Character description of the Event (refer to following sections).				
Event Value	01	05		Not Settable
Up to 32 Bit Binary Flag or integer representative of the Event (refer to following sections).				
Select Fault	01	06	0	From 0 to 20 step 1
This selects the required fault record from the possible 20 that may be stored. A value of 0 corresponds to the latest fault and so on.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Faulted Phase	01	40		Not Settable
Phase initiating fault recorder starts : Start A, Start B, Start C, Trip A, Trip B, Trip C.				
Start Elements1	01	42		Not Settable
Displays the status of the first 32 start signals				
Start Elements2	01	43		Not Settable
Displays the status of the second 32 start signals				
Start Elements3	01	44		Not Settable
Displays the status of the third 32 start signals				
Start Elements4	01	45		Not Settable
Displays the status of the fourth 32 start signals				
Trip Elements1	01	49		Not Settable
Displays the status of the first 32 trip signals				
Trip Elements2	01	4A		Not Settable
Displays the status of the second 32 trip signals				
Trip Elements3	01	4B		Not Settable
Displays the status of the third 32 trip signals				
Trip Elements4	01	4C		Not Settable
Displays the status of the fouth 32 trip signals				
Fault Alarms	01	50		Not Settable
Displays the status of the first 32 fault alarm signals				
Fault Alarms 2	01	51		Not Settable
Displays the status of the second 32 fault alarm signals				
Fault Time	01	55		Not Settable
Displays fault time and date				
Active Group	01	57		Not Settable
Displays active setting group				
System Frequency	01	59		Not Settable
Displays the system frequency				
Fault Duration	01	5B		Not Settable
Displays time from the start or trip until the undercurrent elements indicate the CB is open				
CB Operate Time	01	5E		Not Settable
Displays time from protection trip to undercurrent elements indicating the CB is open				
Relay Trip Time	01	60		Not Settable
Displays time from protection start to protection trip				
IA IA-1	01	62		Not Settable
CT1 Phase A Magnitude. IA is used on P342 while IA-1 applies to P343/P344/P345				
IB IB-1	01	63		Not Settable
CT1 Phase B Magnitude. IB is used on P342 while IB-1 applies to P343/P344/P345				
IC IC-1	01	64		Not Settable
CT1 Phase C Magnitude. IC is used on P342 while IC-1 applies to P343/P344/P345				
VAB	01	65		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Phase A to Phase B voltage Magnitude				
VBC	01	66		Not Settable
Phase B to Phase C voltage Magnitude				
VCA	01	67		Not Settable
Phase C to Phase A voltage Magnitude				
VAN	01	68		Not Settable
Phase A to Neutral Voltage Magnitude				
VBN	01	69		Not Settable
Phase B to Neutral Voltage Magnitude				
VCN	01	6A		Not Settable
Phase C to Neutral Voltage Magnitude				
IA-2	01	70		Not Settable
CT2 Phase A Magnitude (P343/P344/P345)				
IB-2	01	71		Not Settable
CT2 Phase B Magnitude (P343/P344/P345)				
IC-2	01	72		Not Settable
CT2 Phase C Magnitude (P343/P344/P345)				
IA Differential	01	80		Not Settable
Phase A Differential Current (P343/P344/P345)				
IB Differential	01	81		Not Settable
Phase B Differential Current (P343/P344/P345)				
IC Differential	01	82		Not Settable
Phase C Differential Current (P343/P344/P345)				
IA Diff PU	01	83		Not Settable
Phase A Differential PU Current (P343/P344/P345)				
IB Diff PU	01	84		Not Settable
Phase B Differential PU Current (P343/P344/P345)				
IC Diff PU	01	85		Not Settable
Phase C Differential PU Current (P343/P344/P345)				
IA Diff 2H	01	86		Not Settable
Phase A 2nd Harmonic Differential Current (P343/P344/P345)				
IB Diff 2H	01	87		Not Settable
Phase B 2nd Harmonic Differential Current (P343/P344/P345)				
IC Diff 2H	01	88		Not Settable
Phase C 2nd Harmonic Differential Current (P343/P344/P345)				
IA Diff 5H	01	89		Not Settable
Phase A 5th Harmonic Differential Current (P343/P344/P345)				
IB Diff 5H	01	8A		Not Settable
Phase B 5th Harmonic Differential Current (P343/P344/P345)				
IC Diff 5H	01	8B		Not Settable
Phase C 5th Harmonic Differential Current (P343/P344/P345)				
VN Measured VN1 Measured	01	90		Not Settable
Measured Neutral Voltage Magnitude. VN Measured is used on P342/P343 while VN1 Measured applies to P344/P345				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
VN2 Measured	01	92		Not Settable
VN2 Measured Neutral Voltage Magnitude (P344/P345)				
VN Derived	01	94		Not Settable
Derived Neutral Voltage Magnitude				
IN Measured	01	96		Not Settable
Neutral Measured Current Magnitude				
I Sensitive	01	99		Not Settable
Sensitive CT Current Magnitude				
IREF Diff	01	9C		Not Settable
Referenced Differential Current				
IREF Bias	01	9D		Not Settable
Referenced Bias Current				
I2	01	A0		Not Settable
Negative Sequence Current				
V2	01	A2		Not Settable
Negative Sequence Voltage				
3 Phase Watts	01	A6		Not Settable
3 Phase Active Power				
3 Phase VArs	01	A8		Not Settable
3 Phase VArs measurement				
3Ph Power Factor	01	AA		Not Settable
3 Phase Power Factor				
RTD 1	01	B0		Not Settable
RTD 1 Temperature				
RTD 2	01	B1		Not Settable
RTD 2 Temperature				
RTD 3	01	B2		Not Settable
RTD 3 Temperature				
RTD 4	01	B3		Not Settable
RTD 4 Temperature				
RTD 5	01	B4		Not Settable
RTD 5 Temperature				
RTD 6	01	B5		Not Settable
RTD 6 Temperature				
RTD 7	01	B6		Not Settable
RTD 7 Temperature				
RTD 8	01	B7		Not Settable
RTD 8 Temperature				
RTD 9	01	B8		Not Settable
RTD 9 Temperature				
RTD 10	01	B9		Not Settable
RTD 10 Temperature				
df/dt	01	C2		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
df/dt Value				
V Vector Shift	01	C4		Not Settable
Voltage Vector Shift Value				
CLIO Input 1	01	C6		Not Settable
CLIO Input 1				
CLIO Input 2	01	C7		Not Settable
CLIO Input 2				
CLIO Input 3	01	C8		Not Settable
CLIO Input 3				
CLIO Input 4	01	C9		Not Settable
CLIO Input 4				
64S V Magnitude	01	CA		Not Settable
100% Stator Earth Fault Voltage 20Hz injection voltage (P345)				
64S I Magnitude	01	CB		Not Settable
100% Stator Earth Fault Voltage 20Hz injection current (P345)				
64S R primary	01	CC		Not Settable
100% Stator Earth Fault Voltage 20Hz injection resistance (P345)				
64R CL Input	01	CD		Not Settable
Rotor Earth Fault CLIO measurement				
64R R Fault	01	CE		Not Settable
Rotor Earth Fault resistance				
DLR Ambient Temp	01	D0		Not Settable
Dynamic Line Rating Ambient Temperature				
Wind Velocity	01	D1		Not Settable
Wind Velocity				
Wind Direction	01	D2		Not Settable
Wind Direction				
Solar Radiation	01	D3		Not Settable
Solar Radiation				
DLR Ampacity	01	D4		Not Settable
Dynamic Line Rating Ampacity				
DLR CurrentRatio	01	D5		Not Settable
Dynamic Line Rating Current Ratio				
Dyn Conduct Temp	01	D6		Not Settable
Dynamic Conductor Temperature				
Xph Sen Watts	01	DD		Not Settable
Xph Sensitive Active Power				
IA-1 Peak	01	E4		Not Settable
CT1 Phase A Peak Through Fault Current Magnitude				
IB-1 Peak	01	E5		Not Settable
CT1 Phase B Peak Through Fault Current Magnitude				
IC-1 Peak	01	E6		Not Settable
CT1 Phase C Peak Through Fault Current Magnitude				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
IA-1 2t	01	E7		Not Settable
CT1 Phase A Through Fault I2t				
IB-1 2t	01	E8		Not Settable
CT1 Phase B Through Fault I2t				
IC-1 2t	01	E9		Not Settable
CT1 Phase C Through Fault I2t				
IA-2 Peak	01	EA		Not Settable
CT2 Phase A Peak Through Fault Current Magnitude (P343/P344/P345)				
IB-2 Peak	01	EB		Not Settable
CT2 Phase B Peak Through Fault Current Magnitude (P343/P344/P345)				
IC-2 Peak	01	EC		Not Settable
CT2 Phase C Peak Through Fault Current Magnitude (P343/P344/P345)				
IA-2 2t	01	ED		Not Settable
CT2 Phase A Through Fault I2t (P343/P344/P345)				
IB-2 2t	01	EE		Not Settable
CT2 Phase B Through Fault I2t (P343/P344/P345)				
IC-2 2t	01	EF		Not Settable
CT2 Phase C Through Fault I2t (P343/P344/P345)				
Select Maint	01	F0	0	0 to 9, step 1
This selects the required maintenance record from that may be stored. A value of 0 corresponds to the latest record and so on.				
Maint Text	01	F1		Not Settable
Up to 16 Character description of the occurrence (refer to following sections).				
Maint Type	01	F2		Not Settable
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.				
Maint Data	01	F3		Not Settable
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.				
Evt Iface Source	01	FA		Not Settable
Interface on which the event was logged				
Evt Access Level	01	FB		Not Settable
Any security event that indicates that it came from an interface action, such as disabling a port, will also record the access level of the interface that initiated the event. This will be recorded in the 'Event State' field of the event.				
Evt Extra Info	01	FC		Not Settable
This cell provides supporting information for the event and can vary between the different event types.				
Evt Unique Id	01	FE		Not Settable
Each event will have a unique event id. The event id is a 32 bit unsigned integer that is incremented for each new event record and is stored in the record in battery-backed memory (BBRAM). The current event id must be non-volatile so as to preserve it du				
Reset Indication	01	FF	No	No or Yes
This serves to reset the trip LED indications provided that the relevant protection element has reset, to reset all LED and relays latched in the PSL, and to reset the latched alarms.				

Table 34 - View records settings

5.4 Measurements 1

This menu provides measurement information.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASUREMENTS 1	02	00		
This column contains measurement parameters				
IA Magnitude IA-1 Magnitude	02	01		Not Settable
IA-1 Magnitude measurement. IA Magnitude is used on P342 while IA-1 Magnitude applies to P343/P344/P345				
IA Phase Angle IA-1 Phase Angle	02	02		Not Settable
IA-1 Phase Angle measurement. IA Phase Angle is used on P342 while IA-1 Phase Angle applies to P343/P344/P345				
IB Magnitude IB-1 Magnitude	02	03		Not Settable
IB-1 Magnitude measurement. IB Magnitude is used on P342 while IB-1 Magnitude applies to P343/P344/P345				
IB Phase Angle IB-1 Phase Angle	02	04		Not Settable
IB-1 Phase Angle measurement. IB Phase Angle is used on P342 while IB-1 Phase Angle applies to P343/P344/P345				
IC Magnitude IC-1 Magnitude	02	05		Not Settable
IC-1 Magnitude measurement. IC Magnitude is used on P342 while IC-1 Magnitude applies to P343/P344/P345				
IC Phase Angle IC-1 Phase Angle	02	06		Not Settable
IC-1 Phase Angle measurement. IC Phase Angle is used on P342 while IC-1 Phase Angle applies to P343/P344/P345				
IN Measured Mag	02	07		Not Settable
IN Measured Magnitude measurement				
IN Measured Ang	02	08		Not Settable
IN Measured Angle measurement				
IN Derived Mag IN-1 Derived Mag	02	09		Not Settable
IN Derived Magnitude measurement. IN Derived Mag is used on P342 while IN-1 Derived Mag applies to P343/P344/P345				
IN Derived Angle	02	0A		Not Settable
IN Derived Angle measurement				
Isen Magnitude	02	0B		Not Settable
Isen Magnitude measurement				
Isen Angle	02	0C		Not Settable
Isen Angle measurement				
I1 Magnitude	02	0D		Not Settable
I1-1 Magnitude measurement				
I2 Magnitude	02	0E		Not Settable
I2-1 Magnitude measurement				
I0 Magnitude	02	0F		Not Settable
I0-1 Magnitude measurement				
IA RMS	02	10		Not Settable
IA RMS measurement				
IB RMS	02	11		Not Settable
IB RMS measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
IC RMS	02	12		Not Settable
IC RMS measurement				
IN-2 Derived Mag	02	13		Not Settable
IN-2 Derived Magnitude measurement (P343/P344/P345)				
VAB Magnitude	02	14		Not Settable
VAB Magnitude measurement				
VAB Phase Angle	02	15		Not Settable
VAB Phase Angle measurement				
VBC Magnitude	02	16		Not Settable
VBC Magnitude measurement				
VBC Phase Angle	02	17		Not Settable
VBC Phase Angle measurement				
VCA Magnitude	02	18		Not Settable
VCA Magnitude measurement				
VCA Phase Angle	02	19		Not Settable
VCA Phase Angle measurement				
VAN Magnitude	02	1A		Not Settable
VAN Magnitude measurement				
VAN Phase Angle	02	1B		Not Settable
VAN Phase Angle measurement				
VBN Magnitude	02	1C		Not Settable
VBN Magnitude measurement				
VBN Phase Angle	02	1D		Not Settable
VBN Phase Angle measurement				
VCN Magnitude	02	1E		Not Settable
VCN Magnitude measurement				
VCN Phase Angle	02	1F		Not Settable
VCN Phase Angle measurement				
VN Measured Mag VN1 Measured Mag	02	20		Not Settable
VN Measured Mag measurement. VN Measured Mag is used on P342/P343 while VN1 Measured Mag applies to P344/P345				
VN Measured Ang VN1 Measured Ang	02	21		Not Settable
VN Measured Angle measurement. VN Measured Ang is used on P342/P343 while VN1 Measured Ang applies to P344/P345				
VN Derived Mag	02	22		Not Settable
VN Derived Mag measurement				
VN Derived Ang	02	23		Not Settable
VN Derived Angle measurement				
V1 Magnitude	02	24		Not Settable
V1 Magnitude measurement				
V2 Magnitude	02	25		Not Settable
V2 Magnitude measurement				
V0 Magnitude	02	26		Not Settable
V0 Magnitude measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
VAN RMS	02	27		Not Settable
VAN RMS measurement				
VBN RMS	02	28		Not Settable
VBN RMS measurement				
VCN RMS	02	29		Not Settable
VCN RMS measurement				
Frequency	02	2D		Not Settable
Frequency measurement				
I1 Magnitude	02	40		Not Settable
I1 Magnitude measurement				
I1 Phase Angle	02	41		Not Settable
I1 Phase Angle measurement				
I2 Magnitude	02	42		Not Settable
I2 Magnitude measurement				
I2 Phase Angle	02	43		Not Settable
I2 Phase Angle measurement				
I0 Magnitude	02	44		Not Settable
I0 Magnitude measurement				
I0 Phase Angle	02	45		Not Settable
I0 Phase Angle measurement				
V1 Magnitude	02	46		Not Settable
V1 Magnitude measurement				
V1 Phase Angle	02	47		Not Settable
V1 Phase Angle measurement				
V2 Magnitude	02	48		Not Settable
V2 Magnitude measurement				
V2 Phase Angle	02	49		Not Settable
V2 Phase Angle measurement				
V0 Magnitude	02	4A		Not Settable
V0 Magnitude measurement				
V0 Phase Angle	02	4B		Not Settable
V0 Phase Angle measurement				
VN2 Measured Mag	02	50		Not Settable
VN2 Measured Magnitude measurement (P344/P345)				
VN2 Measured Ang	02	51		Not Settable
VN2 Measured Angle measurement (P344/P345)				
C/S Voltage Mag	02	70		Not Settable
C/S Voltage Magnitude measurement				
C/S Voltage Ang	02	71		Not Settable
C/S Voltage Angle measurement				
CS Gen-Bus Mag	02	72		Not Settable
Visible if System Checks enabled, CS Gen-Bus Magnitude measurement				
CS Gen-Bus Ang	02	73		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Visible if System Checks enabled, CS Gen-Bus Angle measurement				
Slip Frequency	02	74		Not Settable
Visible if System Checks enabled, Slip Frequency measurement				
CS Frequency	02	75		Not Settable
CS Frequency measurement				

Table 35 - Measurement 1 menu

5.5 Measurements 2

This menu provides measurement information.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASUREMENTS 2	03	00		
This column contains measurement parameters				
A Phase Watts	03	01		Not Settable
A Phase Watts measurement				
B Phase Watts	03	02		Not Settable
B Phase Watts measurement				
C Phase Watts	03	03		Not Settable
C Phase Watts measurement				
A Phase VArs	03	04		Not Settable
A Phase VArs measurement				
B Phase VArs	03	05		Not Settable
B Phase VArs measurement				
C Phase VArs	03	06		Not Settable
C Phase VArs measurement				
A Phase VA	03	07		Not Settable
A Phase VA measurement				
B Phase VA	03	08		Not Settable
B Phase VA measurement				
C Phase VA	03	09		Not Settable
C Phase VA measurement				
3 Phase Watts	03	0A		Not Settable
3 Phase Watts measurement				
3 Phase VArs	03	0B		Not Settable
3 Phase VArs measurement				
3 Phase VA	03	0C		Not Settable
3 Phase VA measurement				
NPS Power S2	03	0D		Not Settable
NPS Power S2 measurement				
3Ph Power Factor	03	0E		Not Settable
3Ph Power Factor measurement				
APh Power Factor	03	0F		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
APh Power Factor measurement				
BPh Power Factor	03	10		Not Settable
BPh Power Factor measurement				
CPh Power Factor	03	11		Not Settable
CPh Power Factor measurement				
3Ph WHours Fwd	03	12		Not Settable
3Ph WHours Fwd measurement				
3Ph WHours Rev	03	13		Not Settable
3Ph WHours Rev measurement				
3Ph VArHours Fwd	03	14		Not Settable
3Ph VArHours Fwd measurement				
3Ph VArHours Rev	03	15		Not Settable
3Ph VArHours Rev measurement				
3Ph W Fix Demand	03	16		Not Settable
3Ph W Fix Demand measurement				
3Ph VArs Fix Dem	03	17		Not Settable
3Ph VArs Fix Dem measurement				
IA Fixed Demand	03	18		Not Settable
IA Fix Demand measurement				
IB Fixed Demand	03	19		Not Settable
IB Fix Demand measurement				
IC Fixed Demand	03	1A		Not Settable
IC Fix Demand measurement				
3 Ph W Roll Dem	03	1B		Not Settable
3 Ph W Roll Dem measurement				
3Ph VArs RollDem	03	1C		Not Settable
3Ph VArs RollDem measurement				
IA Roll Demand	03	1D		Not Settable
IA Roll Demand measurement				
IB Roll Demand	03	1E		Not Settable
IB Roll Demand measurement				
IC Roll Demand	03	1F		Not Settable
IC Roll Demand measurement				
3Ph W Peak Dem	03	20		Not Settable
3Ph W Peak Dem measurement				
3Ph VAr Peak Dem	03	21		Not Settable
3Ph VAr Peak Dem measurement				
IA Peak Demand	03	22		Not Settable
IA Peak Demand measurement				
IB Peak Demand	03	23		Not Settable
IB Peak Demand measurement				
IC Peak Demand	03	24		Not Settable
IC Peak Demand measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Reset Demand	03	25	No	No or Yes
Reset Demand				
NPS Power S2 CT2	03	26		Not Settable
NPS Power S2 CT2 measurement (P343/P344/P345)				

Table 36 - Measurement 2 menu

5.6 Measurements 3

This menu provides measurement information.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASUREMENTS 3	04	00		
This column contains measurement parameters				
IA-2 Magnitude	04	01		Not Settable
IA-2 Magnitude measurement (P343/P344/P345)				
IA-2 Phase Angle	04	02		Not Settable
IA-2 Phase Angle measurement (P343/P344/P345)				
IB-2 Magnitude	04	03		Not Settable
IB-2 Magnitude measurement (P343/P344/P345)				
IB-2 Phase Angle	04	04		Not Settable
IB-2 Phase Angle measurement (P343/P344/P345)				
IC-2 Magnitude	04	05		Not Settable
IC-2 Magnitude measurement (P343/P344/P345)				
IC-2 Phase Angle	04	06		Not Settable
IC-2 Phase Angle measurement (P343/P344/P345)				
IA Differential	04	07		Not Settable
IA Differential measurement (P343/P344/P345)				
IB Differential	04	08		Not Settable
IB Differential measurement (P343/P344/P345)				
IC Differential	04	09		Not Settable
IC Differential measurement (P343/P344/P345)				
IA Bias	04	0A		Not Settable
IA Bias measurement (P343/P344/P345)				
IB Bias	04	0B		Not Settable
IB Bias measurement (P343/P344/P345)				
IC Bias	04	0C		Not Settable
IC Bias measurement (P343/P344/P345)				
IREF Diff	04	0D		Not Settable
IREF Diff measurement				
IREF Bias	04	0E		Not Settable
IREF Bias measurement				
VN 3rd Harmonic	04	0F		Not Settable
VN 3rd Harmonic measurement (P343/P344/P345)				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
NPS Thermal	04	10		Not Settable
NPS Thermal measurement				
Reset NPSThermal	04	11	No	No or Yes
Reset NPSThermal command.				
RTD 1	04	12		Not Settable
RTD 1 measurement				
RTD 2	04	13		Not Settable
RTD 2 measurement				
RTD 3	04	14		Not Settable
RTD 3 measurement				
RTD 4	04	15		Not Settable
RTD 4 measurement				
RTD 5	04	16		Not Settable
RTD 5 measurement				
RTD 6	04	17		Not Settable
RTD 6 measurement				
RTD 7	04	18		Not Settable
RTD 7 measurement				
RTD 8	04	19		Not Settable
RTD 8 measurement				
RTD 9	04	1A		Not Settable
RTD 9 measurement				
RTD 10	04	1B		Not Settable
RTD 10 measurement				
RTD Open Cct	04	1C		Not Settable
Displays the status of the ten RTDs as a binary string. 0 = No Open Circuit, 1 = Open Circuit. The Open Cct alarms are latched.				
RTD Short Cct	04	1D		Not Settable
Displays the status of the ten RTDs as a binary string. 0 = No Short Circuit, 1 = Short Circuit. The Short Cct alarms are latched.				
RTD Data Error	04	1E		Not Settable
Displays the status of the ten RTDs as a binary string. 0 = No Data Error, 1 = Data Error. The Data Error alarms are latched.				
Reset RTD Flags	04	1F	No	No or Yes
Reset RTD alarms command. Resets latched RTD Open Cct, Short Cct, Data Error alarms.				
APh Sen Watts	04	20		Not Settable
APh Sensitive Watts measurement				
APh Sen VArs	04	21		Not Settable
APh Sensitive VArs measurement				
APh Power Angle	04	22		Not Settable
APh Sensitive Power Angle measurement				
Thermal Overload	04	23		Not Settable
Thermal Overload measurement				
Reset ThermalO/L	04	24	No	No or Yes
Reset Thermal Overload command. Resets thermal state to 0.				
CLIO Input 1	04	25		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CLIO Input 1 measurement				
CLIO Input 2	04	26		Not Settable
CLIO Input 2 measurement				
CLIO Input 3	04	27		Not Settable
CLIO Input 3 measurement				
CLIO Input 4	04	28		Not Settable
CLIO Input 4 measurement				
F Band1 Time (s)	04	30		Not Settable
Turbine Abnormal Frequency (TAF). Band 1 Accumulated Time				
Reset Freq Band1	04	32	No	No or Yes
Reset TAF Band 1 Time				
F Band2 Time (s)	04	34		Not Settable
Turbine Abnormal Frequency (TAF). Band 2 Accumulated Time				
Reset Freq Band2	04	36	No	No or Yes
Reset TAF Band 2 Time				
F Band3 Time (s)	04	38		Not Settable
Turbine Abnormal Frequency (TAF). Band 3 Accumulated Time				
Reset Freq Band3	04	3A	No	No or Yes
Reset TAF Band 3 Time				
F Band4 Time (s)	04	3C		Not Settable
Turbine Abnormal Frequency (TAF). Band 4 Accumulated Time				
Reset Freq Band4	04	3E	No	No or Yes
Reset TAF Band 4 Time				
F Band5 Time (s)	04	40		Not Settable
Turbine Abnormal Frequency (TAF). Band 5 Accumulated Time				
Reset Freq Band5	04	42	No	No or Yes
Reset TAF Band 5 Time				
F Band6 Time (s)	04	44		Not Settable
Turbine Abnormal Frequency (TAF). Band 6 Accumulated Time				
Reset Freq Band6	04	46	No	No or Yes
Reset TAF Band 6 Time				
df/dt	04	48		Not Settable
dep on df/dt setting in configuration collumn				
Volts/Hz	04	50		Not Settable
Vab/Frequency				
64S V Magnitude	04	52		Not Settable
Low frequency injection St EF Voltage magnitude measured at the relay terminal (P345)				
64S I Magnitude	04	54		Not Settable
Low frequency injection St EF Current magnitude measured at the relay terminal (P345)				
64S I Angle	04	55		Not Settable
St EF current angle measurement, affected by Comp Angle setting when St EF is enabled. I64S phase angle relative to V64S vector. (P345)				
64S R secondary	04	57		Not Settable
St EF secondary resistance measurement at the relay terminal, affected by Series R and Parallel G settings (P345)				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
64S R primary	04	58		Not Settable
St EF primary resistance, converted from secondary resistance using the R Factor setting (P345)				
64R CL Input	04	71		Not Settable
64S R primary measurement				
64R R Fault	04	72		Not Settable
64R R Fault measurement				
IA Diff PU	04	91		Not Settable
IA Diff PU measurement (P343/P344/P345)				
IB Diff PU	04	92		Not Settable
IB Diff PU measurement (P343/P344/P345)				
IC Diff PU	04	93		Not Settable
IC Diff PU measurement (P343/P344/P345)				
IA Bias PU	04	94		Not Settable
IA Bias PU measurement (P343/P344/P345)				
IB Bias PU	04	95		Not Settable
IB Bias PU measurement (P343/P344/P345)				
IC Bias PU	04	96		Not Settable
IC Bias PU measurement (P343/P344/P345)				
IA Diff 2H	04	97		Not Settable
IA Diff 2H measurement (P343/P344/P345)				
IB Diff 2H	04	98		Not Settable
IB Diff 2H measurement (P343/P344/P345)				
IC Diff 2H	04	99		Not Settable
IC Diff 2H measurement (P343/P344/P345)				
IA Diff 5H	04	9A		Not Settable
IA Diff 5H measurement (P343/P344/P345)				
IB Diff 5H	04	9B		Not Settable
IB Diff 5H measurement (P343/P344/P345)				
IC Diff 5H	04	9C		Not Settable
IC Diff 5H measurement (P343/P344/P345)				
CT2 I1 Mag	04	9D		Not Settable
CT2 I1 Magnitude measurement (P343/P344/P345)				
CT2 I1 Ang	04	9E		Not Settable
CT2 I1 Phase Angle measurement (P343/P344/P345)				
CT2 I2 Mag	04	9F		Not Settable
CT2 I2 Magnitude measurement (P343/P344/P345)				
CT2 I2 Ang	04	A0		Not Settable
CT2 I2 Phase Angle measurement (P343/P344/P345)				
CT2 I0 Mag	04	A1		Not Settable
CT2 I0 Magnitude measurement (P343/P344/P345)				
CT2 I0 Ang	04	A2		Not Settable
CT2 I0 Phase Angle measurement (P343/P344/P345)				
CT1 I2/I1	04	A3		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CT1 I2/I1 measurement (P343/P344/P345)				
CT2 I2/I1	04	A4		Not Settable
CT2 I2/I1 measurement (P343/P344/P345)				

Table 37 - Measurement 3 menu

5.7 Measurements 4

This menu provides measurement information.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Hot Spot T	05	01		Not Settable
Hot Spot T measurement				
Top Oil T	05	02		Not Settable
Top Oil T measurement				
Reset Xthermal	05	03	No	No or Yes
Reset Thermal Overload command. Resets thermal state to 0.				
Ambient T	05	04		Not Settable
Ambient T measurement				
TOL Pretrip left	05	05		Not Settable
Thermal OverLoad pre-trip time left. TOL Pretrip left measurement				
LOL status	05	06		Not Settable
Accumulated Loss Of Life. Invisible only when the turbine abnormal frequency protection is not enabled.				
Reset LOL	05	07	No	No or Yes
Reset Loss Of Life (LOL) command. Resets state to 0.				
Rate of LOL	05	08		Not Settable
Rate of LOL (ROLOL) measurement				
LOL Ageing Fact	05	09		Not Settable
Aging Acceleration Factor (FAA). LOL Aging Factor measurement				
Lres at Design T	05	0A		Not Settable
Residual life hours at design temperature QH,r. Lres at designed measurement				
FAA,m	05	0B		Not Settable
Mean Aging Acceleration Factor (FAA,m). FAA,m measurement				
Lres at FAA,m	05	0C		Not Settable
Residual life hours at FAA,m (LRES(FAA,m)). Lres at FAA,m measurement				
Max Iac	05	20		Not Settable
Max Iac measurement				
DLR Ambient Temp	05	22		Not Settable
DLR Ambient Temp measurement				
Wind Velocity	05	24		Not Settable
Wind Velocity measurement				
Wind Direction	05	26		Not Settable
Wind Direction measurement				
Solar Radiation	05	28		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Solar Radiation measurement				
Effct wind angle	05	32		Not Settable
Effct wind angle measurement				
Pc	05	34		Not Settable
Pc measurement				
Pc, natural	05	36		Not Settable
Pc, natural measurement				
Pc1, forced	05	38		Not Settable
Pc1, forced measurement				
Pc2, forced	05	3A		Not Settable
Pc2, forced measurement				
DLR Ampacity	05	3C		Not Settable
DLR Ampacity measurement				
DLR CurrentRatio	05	3E		Not Settable
DLR CurrentRatio measurement				
Dyn Conduct Temp	05	40		Not Settable
Dyn Conduct Temp measurement				
Steady Conduct T	05	42		Not Settable
Steady Conduct T measurement				
Time Constant	05	44		Not Settable
Time Constant measurement				

Table 38 - Measurement 4 menu

5.8 Circuit Breaker Condition

The relay includes measurements to monitor the CB condition.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CB Operations	06	01		Not Settable
Number of Circuit Breaker Operations				
Total IA Broken	06	02		Not Settable
Broken Current A Phase				
Total IB Broken	06	03		Not Settable
Broken Current B Phase				
Total IC Broken	06	04		Not Settable
Broken Current C Phase				
CB Operate Time	06	05		Not Settable
Circuit Breaker operating time				
CB Close Time	06	06		Not Settable
Circuit Breaker close time				
Reset CB Data	06	07	No	No or Yes
Reset All Circuit Breaker Values				

Table 39 - Circuit breaker condition menu

5.9 Circuit Breaker Control

The relay includes settings to reset CB condition monitoring lockout alarms and set the type of CB auxiliary contacts that will be used to indicate the CB position.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CB CONTROL	07	00		
This column contains circuit breaker settings				
CB Control by	07	01	Disabled	Disabled, Local, Remote, Local + Remote, Opto, Opto + Local, Opto + Remote, Opto + Remote + Local
Selects the type of circuit breaker control to be used				
Close Pulse Time	07	02	500 ms	0.1s to 10s step 0.01s
Set period during which the CB should close when a CB close command is issued.				
Trip Pulse Time	07	03	500 ms	0.1s to 5s step 0.01s
Set period during which the CB should trip when a CB trip command is issued.				
Man Close Delay	07	05	10 s	0.01s to 600s step 0.01s
Set delay after operator controlled CB close sequence is initiated, before a CB close output can be issued. (Allows operator to retire to a place of safety before the CB close command is issued).				
CB Healthy Time	07	06	5 s	0.01s to 9999s step 0.01s
Maximum waiting time for input DDB: CB1 Healthy (= gas pressure OK, spring charged etc) to enable CB1 Close by manual control. Same setting applies to DDB: CB2 Healthy to enable CB2 Close by manual control. If set time runs out with input DDB: CBx Healthy low (= 0), alarm Control CBx Unhealthy is set and CB close sequence is cancelled.				
Sys Check Time	07	07	5 s	0.01s to 9999s step 0.01s
Maximum waiting time for input signal CB1MSCOK from system check logic, to enable CB1 Close by manual control. Same setting applies to input signal CB2MSCOK to enable CB2 Close by manual control. If set time runs out with input signal CBxMSCOK low (= 0), alarm Control CBx NoChSync is set and CB close sequence is cancelled.				
Lockout Reset	07	08	No	0 = No, 1 = Yes
Command to reset the Lockout Alarm				
Reset Lockout by	07	09	CB Close	0 = User Interface, 1 = 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	07	0A	1 s	0.01 to 600 step 0.01
If Reset Lockout by is set to CB close then Man Close RstDly timer allows reset of Lockout state after set time delay				
CB Status Input	07	11	None	0 = None, 1 = 52A, 2 = 52B, 3 = Both 52A and 52B
Setting to define the type of circuit breaker contacts that will be used for the circuit breaker control logic. Form A contacts match the status of the circuit breaker primary contacts, form B are opposite to the breaker status. When 1 pole is selected, individual contacts must be assigned in the Programmable Scheme Logic for phase A, phase B, and phase C. Setting 3 pole means that only a single contact is used, common to all 3 poles.				

Table 40 - Circuit breaker condition menu

5.10 Date and Time

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

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DATE AND TIME	08	00		
This column contains Date and Time settings				
Date/Time	08	01		
Displays the relay's current date and time.				
Date 12/01/1998	08	02		<Date>
Displays the date. Front Panel Menu only				
Time 12:00:00	08	03		<Time>
Displays the time. Front Panel Menu only				
IRIG-B Sync	08	04	Disabled	Enabled, Disabled
Enable IRIG-B time synchronization.				
IRIG-B Status	08	05		Not Settable
Displays the status of IRIG-B: Card Not Fitted, Card Failed, Signal Healthy or No Signal				
Battery Status	08	06		Not Settable
Displays whether the battery is Healthy or Dead				
Battery Alarm	08	07	Enabled	Enabled, Disabled
Setting that determines whether an unhealthy relay battery condition is alarmed or not				
SNTP Status	08	13		Not Settable
Ethernet versions only. Displays information about the SNTP time synchronization status: Disabled, Trying Server 1, Trying Server 2, Server 1 OK, Server 2 OK, No response or No valid clock.				
LocalTime Enable	08	20	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	08	21	0 mins	-720 mins to 720 mins step 15 mins
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	08	22	Disabled	Enabled, Disabled
Setting to turn on/off daylight saving time adjustment to local time.				
DST Offset	08	23	60 mins	30 mins, 60 mins
Setting to specify daylight saving offset which will be used for the time adjustment to local time.				
DST Start	08	24	Last	First, Second, Third, Fourth, Last
Setting to specify the week of the month in which daylight saving time adjustment starts				
DST Start Day	08	25	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	08	26	March	Any of the 12 months
Setting to specify the month in which daylight saving time adjustment starts				
DST Start Mins	08	27	60 mins	0 mins to 1425 mins step 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	08	28	Last	First, Second, Third, Fourth, Last
Setting to specify the week of the month in which daylight saving time adjustment ends				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DST End Day	08	29	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	08	2A	October	Any of the 12 months
Setting to specify the month in which daylight saving time adjustment ends				
DST End Mins	08	2B	60 mins	0 mins to 1425 mins step 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	08	30	Local	UTC, 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	08	31	Local	UTC, Local
Setting for the rear port 2 interface to specify if time synchronization received will be local or universal time co-ordinated				
DNPOE Time Zone	08	32	Local	UTC, Local
DNP3.0 over Ethernet versions only. Setting to specify if time synchronisation received will be local or universal time co-ordinate.				
Tunnel Time Zone	08	33	Local	UTC, Local
Ethernet versions only for tunnelled courier. Setting to specify if time synchronization received will be local or universal time co-ordinate				

Table 41 - Date and time menu

5.11 CT and VT Ratios

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CT AND VT RATIOS	0A	00		
This column contains settings for Current and Voltage Transformer ratios				
Main VT Primary	0A	12	110*V1	From 100 V to 1MV step 1 V
Sets the main voltage transformer input primary voltage. V1=1 for Vn=100-120, V1=4 for Vn=380-440.				
Main VT Sec'y	0A	13	110*V1	From 80*V1 to 140*V1 step 1*V1
Sets the main voltage transformer input secondary voltage.				
C/S VT Primary	0A	16	110*V1	From 100 V to 1MV step 1 V
Sets the check sync. voltage transformer input primary voltage. (P345)				
C/S VT Sec'y	0A	17	110*V1	From 80*V1 to 140*V1 step 1*V1
Sets the check sync. voltage transformer input secondary voltage. (P345)				
VN VT Primary VN1 VT Primary	0A	22	110*V1	From 100 V to 1MV step 1 V
Sets the Neutral Displacement VT Primary voltage. VN VT Primary is used on P342/P343 while VN1 VT Primary applies to P344/P345. Also used for check synch. on P342 + P343				
VN VT Secondary VN1 VT Secondary	0A	23	110*V1	From 80*V1 to 140*V1 step 1*V1
Sets the Neutral Displacement VT Secondary voltage. VN VT Secondary is used on P342/P343 while VN1 VT Secondary applies to P344/P345. Also used for check synch. on P342 + P343				
VN2 VT Primary	0A	27	110*V1	From 100 V to 1MV step 1 V
Sets the Second NVD VT Primary voltage. Also used for check synch. on P344. (P344/P345)				
VN2 VT Secondary	0A	28	110*V1	From 80*V1 to 140*V1 step 1*V1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Sets the Second NVD VT Secondary voltage. Also used for check synch. on P344. (P344/P345)				
Ph CT Polarity Ph CT1 Polarity	0A	31	Standard	Standard, Inverted
Polarity of phase CT group (3 phase). Ph CT Polarity is used on P342 while Ph CT1 Polarity applies to P343/P344/P345.				
Phase CT Primary Phase CT1 Prim'y	0A	32	300A	From 1A to 60kA step 1A
Sets the phase CT1 current transformer input primary current rating. Phase CT Primary is used on P342 while Phase CT1 Prim'y applies to P343/P344/P345. In=Phase CT secondary rating				
Phase CT Sec'y Phase CT1 Sec'y	0A	33	1A	From 1A to 5A step 4A
Sets the phase CT1 current transformer input secondary current rating. Phase CT Sec'y is used on P342 while Phase CT1 Sec'y applies to P343/P344/P345.				
Ph CT2 Polarity	0A	36	Standard	Standard, Inverted
Polarity of phase CT2 group (3 phase) (P343/P344/P345)				
Phase CT2 Prim'y	0A	37	300A	From 1A to 60kA step 1A
Sets the phase CT2 current transformer input primary current rating (P343/P344/P345). I4=Phase CT2 secondary rating				
Phase CT2 Sec'y	0A	38	1A	From 1A to 5A step 4A
Sets the CT2 phase current transformer input secondary current rating (P343/P344/P345).				
E/F CT Polarity	0A	51	Standard	Standard, Inverted
Polarity of E/F (IN1) CT				
E/F CT Primary	0A	52	1A	From 1A to 60kA step 1A
Sets the earth fault current transformer input primary current rating. I2=E/F CT secondary rating				
E/F CT Secondary	0A	53	1A	From 1A to 5A step 4A
Sets the earth fault current transformer input secondary current rating.				
Isen CT Polarity	0A	61	Standard	Standard, Inverted
Polarity of SEF (Isen) CT				
Isen CT Primary	0A	62	1A	From 1A to 60kA step 1A
Sets the sensitive current transformer input primary current rating. I3=SEF CT secondary rating				
Isen CT Sec'y	0A	63	1A	From 1A to 5A step 4A
Sets the sensitive current transformer input secondary current rating.				

Table 42 - CT and VT ratio settings

5.12 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:

Courier Text	Col	Row	Default Setting	Available Setting
Description				
RECORD CONTROL	0B	00		
This column contains settings for Record Controls				
Alarm Event	0B	04	Enabled	Enabled, disabled
Disabling this setting means that no event is generated for alarms				
Relay O/P Event	0B	05	Enabled	Enabled, disabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Disabling this setting means that no event will be generated for any change in logic output state.				
Opto Input Event	0B	06	Enabled	Enabled, disabled
Disabling this setting means that no event will be generated for any change in logic input state.				
General Event	0B	07	Enabled	Enabled, disabled
Disabling this setting means that no General Events are generated				
Fault Rec Event	0B	08	Enabled	Enabled, disabled
Disabling this setting means that no event will be generated for any fault that produces a fault record				
Maint Rec Event	0B	09	Enabled	Enabled, disabled
Disabling this setting means that no event will be generated for any occurrence that produces a maintenance record.				
Protection Event	0B	0A	Enabled	Enabled, disabled
Disabling this setting means that any operation of protection elements will not be logged as an event				
Clear Dist Recs	0B	30	No	0 = No, 1 = Yes
Selecting "Yes" will cause the existing disturbance records to be cleared and an event will be generated indicating that the disturbance records have been erased.				
Security Event	0B	31	Enabled	Enabled, disabled
Disabling this setting means that any operation of security elements will not be logged as an event				
DDB 31 - 0	0B	40	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 63 - 32	0B	41	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 95 - 64	0B	42	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 127 - 96	0B	43	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 159 - 128	0B	44	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 191 - 160	0B	45	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 223 - 192	0B	46	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 255 - 224	0B	47	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DDB 287 - 256	0B	48	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 319 - 288	0B	49	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 351 - 320	0B	4A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 383 - 352	0B	4B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 415 - 384	0B	4C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 447 - 416	0B	4D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 479 - 448	0B	4E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 511 - 480	0B	4F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 543 - 512	0B	50	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 575 - 544	0B	51	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 607 - 576	0B	52	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 639 - 608	0B	53	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 671 - 640	0B	54	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Chooses whether any individual DDB's 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 703 - 672	0B	55	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 735 - 704	0B	56	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 767 - 736	0B	57	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 799 - 768	0B	58	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 831 - 800	0B	59	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 863 - 832	0B	5A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 895 - 864	0B	5B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 927 - 896	0B	5C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 959 - 928	0B	5D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 991 - 960	0B	5E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1023 - 992	0B	5F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1055 - 1024	0B	60	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DDB 1087 - 1056	0B	61	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1119 - 1088	0B	62	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1151 - 1120	0B	63	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1183 - 1152	0B	64	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1215 - 1184	0B	65	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1247 - 1216	0B	66	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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	0B	67	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1311 - 1280	0B	68	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1343 - 1312	0B	69	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1375 - 1344	0B	6A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1407 - 1376	0B	6B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1439 - 1408	0B	6C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1471 - 1440	0B	6D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Chooses whether any individual DDB's 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 1503 - 1472	0B	6E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1535 - 1504	0B	6F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1567 - 1536	0B	70	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1599 - 1568	0B	71	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1631 - 1600	0B	72	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1663 - 1632	0B	73	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1695 - 1664	0B	74	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1727 - 1696	0B	75	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1759 - 1728	0B	76	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1791 - 1760	0B	77	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1823 - 1792	0B	78	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1855 - 1824	0B	79	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DDB 1887 - 1856	0B	7A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1919 - 1888	0B	7B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1951 - 1920	0B	7C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1983 - 1952	0B	7D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 2015 - 1984	0B	7E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 2047 - 2016	0B	7F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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.				

Table 43 - Record control menu

5.13 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”.

The integral disturbance recorder has an area of memory specifically set aside for record storage. The number of records that may be stored depends upon the selected recording duration but the relays can typically store at least 20 records, each of 10.5 s duration.

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 which are taken at a rate of 24 samples per cycle.

Each disturbance record consists of 9-15 analogue data channels (depending on model) and 32 digital data channels. Note that the relevant CT and VT ratios for the analogue channels are also extracted to enable scaling to primary quantities).

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DISTURB RECORDER	0C	00		
This column contains settings for the Disturbance Recorder				
Duration	0C	52	1.5 s	0.1s to 10.5s step 0.01s
This sets the overall recording time.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Trigger Position	0C	54	0.333	From 0% to 100% step 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 1.5 s with the trigger point being at 33.3% of this, giving 0.5 s pre-fault and 1s post fault recording times.				
Trigger Mode	0C	56	Single	Single, 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	0C	58	VAN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 2	0C	59	VBN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 3	0C	5A	VCN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 4	0C	5B	VN1	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 5	0C	5C	IA (IA-1)	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 6	0C	5D	IB (IB-1)	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 7	0C	5E	IC (IC-1)	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 8	0C	5F	I Sensitive	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 9	0C	60	IN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
AnalogChannel 10	0C	61	IA-2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel (P343/P344/P345).				
AnalogChannel 11	0C	62	IB-2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel (P343/P344/P345).				
AnalogChannel 12	0C	63	IC-2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel (P343/P344/P345).				
AnalogChannel 13	0C	64	VN2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel. (P344/P345)				
AnalogChannel 14	0C	65	V64S	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel (P345).				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
AnalogChannel 15	0C	66	I64S	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel (P345).				
Digital Input 1	0C	80	Output R1	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 1 Trigger	0C	81	No Trigger	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 Input 2	0C	82	Output R2	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 2 Trigger	0C	83	No Trigger	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 Input 3	0C	84	Output R3	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 3 Trigger	0C	85	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 Input 4	0C	86	Output R4	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 4 Trigger	0C	87	No Trigger	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 Input 5	0C	88	Output R5	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 5 Trigger	0C	89	No Trigger	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 Input 6	0C	8A	Output R6	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 6 Trigger	0C	8B	No Trigger	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 Input 7	0C	8C	Output R7	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 7 Trigger	0C	8D	No Trigger	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 Input 8	0C	8E	Input L1 (P342) Output R8 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals

Courier Text	Col	Row	Default Setting	Available Setting
Description				
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 8 Trigger	0C	8F	No Trigger	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 Input 9	0C	90	Input L2 (P342) Output R9 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 9 Trigger	0C	91	No Trigger	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 Input 10	0C	92	Input L3 (P342) Output R10 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 10 Trigger	0C	93	No Trigger	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 Input 11	0C	94	Input L4 (P342) Output R11 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 11 Trigger	0C	95	No Trigger	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 Input 12	0C	96	Input L5 (P342) Output R12 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 12 Trigger	0C	97	No Trigger	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 Input 13	0C	98	Input L6 (P342) Output R13 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 13 Trigger	0C	99	No Trigger	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 Input 14	0C	9A	Input L7 (P342) Output R14 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 14 Trigger	0C	9B	No Trigger	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 Input 15	0C	9C	Input L8 (P342) Input L1 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 15 Trigger	0C	9D	No Trigger	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 Input 16	0C	9E	Unused (P342) Input L2 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals

Courier Text	Col	Row	Default Setting	Available Setting
Description				
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 16 Trigger	0C	9F	No Trigger	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 Input 17	0C	A0	Unused (P342) Input L3 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 17 Trigger	0C	A1	No Trigger	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 Input 18	0C	A2	Unused (P342) Input L4 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 18 Trigger	0C	A3	No Trigger	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 Input 19	0C	A4	Unused (P342) Input L5 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 19 Trigger	0C	A5	No Trigger	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 Input 20	0C	A6	Unused (P342) Input L6 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 20 Trigger	0C	A7	No Trigger	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 Input 21	0C	A8	Unused (P342) Input L7 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 21 Trigger	0C	A9	No Trigger	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 Input 22	0C	AA	Unused (P342) Input L8 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 22 Trigger	0C	AB	No Trigger	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 Input 23	0C	AC	Unused (P342) Input L9 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 23 Trigger	0C	AD	No Trigger	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 Input 24	0C	AE	Unused (P342) Input L10 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals

Courier Text	Col	Row	Default Setting	Available Setting
Description				
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 24 Trigger	0C	AF	No Trigger	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 Input 25	0C	B0	Unused (P342) Input L11 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 25 Trigger	0C	B1	No Trigger	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 Input 26	0C	B2	Unused (P342) Input L12 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 26 Trigger	0C	B3	No Trigger	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 Input 27	0C	B4	Unused (P342) Input L13 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 27 Trigger	0C	B5	No Trigger	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 Input 28	0C	B6	Unused (P342) Input L14 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 28 Trigger	0C	B7	No Trigger	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 Input 29	0C	B8	Unused (P342) Input L15 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 29 Trigger	0C	B9	No Trigger	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 Input 30	0C	BA	Unused (P342) Input L16 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 30 Trigger	0C	BB	No Trigger	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 Input 31	0C	BC	Unused (P342) Function Key 10 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 31 Trigger	0C	BD	No Trigger (P342) Trigger L/H (P343 P344 P345)	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.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Digital Input 32	0C	BE	Unused	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 32 Trigger	0C	BF	No Trigger	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.				

Table 44 - Disturbance record settings

Note	*The available analogue and digital signals differ between relay types and models.*

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 1.5s with the trigger point being at 33.3% of this, giving 0.5s pre-fault and 1s post fault recording times.

If a further trigger occurs whilst a recording is taking place, the recorder will ignore the trigger if the ‘Trigger Mode’ has been set to ‘Single’. However, if this has been set to ‘Extended’, the post trigger timer will be reset to zero, thereby extending the recording time.

As can be seen from the menu, each of the analogue channels is selectable from the available analogue inputs to the relay. 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. The complete list of these signals may be found by viewing the available settings in the relay menu or via 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, via the ‘Input Trigger’ cell. The default trigger settings are that any dedicated trip output contacts (e.g. relay 3) will trigger the recorder.

5.14 Measurements Setup

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASURE'T SETUP	0D	00		
This column contains settings for the measurement setup				
Default Display	0D	01	User Banner	Not Settable
This displays the default display which is possible to change whilst at the default level using the arrow keys. Only visible on UI.				
Local Values	0D	02	Primary	Primary, Secondary
Local Measurement Values.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	0D	03	Primary	Primary, Secondary
Remote Measurement Values.This setting controls whether measured values via the rear communication port are displayed as primary or secondary quantities.				
Measurement Ref	0D	04	VA	0 = VA, 1 = VB, 2 = VC, 3 = IA, 4 = IB, 5 = IC
Using this setting the phase reference for all angular measurements by the IED can be selected. This reference is for Measurements 1. Measurements 3 uses always IA local as a reference				
Measurement Mode	0D	05	0	0, 1, 2, 3
Measurement Mode				
Fix Dem Period	0D	06	15 mins	1 mins to 99 mins step 1 mins

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Fixed Demand Interval				
Roll Sub Period	0D	07	1 mins	1 mins to 99 mins step 1 mins
Rolling demand sub period				
Num Sub Periods	0D	08	15	1 to 15 step 1
Number of rolling sub-periods				
Remote 2 Values	0D	0B	Primary	Primary, Secondary
The setting defines whether the values measured via the Second Rear Communication port are displayed in primary or secondary terms.				

Table 45 - Measurement setup settings

5.15 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 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

Courier Text	Col	Row	Default Setting	Available Setting
Description				
COMMUNICATIONS	0E	00		
This column contains general communications settings				
RP1 Protocol	0E	01		Not Settable
Indicates the communications protocol that will be used on the rear communications port.				
RP1 Address	0E	02	255	0 to 255 (Courier)
Sets the relay address (protocol dependent). Build = Courier,Rear Port 1 Courier Protocol device address				
RP1 Address	0E	02	1	1 to 247 (Modbus)
Sets the relay address (protocol dependent). Build = Modbus Default Modbus address is 1,Rear Port 1 Modbus Protocol device address				
RP1 Address	0E	02	1	0 to 254 (IEC60870)
Sets the relay address (protocol dependent). Build = IEC60870-5-103,Rear Port 1 IEC60870-5-103 Protocol device address				
RP1 Address	0E	02	1	0 to 65519 (DNP3.0)
Sets the relay address (protocol dependent). Build=DNP 3.0,Rear Port 1 DNP 3.0 Protocol device address				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
RP1 InactivTimer	0E	03	15 mins	1 mins to 30 mins step 1 mins (Courier)
Defines the period of inactivity before relay reverts to its default state. Build = Courier,Rear Port 1 Courier Protocol inactivity timer				
RP1 InactivTimer	0E	03	15 mins	1 mins to 30 mins step 1 mins (Modbus)
Defines the period of inactivity before relay reverts to its default state. Build = Modbus,Rear Port 1 Modbus Protocol inactivity timer				
RP1 InactivTimer	0E	03	15 mins	1 mins to 30 mins step 1 mins (IEC60870)
Defines the period of inactivity before relay reverts to its default state. Build = IEC60870-5-103,Rear Port 1 IEC60870-5-103 Protocol inactivity timer				
RP1 Baud Rate	0E	04	19200 bits/s	9600, 19200, 38400 (Modbus)
Defines the Baud rate for RP1. Build = Modbus,Rear Port 1 Modbus Protcol serial bit/baud rate				
RP1 Baud Rate	0E	04	19200 bits/s	9600, 19200 (IEC60870)
Defines the Baud rate for RP1. Build = IEC60870-5-103,Rear Port 1 IEC60870-5-103 Protcol serial bit/baud rate				
RP1 Baud Rate	0E	04	19200 bits/s	1200, 2400, 4800, 9600, 19200, 38400 (DNP3.0)
Defines the Baud rate for RP1. Build = DNP 3.0,Rear Port 1 DNP 3.0 Protcol serial bit/baud rate				
RP1 Parity	0E	05	None	Odd, Even, None (Modbus)
This cell controls the parity format used in the data frames. It is important that both IED and master station are set with the same parity setting. Build = Modbus,Rear Port 1 Modbus Protocol parity				
RP1 Parity	0E	05	None	Odd, Even, None (DNP3.0)
This cell controls the parity format used in the data frames. It is important that both IED and master station are set with the same parity setting. Build = DNP 3.0,Rear Port 1 DNP 3.0 Protocol parity				
RP1 Meas Period	0E	06	15 s	1s to 60s step 1s (IEC60870)
Defines the measurement period for the cyclic measurements. Build = IEC60870-5-103,Rear Port 1 IEC60870-5-103 Protocol measurement period				
RP1 PhysicalLink	0E	07	Copper	Copper, fiber Optic, Kbus
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 is required. Visible if Fibre Optic Communications card specified by model number),Rear Port 1 Physical link selector, Available when Fibre Optic Comms card is specified by model number				
DNP Time Sync	0E	08	Disabled	Enabled, Disabled (DNP3.0)
If set to Enabled the 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. Build=DNP 3.0 Visible when IRIG-B is disabled,Rear Port 1 DNP 3.0 Protocol time sync configuration NB Not available when IRIG-B option fitted and enabled				
Modbus IEC Time	0E	09	Standard	Standard, Reverse (Modbus)
When Standard is selected, the time format complies with IEC60870-5-4 requirements so 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. Build = Modbus,Controls the format of the time-date G12 data type. Modbus Only				
RP1 CS103Blcking	0E	0A	Disabled	Disabled, Monitor blocking, Command Blocking (IEC60870)
Sets the blocking type*. Build=IEC60870-5-103,Rear Port 1 IEC60870-5-103 Protocol blocking configuration				
RP1 Card Status	0E	0B		Not Settable
Displays the status of the card in RP1. Build = Courier,Rear Port 1 Courier Protocol Status				
RP1 Port Config	0E	0C	K-Bus	Kbus, EIA485 (Courier)

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Defines communications configuration type for RP1. Build = Courier,Rear Port 1 Courier Protocol copper port configuration; K-Bus or EIA485				
RP1 Comms Mode	0E	0D	IEC60870 FT1.2	IEC60870 FT1.2 Frame, 10-bit No parity
Defines communications mode for RP1. Build = Courier,Rear Port 1 Courier Protocol EIA485 mode				
RP1 Baud Rate	0E	0E	19200 bits/s	9600 bps, 19200 bps, 38400 bps (Courier)
Defines the Baud rate for RP1. Build = Courier,Rear Port 1 Courier Protocol EIA485 bit/baud rate				
Meas Scaling	0E	0F	Normalised	0 = Normalised, 1 = Primary, 2 = Secondary
DNP 3.0 and IEC61850+DNP3oE only. Setting to report analogue values in terms of primary, secondary or normalized (with respect to the CT/VT ratio setting) values.				
Message Gap (ms)	0E	10	0	From 0 to 50 step 1
DNP 3.0 and IEC61850+DNP3oE only. Setting to report analogue values in terms of primary, secondary or normalized (with respect to the CT/VT ratio setting) values.				
DNP Need Time	0E	11	10 mins	1 mins to 30 mins step 1 mins (DNP3.0)
The duration of time to wait before requesting another time sync from the master				
DNP App Fragment	0E	12	2048	100 to 2048 step 1 (DNP3.0)
The maximum message length (application fragment size) transmitted by the relay				
DNP App Timeout	0E	13	2 s	1s to 120 s step 1s (DNP3.0)
Duration of time to wait, after sending a message fragment and awaiting a confirmation from the master				
DNP SBO Timeout	0E	14	10 s	1s to 10 s step 1s (DNP3.0)
Duration of time to wait, after receiving a select command and awaiting an operate confirmation from the master				
DNP Link Timeout	0E	15	0 s	0s to 120s step 1s (DNP3.0)
Duration of time that the unit will wait for a Data Link Confirmation from the master				
ETH Protocol	0E	1F		Not Settable
Visible when Ethernet card fitted. Indicates the protocol used on the Network Interface Card: IEC61850 or IEC61850+DNP3				
MAC Addr 1	0E	22	Ethernet MAC Addr	MAC address (Ethernet)
Shows the MAC address of the 1st Ethernet port. Visible when Ethernet card fitted.				
MAC Addr 2	0E	23	Ethernet MAC Addr	MAC address (Ethernet)
Shows the MAC address of the 2nd Ethernet port. Visible when redundant Ethernet card fitted.				
ETH Tunl Timeout	0E	64	5 mins	1 mins to 30 mins step 1 mins (Ethernet)
Duration of time to wait before an inactive tunnel to MiCOM S1 Studio is reset. Visible when Ethernet card fitted.				
Redundancy Conf	0E	70		
NIOS PARAMETERS				
MAC Address	0E	71	NIOS MAC Addr	MAC address (Ethernet)
MAC address for the NIOS. The redundant agency device configuration is used for SNMP server. The MAC address is MAC2+1. This does not affect IEC61850 communications. Visible when redundant Ethernet card fitted and Comm Mode=PRP or HSR				
IP Address	0E	72	000.000.000.000	32 to 234 step 1
The redundant agency device configuration is used for SNMP server. This does not affect IEC61850 communications. Visible when redundant Ethernet card fitted and Comm Mode=PRP or HSR.				
Subnet mask	0E	73	000.000.000.000	32 to 234 step 1
Subnet Mask for the NIOS. The redundant agency device configuration is used for SNMP server. This does not affect IEC61850 communications. Visible when redundant Ethernet card fitted and Comm Mode=PRP or HSR				
Gateway	0E	74	000.000.000.000	32 to 234 step 1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Gateway for the NIOS. The redundant agency device configuration is used for SNMP server. This does not affect IEC61850 communications. Visible when redundant Ethernet card fitted and Comm Mode=PRP or HSR				
REAR PORT2 (RP2)	0E	80		
REAR PORT2 (RP2). Visible when Model no. Hardware option (Field 7) = 7 or 8,Visible when Rear Port 2 fitted.				
RP2 Protocol	0E	81		<Protocol>
Indicates the communications protocol used on the rear communications port RP2. Visible when Model no. Hardware option (Field 7) = 7 or 8 Implemented as datatype G71,Rear Port 2 Protocol - "Courier"				
RP2 Card Status	0E	84		Not Settable
Displays the status of the card in RP2. Visible when Model no. Hardware option (Field 7) = 7 or 8,Rear Port 2 Courier Protocol Status				
RP2 Port Config	0E	88	EIA232 (RS232)	EIA232, EIA485, Kbus
Defines communications configuration type for RP2. Visible if RP2 Card status = OK,Rear Port 2 Courier Protocol port configuration; K-Bus or EIA485				
RP2 Comms Mode	0E	8A	IEC60870 FT1.2	IEC60870 FT1.2 Frame, 10-bit No parity
Defines communications mode for RP2. Visible if RP2 Card status = OK and 0E88<2,Rear Port 2 Courier Protocol EIA485 mode				
RP2 Address	0E	90	255	0 to 255
Sets the relay address (protocol dependent). Visible if RP2 Card status = OK,Rear Port 2 Courier Protocol device address				
RP2 InactivTimer	0E	92	15 mins	1 mins to 30 mins step 1 mins
Defines the period of inactivity before relay reverts to its default state. Visible if RP2 Card status = OK,Rear Port 2 Courier Protocol inactivity timer				
RP2 Baud Rate	0E	94	19200 bits/s	9600 bps, 19200 bps, 38400 bps
Defines the Baud rate for RP2. Visible if RP2 Card status = OK and 0E88<2,Rear Port 2 Courier Protocol EIA485 bit/baud rate				

Table 46 - Communication settings

5.16 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".

Courier Text	Col	Row	Default Setting	Available Setting
Description				
COMMISSION TESTS	0F	00		
This column contains commissioning test settings				
Opto I/P Status	0F	01		16-bit binary string
This menu cell displays the status of the available IED'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	0F	02		16-bit binary string

Courier Text	Col	Row	Default Setting	Available Setting
Description				
This menu cell displays the status of the digital data bus (DDB) signals that result in energization of the available 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	0F	03		8-bit binary string
This menu cell displays the status of the eight digital data bus (DDB) signals that have been allocated in the 'Monitor Bit' cells.				
LED Status	0F	04		8-bit binary string
8-bit binary string that indicates which of the LEDs are ON (P342)				
Monitor Bit 1	0F	05	64	0 to 2047
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 2	0F	06	65	0 to 2047
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 3	0F	07	66	0 to 2047
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 4	0F	08	67	0 to 2047
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 5	0F	09	68	0 to 2047
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 6	0F	0A	69	0 to 2047
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 7	0F	0B	70	0 to 2047
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	0F	0C	71	0 to 2047
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	0F	0D	Disabled	Disabled, Test Mode, Contacts Blocked
Selecting 'Test Mode' blocks operation of maintenance counters. It also causes an alarm condition to be recorded and the yellow 'Out of Service' LED to illuminate and an alarm message 'Test Mode Alm' is given. This also freezes any information stored in the Circuit Breaker Condition column and in IEC 60870-5-103 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. It also causes an alarm condition to be recorded and the yellow 'Out of Service' LED to illuminate and an alarm message 'Contacts Blk Alm' is given. Once testing is complete the cell must be set back to 'Disabled' to restore the relay back to service. In IEC61850 models using edition 2 mode selecting Test Mode or Contacts Blocked will change the behaviour of all active logical nodes to test. The quality of all data will indicate also indicate test.				
Test Pattern	0F	0E	00000000000000000000000000000000(bin)	32 bit binary string
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	0F	0F	No Operation	No Operation, Apply Test, Remove Test

Courier Text	Col	Row	Default Setting	Available Setting
Description				
When the 'Apply Test' command in this cell is issued the contacts set for operation (set to '1') in the 'Test Pattern' cell are energised. 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 'Contacts Blocked' 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 physically monitor the state of each contact in turn.				
Test LEDs	0F	10	No Operation	No Operation, Apply Test
When the 'Apply Test' command in this cell is issued, the user-programmable LEDs will illuminate for approximately 2 seconds before they extinguish and the command text on the LCD reverts to 'No Operation'.				
Red LED Status	0F	15		Not Settable
This cell is an eighteen bit binary string that indicates which of the user-programmable LEDs on the IED are illuminated with the Red LED input active when accessing the IED from a remote location, a '1' indicating a particular LED is lit and a '0' not lit (P343/P344/P345).				
Green LED Status	0F	16		Not Settable
This cell is an eighteen bit binary string that indicates which of the user-programmable LEDs on the IED are illuminated with the Green LED input active when accessing the IED from a remote location, a '1' indicating a particular LED is lit and a '0' not lit (P343/P344/P345).				
DDB 31 - 0	0F	20		32-bit binary string
Displays the status of DDB signals				
DDB 63 - 32	0F	21		32-bit binary string
Displays the status of DDB signals				
DDB 95 - 64	0F	22		32-bit binary string
Displays the status of DDB signals				
DDB 127 - 96	0F	23		32-bit binary string
Displays the status of DDB signals				
DDB 159 - 128	0F	24		32-bit binary string
Displays the status of DDB signals				
DDB 191 - 160	0F	25		32-bit binary string
Displays the status of DDB signals				
DDB 223 - 192	0F	26		32-bit binary string
Displays the status of DDB signals				
DDB 255 - 224	0F	27		32-bit binary string
Displays the status of DDB signals				
DDB 287 - 256	0F	28		32-bit binary string
Displays the status of DDB signals				
DDB 319 - 288	0F	29		32-bit binary string
Displays the status of DDB signals				
DDB 351 - 320	0F	2A		32-bit binary string
Displays the status of DDB signals				
DDB 383 - 352	0F	2B		32-bit binary string
Displays the status of DDB signals				
DDB 415 - 384	0F	2C		32-bit binary string
Displays the status of DDB signals				
DDB 447 - 416	0F	2D		32-bit binary string
Displays the status of DDB signals				
DDB 479 - 448	0F	2E		32-bit binary string

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Displays the status of DDB signals				
DDB 511 - 480	0F	2F		32-bit binary string
Displays the status of DDB signals				
DDB 543 - 512	0F	30		32-bit binary string
Displays the status of DDB signals				
DDB 575 - 544	0F	31		32-bit binary string
Displays the status of DDB signals				
DDB 607 - 576	0F	32		32-bit binary string
Displays the status of DDB signals				
DDB 639 - 608	0F	33		32-bit binary string
Displays the status of DDB signals				
DDB 671 - 640	0F	34		32-bit binary string
Displays the status of DDB signals				
DDB 703 - 672	0F	35		32-bit binary string
Displays the status of DDB signals				
DDB 735 - 704	0F	36		32-bit binary string
Displays the status of DDB signals				
DDB 767 - 736	0F	37		32-bit binary string
Displays the status of DDB signals				
DDB 799 - 768	0F	38		32-bit binary string
Displays the status of DDB signals				
DDB 831 - 800	0F	39		32-bit binary string
Displays the status of DDB signals				
DDB 863 - 832	0F	3A		32-bit binary string
Displays the status of DDB signals				
DDB 895 - 864	0F	3B		32-bit binary string
DDB 927 - 896	0F	3C		32-bit binary string
Displays the status of DDB signals				
DDB 959 - 928	0F	3D		32-bit binary string
Displays the status of DDB signals				
DDB 991 - 960	0F	3E		32-bit binary string
Displays the status of DDB signals				
DDB 1023 - 992	0F	3F		32-bit binary string
Displays the status of DDB signals				
DDB 1055 - 1024	0F	40		32-bit binary string
Displays the status of DDB signals				
DDB 1087 - 1056	0F	41		32-bit binary string
Displays the status of DDB signals				
DDB 1119 - 1088	0F	42		32-bit binary string
Displays the status of DDB signals				
DDB 1151 - 1120	0F	43		32-bit binary string
Displays the status of DDB signals				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DDB 1183 - 1152	0F	44		32-bit binary string
Displays the status of DDB signals				
DDB 1215 - 1184	0F	45		32-bit binary string
Displays the status of DDB signals				
DDB 1247 - 1216	0F	46		32-bit binary string
Displays the status of DDB signals				
DDB 1279 - 1248	0F	47		32-bit binary string
Displays the status of DDB signals				
DDB 1311 - 1280	0F	48		32-bit binary string
Displays the status of DDB signals				
DDB 1343 - 1312	0F	49		32-bit binary string
Displays the status of DDB signals				
DDB 1375 - 1344	0F	4A		32-bit binary string
Displays the status of DDB signals				
DDB 1407 - 1376	0F	4B		32-bit binary string
Displays the status of DDB signals				
DDB 1439 - 1408	0F	4C		32-bit binary string
Displays the status of DDB signals				
DDB 1471 - 1440	0F	4D		32-bit binary string
Displays the status of DDB signals				
DDB 1503 - 1472	0F	4E		32-bit binary string
Displays the status of DDB signals				
DDB 1535 - 1504	0F	4F		32-bit binary string
Displays the status of DDB signals				
DDB 1567 - 1536	0F	50		32-bit binary string
Displays the status of DDB signals				
DDB 1599 - 1568	0F	51		32-bit binary string
Displays the status of DDB signals				
DDB 1631 - 1600	0F	52		32-bit binary string
Displays the status of DDB signals				
DDB 1663 - 1632	0F	53		32-bit binary string
Displays the status of DDB signals				
DDB 1695 - 1664	0F	54		32-bit binary string
Displays the status of DDB signals				
DDB 1727 - 1696	0F	55		32-bit binary string
Displays the status of DDB signals				
DDB 1759 - 1728	0F	56		32-bit binary string
Displays the status of DDB signals				
DDB 1791 - 1760	0F	57		32-bit binary string
Displays the status of DDB signals				
DDB 1823 - 1792	0F	58		32-bit binary string
Displays the status of DDB signals				
DDB 1855 - 1824	0F	59		32-bit binary string

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Displays the status of DDB signals				
DDB 1887 - 1856	0F	5A		32-bit binary string
Displays the status of DDB signals				
DDB 1919 - 1888	0F	5B		32-bit binary string
Displays the status of DDB signals				
DDB 1951 - 1920	0F	5C		32-bit binary string
Displays the status of DDB signals				
DDB 1983 - 1952	0F	5D		32-bit binary string
Displays the status of DDB signals				
DDB 2015 - 1984	0F	5E		32-bit binary string
Displays the status of DDB signals				
DDB 2047 - 2016	0F	5F		32-bit binary string
Displays the status of DDB signals				

Table 47 - Commissioning tests menu cells

5.17 Circuit Breaker Condition Monitor Setup

The Circuit Breaker condition monitoring includes features to monitor the CB condition such as the current broken, number of CB operations, number of CB operations in a set time and CB operating time. Alarms or a circuit breaker lockout can be raised for different threshold values.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CB MONITOR SETUP	10	00		
This column contains circuit breaker monitor settings				
Broken I^	10	01	2	1 to 2 step 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	10	02	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	10	03	1000A	From 1A to 25kA step 1A
Setting that determines the threshold for the cumulative I^ maintenance counter monitors.				
I^ Lockout	10	04	Alarm Disabled	Alarm Disabled, Alarm Enabled
Setting which determines if a lockout will be raised or not when the cumulative I^ maintenance counter threshold is exceeded.				
I^ Lockout	10	05	2000A	From 1A to 25kA step 1A
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	10	06	Alarm Disabled	Alarm Disabled, Alarm Enabled
Setting to activate the number of circuit breaker operations maintenance alarm.				
No. CB Ops Maint	10	07	10	1 to 10000 step 1
Sets the threshold for number of circuit breaker operations alarm				
No. CB Ops Lock	10	08	Alarm Disabled	Alarm Disabled, Alarm Enabled
Setting to activate the number of circuit breaker operations maintenance lockout				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
No. CB Ops Lock	10	09	20	1 to 10000 step 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	10	0A	Alarm Disabled	Alarm Disabled, Alarm Enabled
Setting to activate the circuit breaker operating time maintenance alarm.				
CB Time Maint	10	0B	100 ms	0.005s to 0.5s step 0.001s
Setting for the circuit breaker operating time alarm threshold which is set in relation to the specified interrupting time of the circuit breaker.				
CB Time Lockout	10	0C	Alarm Disabled	Alarm Disabled, Alarm Enabled
Setting to activate the circuit breaker operating time maintenance lockout				
CB Time Lockout	10	0D	200 ms	0.005s to 0.5s step 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	10	0E	Alarm Disabled	Alarm Disabled, Alarm Enabled
Enables the excessive fault frequency lockout				
Fault Freq Count	10	0F	10	1 to 9999 step 1
Sets a circuit breaker frequent operations counter that monitors the number of operations over a set time period				
Fault Freq Time	10	10	3600 s	0s to 9999s step 1s
Sets the time period over which the circuit breaker operations are to be monitored. Should the set number of trip operations be accumulated within this time period, an alarm can be raised. Excessive fault frequency/trips can be used to indicate that the circuit may need maintenance attention (e.g. Tree-felling or insulator cleaning).				

Table 48 - Circuit breaker condition monitoring menu

5.18 Opto Configuration

Courier Text	Col	Row	Default Setting	Available Setting
Description				
OPTO CONFIG	11	00		
This column contains opto-input configuration settings				
Global Nominal V	11	01	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V, 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	11	02	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 2	11	03	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 3	11	04	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 4	11	05	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 5	11	06	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 6	11	07	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 7	11	08	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 8	11	09	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 9	11	0A	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 10	11	0B	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 11	11	0C	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 12	11	0D	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 13	11	0E	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 14	11	0F	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 15	11	10	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 16	11	11	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Opto Input 17	11	12	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 18	11	13	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 19	11	14	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 20	11	15	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 21	11	16	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 22	11	17	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 23	11	18	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 24	11	19	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 25	11	1A	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 26	11	1B	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 27	11	1C	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 28	11	1D	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 29	11	1E	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 30	11	1F	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 31	11	20	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Input 32	11	21	48/54V	24/27V, 30/34V, 48/54V, 110/125V, 220/250V
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting. The number of inputs depends on the IED and I/O configuration.				
Opto Filter Ctrl	11	50	11111111111111111111111111111111(bin)	16 bit binary string (0 disable filtering, 1 enable filtering)
Selects each of the inputs with a pre-set filter of ½ cycle that renders the input immune to induced noise on the wiring. The number of available bits depends on the I/O configuration.				
Characteristic	11	80	Standard 60%-80%	0 = Standard 60%-80%, 1 = 50%-70%
Selects the pick-up and drop-off characteristics of the opto's. 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 49 - Opto inputs configuration settings

5.19 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.
This column is visible when the “Control I/P Config” setting (“Configuration” column) = “visible”.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CONTROL INPUTS	12	00		
This column contains settings for the type of control input (32 in all)				
Ctrl I/P Status	12	01		32-bit binary setting: 0=Reset or 1=Set
Cell that is used to set (1) and reset (0) the selected Control Input by simply scrolling and changing the status of selected bits. This command will be then recognized and executed in the PSL. Alternatively, each of the 32 Control input can also be set and reset using the individual menu setting cells as follows:				
Control Input 1	12	02	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 1 set/ reset.				
Control Input 2	12	03	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 2 set/ reset.				
Control Input 3	12	04	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 3 set/ reset.				
Control Input 4	12	05	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 4 set/ reset.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Control Input 5	12	06	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 5 set/ reset.				
Control Input 6	12	07	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 6 set/ reset.				
Control Input 7	12	08	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 7 set/ reset.				
Control Input 8	12	09	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 8 set/ reset.				
Control Input 9	12	0A	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 9 set/ reset.				
Control Input 10	12	0B	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 10 set/ reset.				
Control Input 11	12	0C	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 11 set/ reset.				
Control Input 12	12	0D	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 12 set/ reset.				
Control Input 13	12	0E	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 13 set/ reset.				
Control Input 14	12	0F	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 14 set/ reset.				
Control Input 15	12	10	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 15 set/ reset.				
Control Input 16	12	11	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 16 set/ reset.				
Control Input 17	12	12	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 17 set/ reset.				
Control Input 18	12	13	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 18 set/ reset.				
Control Input 19	12	14	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 19 set/ reset.				
Control Input 20	12	15	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 20 set/ reset.				
Control Input 21	12	16	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 21 set/ reset.				
Control Input 22	12	17	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 22 set/ reset.				
Control Input 23	12	18	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 23 set/ reset.				
Control Input 24	12	19	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 24 set/ reset.				
Control Input 25	12	1A	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 25 set/ reset.				
Control Input 26	12	1B	No Operation	0 = No Operation, 1 = SET , 2 = RESET

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Setting to allow Control Inputs 26 set/ reset.				
Control Input 27	12	1C	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 27 set/ reset.				
Control Input 28	12	1D	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 28 set/ reset.				
Control Input 29	12	1E	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 30 set/ reset.				
Control Input 30	12	1F	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 30 set/ reset.				
Control Input 31	12	20	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 31 set/ reset.				
Control Input 32	12	21	No Operation	0 = No Operation, 1 = SET , 2 = RESET
Setting to allow Control Inputs 32 set/ reset.				

Table 50 - Control inputs settings

5.20 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”.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CTRL I/P CONFIG	13	00		
This column contains settings for the type of control input (32 in all)				
Hotkey Enabled	13	01	11111111111111111111111111111111(bin)	32-bit binary setting: 0=Not accessible via Hotkey Menu or 1=Accessible via Hotkey Menu
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. Not available on Chinese version relays.				
Control Input 1	13	10	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 1	13	11	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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	13	14	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 2	13	15	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 3	13	18	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 3	13	19	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 4	13	1C	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 4	13	1D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 5	13	20	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 5	13	21	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 6	13	24	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 6	13	25	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 7	13	28	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 7	13	29	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 8	13	2C	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 8	13	2D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 9	13	30	Latched	0 = Latched or 1 = Pulsed

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 9	13	31	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 10	13	34	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 10	13	35	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 11	13	38	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 11	13	39	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 12	13	3C	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 12	13	3D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 13	13	40	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 13	13	41	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 14	13	44	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 14	13	45	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 15	13	48	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Ctrl Command 15	13	49	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 16	13	4C	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 16	13	4D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 17	13	50	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 17	13	51	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 18	13	54	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 18	13	55	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 19	13	58	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 19	13	59	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 20	13	5C	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 20	13	5D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 21	13	60	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 21	13	61	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 22	13	64	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 22	13	65	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 23	13	68	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 23	13	69	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 24	13	6C	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 24	13	6D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 25	13	70	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 25	13	71	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 26	13	74	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 26	13	75	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 27	13	78	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 27	13	79	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 28	13	7C	Latched	0 = Latched or 1 = Pulsed

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 28	13	7D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 29	13	80	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 29	13	81	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 30	13	84	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 30	13	85	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 31	13	88	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 31	13	89	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 32	13	8C	Latched	0 = Latched or 1 = 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 10 ms after the set command is given and will then reset automatically (i.e. no reset command required).				
Ctrl Command 32	13	8D	SET/RESET	0 = ON/OFF, 1 = SET/RESET, 2 = IN/OUT, 3 = ENABLED/DISABLED
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 51 - Control inputs configuration settings

5.21 Function Keys

User programmable function keys are available on P343/P344/P345 relays.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
FUNCTION KEYS	17	00		
This column contains the function key definitions				
Fn Key Status	17	01		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Displays the status of each function key.				
Fn Key 1	17	02	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
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	17	03	Toggled	0 = Normal or 1 = Toggled
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 IED functions. In the 'Normal' mode the function key output will remain 'high' as long as key is pressed.				
Fn Key 1 Label	17	04	Function Key 1	From 32 to 234 step 1
Allows the text of the function key to be changed to something more suitable for the application.				
Fn Key 2	17	05	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 2 Mode	17	06	Normal	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 2 Label	17	07	Function Key 2	From 32 to 234 step 1
Same description as Fn Key 1 Label				
Fn Key 3	17	08	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 3 Mode	17	09	Normal	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 3 Label	17	0A	Function Key 3	From 32 to 234 step 1
Same description as Fn Key 1 Label				
Fn Key 4	17	0B	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 4 Mode	17	0C	Toggled	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 4 Label	17	0D	Function Key 4	From 32 to 234 step 1
Same description as Fn Key 1 Label				
Fn Key 5	17	0E	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 5 Mode	17	0F	Toggled	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 5 Label	17	10	Function Key 5	From 32 to 234 step 1
Same description as Fn Key 1 Label				
Fn Key 6	17	11	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 6 Mode	17	12	Toggled	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 6 Label	17	13	Function Key 6	From 32 to 234 step 1
Same description as Fn Key 1 Label				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Fn Key 7	17	14	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 7 Mode	17	15	Normal	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 7 Label	17	16	Function Key 7	From 32 to 234 step 1
Same description as Fn Key 1 Label				
Fn Key 8	17	17	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 8 Mode	17	18	Normal	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 8 Label	17	19	Function Key 8	From 32 to 234 step 1
Same description as Fn Key 1 Label				
Fn Key 9	17	1A	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 9 Mode	17	1B	Normal	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 9 Label	17	1C	Function Key 9	From 32 to 234 step 1
Same description as Fn Key 1 Label				
Fn Key 10	17	1D	Unlocked	0 = Disabled, 1 = Unlocked (Enabled), 2 = Locked
Same description as Fn Key 1				
Fn Key 10 Mode	17	1E	Normal	0 = Normal or 1 = Toggled
Same description as Fn Key 1 Mode				
Fn Key 10 Label	17	1F	Function Key 10	From 32 to 234 step 1
Same description as Fn Key 1 Label				

Table 52 - Function keys settings

5.22 Control Input Labels

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CTRL I/P LABELS	29	00		
This column contains settings for Control Input Labels				
Control Input 1	29	01	Control Input 1	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 2	29	02	Control Input 2	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 3	29	03	Control Input 3	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Control Input 4	29	04	Control Input 4	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 5	29	05	Control Input 5	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 6	29	06	Control Input 6	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 7	29	07	Control Input 7	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 8	29	08	Control Input 8	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 9	29	09	Control Input 9	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 10	29	0A	Control Input 10	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 11	29	0B	Control Input 11	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 12	29	0C	Control Input 12	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 13	29	0D	Control Input 13	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 14	29	0E	Control Input 14	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 15	29	0F	Control Input 15	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 16	29	10	Control Input 16	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 17	29	11	Control Input 17	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 18	29	12	Control Input 18	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 19	29	13	Control Input 19	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Control Input 20	29	14	Control Input 20	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 21	29	15	Control Input 21	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 22	29	16	Control Input 22	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 23	29	17	Control Input 23	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 24	29	18	Control Input 24	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 25	29	19	Control Input 25	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 26	29	1A	Control Input 26	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 27	29	1B	Control Input 27	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 28	29	1C	Control Input 28	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 29	29	1D	Control Input 29	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 30	29	1E	Control Input 30	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 31	29	1F	Control Input 31	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				
Control Input 32	29	20	Control Input 32	From 32 to 234 step 1
Text label to describe each individual control input. This text is displayed when a control input is accessed by the hotkey menu. It is displayed in the programmable scheme logic description of the control input				

Table 53 - Control input label settings

5.23 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.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
IED CONFIGURATOR	19	00		
This column contains settings for IED Configurator settings (IEC61850 builds)				
Switch Conf.Bank	19	05	No Action	0 = No action or 1 = 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 Conf.	19	0A	No Action	0 = No action or 1 = Restore Conf.
Used to restore data from MCL(MiCOM Configuration Language)/CID (Configured IED Descriptor) file. This file is specific, containing a single devices IEC61850 configuration information, and used for transferring data to/from the MiCOM IED.				
Active Conf.Name	19	10		Not Settable
The name of the configuration in the Active Memory Bank, usually taken from the SCL file.				
Active Conf.Rev	19	11		Not Settable
Configuration Revision number of the configuration in the Active Memory Bank, usually taken from the SCL file.				
Inact.Conf.Name	19	20		Not Settable
The name of the configuration in the Inactive Memory Bank, usually taken from the SCL file.				
Inact.Conf.Rev	19	21		Not Settable
Configuration Revision number of the configuration in the Inactive Memory Bank, usually taken from the SCL file.				
IP PARAMETERS	19	30		
IP PARAMETERS				
IP Address 1	19	31		Not Settable
Displays the unique network IP address that identifies the relay on interface 1. A default IP address is encoded from MAC address 169.254.0.xxx, xxx = mod (The last byte of MAC1, 128) + 1.				
Subnet Mask 1	19	32		Not Settable
Displays the sub-network mask for interface 1.				
Gateway 1	19	33		Not Settable
Displays the IP address of the gateway (proxy) that interface 1 is connected to.				
IP Address 2	19	34		Not Settable
Displays the unique network IP address that identifies the relay on interface 2. A default IP address is encoded from MAC address 169.254.1.xxx, xxx = mod (The last byte of MAC2, 128) + 1. Visible when redundant Ethernet card fitted.				
Subnet Mask 2	19	35		Not Settable
Displays the sub-network mask for interface 2. Visible when redundant Ethernet card fitted.				
Gateway 2	19	36		Not Settable
Displays the IP address of the gateway (proxy) that interface 2 is connected to. Visible when redundant Ethernet card fitted.				
SNTP PARAMETERS	19	40		
SNTP PARAMETERS				
SNTP Server 1	19	41		Not Settable
Displays the IP address of the primary SNTP server.				
SNTP Server 2	19	42		Not Settable
Displays the IP address of the secondary SNTP server. Visible when Ethernet card fitted.				
IEC 61850 SCL	19	50		
IEC 61850 SCL				
IED Name	19	51		Not Settable
IED name, which is the unique name on the IEC 61850 network for the IED, usually taken from the SCL (Substation Configuration Language for XML) file.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
IEC 61850 GOOSE	19	60		
IEC 61850 GOOSE				
GoEna	19	70	0000000000000000(bin)	Bit 00=gcb01 GoEna to Bit 0F=gcb16 GoEna
Setting to enable GOOSE publisher settings.				
Pub.Simul.Goose	19	71	0000000000000000(bin)	Bit 00=gcb01 Sim Mode to Bit 0F=gcb16 Sim Mode
The Pub.Simul.GOOSE cell controls whether GOOSE are sent as Normal or Simulated GOOSE. When a GOOSE control block is set to Sim Mode its GOOSE is published as simulated. Simulated GOOSE are usually published by test equipment and this setting allows a test IED to be set up to simulate the IEDs in a substation.				
Sub.Simul.Goose	19	73	No	0 = No or 1 = Yes
In edition 2 mode when Sub.Simul.GOOSE is set to Yes the relay will look for simulated GOOSE. If a simulated GOOSE is found the relay will subscribe to it and will not respond to its normal GOOSE until Sub.Simul.GOOSE is set to No. Other GOOSE signals that are not being simulated will remain subscribing to normal GOOSE. In edition 1 mode the relay will respond to both normal and test GOOSE.				

Table 54 - IEC-61850 IED configurator

5.24 Virtual Input Labels

Courier Text	Col	Row	Default Setting	Available Setting
Description				
VIR I/P LABELS	26	00		
This column contains settings for Virtual Input Labels				
Virtual Input 01	26	01	Virtual Input 1	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 02	26	02	Virtual Input 2	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 03	26	03	Virtual Input 3	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 04	26	04	Virtual Input 4	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 05	26	05	Virtual Input 5	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 06	26	06	Virtual Input 6	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 07	26	07	Virtual Input 7	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 08	26	08	Virtual Input 8	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 09	26	09	Virtual Input 9	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 10	26	0A	Virtual Input 10	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 11	26	0B	Virtual Input 11	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Virtual Input 12	26	0C	Virtual Input 12	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 13	26	0D	Virtual Input 13	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 14	26	0E	Virtual Input 14	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 15	26	0F	Virtual Input 15	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 16	26	10	Virtual Input 16	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 17	26	11	Virtual Input 17	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 18	26	12	Virtual Input 18	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 19	26	13	Virtual Input 19	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 20	26	14	Virtual Input 20	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 21	26	15	Virtual Input 21	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 22	26	16	Virtual Input 22	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 23	26	17	Virtual Input 23	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 24	26	18	Virtual Input 24	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 25	26	19	Virtual Input 25	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 26	26	1A	Virtual Input 26	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 27	26	1B	Virtual Input 27	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 28	26	1C	Virtual Input 28	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 29	26	1D	Virtual Input 29	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 30	26	1E	Virtual Input 30	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 31	26	1F	Virtual Input 31	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 32	26	20	Virtual Input 32	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 33	26	21	Virtual Input 33	From 32 to 234 step 1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Text label to describe each individual Virtual Input.				
Virtual Input 34	26	22	Virtual Input 34	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 35	26	23	Virtual Input 35	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 36	26	24	Virtual Input 36	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 37	26	25	Virtual Input 37	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 38	26	26	Virtual Input 38	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 39	26	27	Virtual Input 39	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 40	26	28	Virtual Input 40	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 41	26	29	Virtual Input 41	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 42	26	2A	Virtual Input 42	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 43	26	2B	Virtual Input 43	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 44	26	2C	Virtual Input 44	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 45	26	2D	Virtual Input 45	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 46	26	2E	Virtual Input 46	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 47	26	2F	Virtual Input 47	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 48	26	30	Virtual Input 48	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 49	26	31	Virtual Input 49	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 50	26	32	Virtual Input 50	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 51	26	33	Virtual Input 51	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 52	26	34	Virtual Input 52	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 53	26	35	Virtual Input 53	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 54	26	36	Virtual Input 54	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Virtual Input 55	26	37	Virtual Input 55	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 56	26	38	Virtual Input 56	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 57	26	39	Virtual Input 57	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 58	26	3A	Virtual Input 58	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 59	26	3B	Virtual Input 59	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 60	26	3C	Virtual Input 60	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 61	26	3D	Virtual Input 61	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 62	26	3E	Virtual Input 62	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 63	26	3F	Virtual Input 63	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				
Virtual Input 64	26	40	Virtual Input 64	From 32 to 234 step 1
Text label to describe each individual Virtual Input.				

Table 55 - Virtual Input labels settings

5.25 Virtual Output Labels

Courier Text	Col	Row	Default Setting	Available Setting
Description				
VIR O/P LABELS	27	00		
This column contains settings for Virtual Output Labels				
Virtual Output01	27	01	Virtual Output 1	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output02	27	02	Virtual Output 2	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output03	27	03	Virtual Output 3	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output04	27	04	Virtual Output 4	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output05	27	05	Virtual Output 5	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output06	27	06	Virtual Output 6	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output07	27	07	Virtual Output 7	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Virtual Output08	27	08	Virtual Output 8	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output09	27	09	Virtual Output 9	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output10	27	0A	Virtual Output10	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output11	27	0B	Virtual Output11	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output12	27	0C	Virtual Output12	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output13	27	0D	Virtual Output13	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output14	27	0E	Virtual Output14	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output15	27	0F	Virtual Output15	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output16	27	10	Virtual Output16	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output17	27	11	Virtual Output17	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output18	27	12	Virtual Output18	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output19	27	13	Virtual Output19	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output20	27	14	Virtual Output20	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output21	27	15	Virtual Output21	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output22	27	16	Virtual Output22	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output23	27	17	Virtual Output23	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output24	27	18	Virtual Output24	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output25	27	19	Virtual Output25	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output26	27	1A	Virtual Output26	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output27	27	1B	Virtual Output27	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output28	27	1C	Virtual Output28	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output29	27	1D	Virtual Output29	From 32 to 234 step 1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Text label to describe each individual Virtual Output.				
Virtual Output30	27	1E	Virtual Output30	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output31	27	1F	Virtual Output31	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output32	27	20	Virtual Output32	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output33	27	21	Virtual Output33	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output34	27	22	Virtual Output34	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output35	27	23	Virtual Output35	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output36	27	24	Virtual Output36	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output37	27	25	Virtual Output37	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output38	27	26	Virtual Output38	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output39	27	27	Virtual Output39	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output40	27	28	Virtual Output40	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output41	27	29	Virtual Output41	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output42	27	2A	Virtual Output42	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output43	27	2B	Virtual Output43	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output44	27	2C	Virtual Output44	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output45	27	2D	Virtual Output45	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output46	27	2E	Virtual Output46	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output47	27	2F	Virtual Output47	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output48	27	30	Virtual Output48	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output49	27	31	Virtual Output49	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output50	27	32	Virtual Output50	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Virtual Output51	27	33	Virtual Output51	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output52	27	34	Virtual Output52	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output53	27	35	Virtual Output53	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output54	27	36	Virtual Output54	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output55	27	37	Virtual Output55	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output56	27	38	Virtual Output56	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output57	27	39	Virtual Output57	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output58	27	3A	Virtual Output58	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output59	27	3B	Virtual Output59	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output60	27	3C	Virtual Output60	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output61	27	3D	Virtual Output61	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output62	27	3E	Virtual Output62	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output63	27	3F	Virtual Output63	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				
Virtual Output64	27	40	Virtual Output64	From 32 to 234 step 1
Text label to describe each individual Virtual Output.				

Table 56 - Virtual Output labels settings

5.26 User Alarm Labels

Courier Text	Col	Row	Default Setting	Available Setting
Description				
USR ALARM LABELS	28	00		
This column contains settings for User Alarm Labels				
SR User Alarm 1	28	01	SR User Alarm 1	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 2	28	02	SR User Alarm 2	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 3	28	03	SR User Alarm 3	From 32 to 234 step 1
Text label to describe each individual User Alarm.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
SR User Alarm 4	28	04	SR User Alarm 4	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 5	28	05	SR User Alarm 5	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 6	28	06	SR User Alarm 6	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 7	28	07	SR User Alarm 7	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 8	28	08	SR User Alarm 8	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 9	28	09	SR User Alarm 9	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 10	28	0A	SR User Alarm 10	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 11	28	0B	SR User Alarm 11	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 12	28	0C	SR User Alarm 12	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 13	28	0D	SR User Alarm 13	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 14	28	0E	SR User Alarm 14	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 15	28	0F	SR User Alarm 15	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
SR User Alarm 16	28	10	SR User Alarm 16	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 17	28	11	MR User Alarm 17	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 18	28	12	MR User Alarm 18	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 19	28	13	MR User Alarm 19	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 20	28	14	MR User Alarm 20	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 21	28	15	MR User Alarm 21	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 22	28	16	MR User Alarm 22	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 23	28	17	MR User Alarm 23	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 24	28	18	MR User Alarm 24	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 25	28	19	MR User Alarm 25	From 32 to 234 step 1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Text label to describe each individual User Alarm.				
MR User Alarm 26	28	1A	MR User Alarm 26	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 27	28	1B	MR User Alarm 27	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 28	28	1C	MR User Alarm 28	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 29	28	1D	MR User Alarm 29	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 30	28	1E	MR User Alarm 30	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 31	28	1F	MR User Alarm 31	From 32 to 234 step 1
Text label to describe each individual User Alarm.				
MR User Alarm 32	28	20	MR User Alarm 32	From 32 to 234 step 1
Text label to describe each individual User Alarm.				

Table 57 - User Alarm labels settings

OPERATION

CHAPTER 5

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

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FIGURES

TABLES

Notes:

1 OPERATION OF INDIVIDUAL PROTECTION FUNCTIONS

The following sections detail the individual protection functions.

1.1 Phase Rotation

A facility is provided in the P34x to maintain correct operation of all the protection functions even when the motor is running in a reverse phase sequence. This is achieved through user configurable settings available for the four setting groups.

The **Phase Sequence – Standard ABC/Reverse ACB** setting applies to a power system that has a permanent phase sequence of either ABC or ACB. It is also applicable for temporary phase reversal which affects all the VTs and CTs. As distinct from the other phase reversal settings, this setting does not perform any internal phase swapping of the analogue channels.

Standard ABC

The calculations of positive (I1, V1) and negative (I2, V2) phase sequence voltage and current remain unchanged as follows:

$$\overline{X_1} = \frac{1}{3}(\overline{X_a} + \alpha\overline{X_b} + \alpha^2\overline{X_c})$$

$$\overline{X_2} = \frac{1}{3}(\overline{X_a} + \alpha^2\overline{X_b} + \alpha\overline{X_c})$$

Reverse ACB

The calculations of positive (I1, V1) and negative (I2, V2) phase sequence voltage and current are given by the equations:

$$\overline{X_1} = \frac{1}{3}(\overline{X_a} + \alpha\overline{X_b} + \alpha^2\overline{X_c})$$

$$\overline{X_2} = \frac{1}{3}(\overline{X_a} + \alpha^2\overline{X_b} + \alpha\overline{X_c})$$

Where:

$\alpha = 1\angle 120°$

The Phase Sequence setting also affects the directional overcurrent protection as follows:

Phase Rotation	67 (Directional Overcurrent)
Standard ABC	Phase A use Ia, Vbc Phase B use Ib, Vca Phase C use Ic, Vab
Reverse ACB	Phase A use Ia, -Vbc Phase B use Ib, -Vca Phase C use Ic, -Vab

Table 1 - Phase rotation

The **VT Reversal**, **CT1 Reversal** and **CT2 Reversal – No Swap/ A-B Swapped/ B-C Swapped/ C-A Swapped** settings apply to applications where some or all of the voltage or current inputs are temporarily reversed, as in pump storage applications. The settings affect the order of the analogue channels in the relay and are set to emulate the order of the channels on the power system. So, assuming the settings emulate the change in phase configuration on the power system all the protection functions will naturally operate as per a standard phase rotation system. The phase sequence calculations and the protection functions all remain unchanged.

1.2 Generator Differential Protection (87G)

Circulating current differential protection operates on the principle that current entering and leaving a zone of protection will be equal. Any difference between these currents is indicative of a fault being present in the zone. If CTs are connected as shown in the *Principle of circulating current differential protection* diagram it can be seen that current flowing through the zone of protection will cause current to circulate around the secondary wiring. If the CTs are of the same ratio and have identical magnetizing characteristics they will produce identical secondary currents and so zero current will flow through the relay.

If a fault exists within the zone of protection there will be a difference between the output from each CT; this difference flowing through the relay causing it to operate.

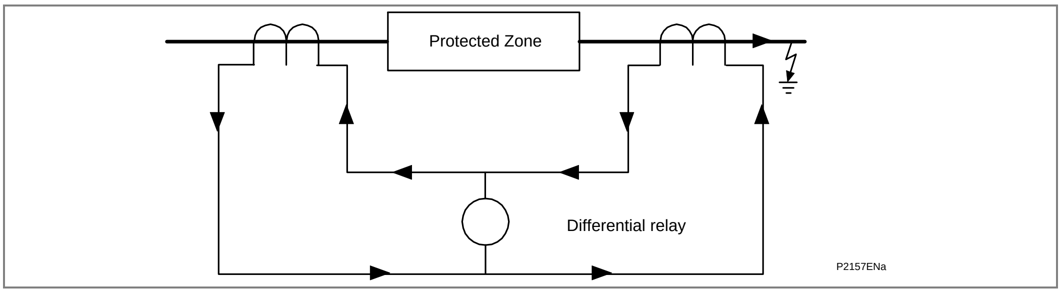


Figure 1 - Principle of circulating current differential protection

Heavy through current, arising from an external fault condition, can cause one CT to saturate more than the other, resulting in a difference between the secondary current produced by each CT. It is essential to stabilize the protection for these conditions. Two methods are commonly used. A biasing technique, where the relay setting is raised as through current increases. Alternatively, a high impedance technique, where the relay impedance is such that under maximum through fault conditions, the current in the differential element is insufficient for the relay to operate.

The generator differential protection function available in the P343/P344/P345 relay can be used in either biased differential or high impedance differential mode. Both modes of operation are equally valid; users may have a preference for one over the other. The operating principle of each is described in the following sections.

The generator differential protection may also be used for interturn protection that is described in the following sections.

The generator differential protection can be blocked by energizing the relevant DDB signal via the PSL (Gen Diff Block: DDB 512). If blocking of the generator differential protection or interturn protection is required from the CT supervision this must be done in PSL by connecting DDB 1263: CTS-1 Block OR DDB 1264: CTS-2 Block OR DDB 1265: CTS Block to DDB 512: Gen Diff Block.

A DDB (Digital Data Bus) signal is available to indicate the tripping of each phase of differential protection (DDB 737, DDB 738, DDB 739), in addition a three-phase trip DDB signal is provided (DDB 736). These signals are used to operate the output relays and trigger the disturbance recorder as programmed into the Programmable Scheme Logic (PSL). The state of the DDB signals can also be programmed to be viewed in the **Monitor Bit x** cells of the **COMMISSION TESTS** column in the relay.

The generator differential protection operation is shown in this diagram.

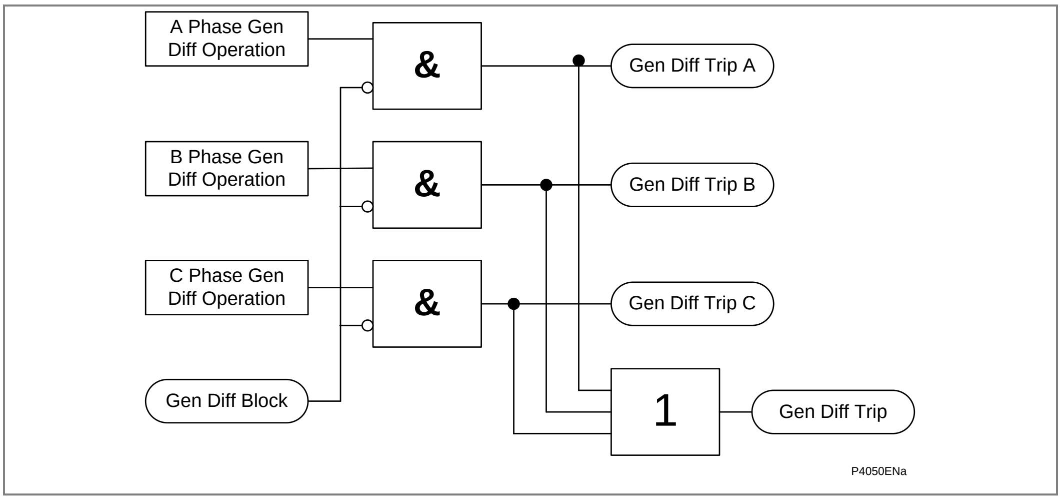


Figure 2 - Generator differential logic diagram

1.2.1 Biased Differential Protection

In a biased differential relay, the through current is used to increase the setting of the differential element. For heavy through faults, it is unlikely that the CT output at each zone end will be identical. This is due to the effects of CT saturation. In this case a differential current can be produced. However, the biasing will increase the relay setting, such that the differential spill current is insufficient to operate the relay.

A dual slope percentage bias characteristic is implemented in the relay. The lower slope provides sensitivity for internal faults, whereas the higher slope provides stability under through fault conditions, during which there may be transient differential currents due to saturation effect of the motor CTs.

The through current is calculated as the average of the scalar sum of the current entering and leaving the zone of protection. This calculated through current is then used to apply a percentage bias to increase the differential setting. The percentage bias can be varied to give the operating characteristic shown in the *Biased differential protection operating characteristic* diagram.

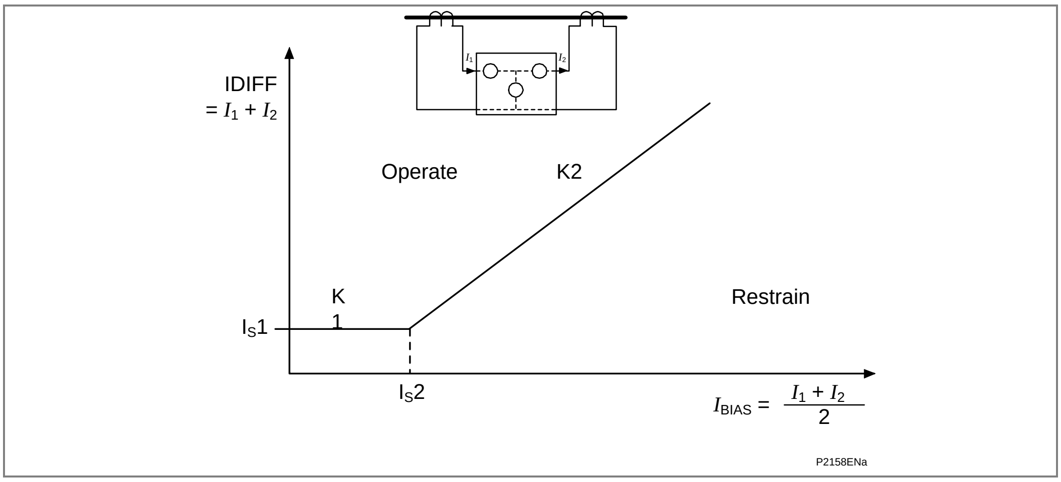


Figure 3 - Biased differential protection operating characteristic

Two bias settings are provided in the P343/P344/P345 relay. The initial bias slope, **Diff k1**, is applied for through currents up to **Diff Is2**. The second bias slope, **Diff k2**, is applied for through currents above the **Diff Is2** setting.

The Biased differential protection function uses the two sets of 3-phase current measurement inputs (IA, IB, IC, IA2, IB2, IC2), connected to measure the phase current at the neutral end and terminals of the machine, as shown in the *Biased differential protection operating characteristic* diagram. The bias and differential currents are calculated by the relay software, providing a phase segregated differential protection function, and may be viewed in the **MEASUREMENTS/MEAUREMENTS 1** column in the relay menu.

1.2.1.1 Differential and Bias Current Calculation

The calculation is performed on a per phase basis. The differential current is the vector sum of the phase currents measured at either end of the generator. The mean bias current (Ibias) is the scalar mean of the magnitude of these currents, i.e.

$$I_a - {}_{diff} = \left| \overline{I_a - 1} + \overline{I_a - 2} \right|$$

$$I_b - {}_{diff} = \left| \overline{I_b - 1} + \overline{I_b - 2} \right|$$

$$I_c - {}_{diff} = \left| \overline{I_c - 1} + \overline{I_c - 2} \right|$$

$$I_a - {}_{bias} = \frac{\left| \overline{I_a - 1} \right| + \left| \overline{I_a - 2} \right|}{2}$$

$$I_b - {}_{bias} = \frac{\left| \overline{I_b - 1} \right| + \left| \overline{I_b - 2} \right|}{2}$$

$$I_c - {}_{bias} = \frac{\left| \overline{I_c - 1} \right| + \left| \overline{I_c - 2} \right|}{2}$$

To provide further stability for external faults, a number of additional measures are taken on the bias calculations:

1.2.1.1.1 Delayed Bias

The bias quantity used is the maximum of the bias quantities calculated within the last cycle. This is to maintain the bias level, thus providing stability, during the time when an external fault is cleared. This feature is implemented on a per phase basis. The algorithm is expressed as follows; the function is executed 4 times per cycle:

Ia-bias(n) = Maximum [Ia-bias(n), Ia-bias(n-1), ..., Ia-bias(n - 3)]

Ib-bias(n) = Maximum [Ib-bias(n), Ib-bias(n-1),........., Ib-bias(n - 3)]

Ic-bias(n) = Maximum [Ic-bias(n), Ic-bias(n-1), ..., Ic-bias(n - 3)]

1.2.1.1.2 Transient Bias

An additional bias quantity is introduced into the bias calculation, on a per phase basis, if there is a sudden increase in the mean-bias measurement. This quantity decays exponentially afterwards. The transient bias is reset to zero once the relay has tripped or if the mean-bias quantity is below the Is1 setting. The transient bias is used to make the protection stable for external faults and allows for the time delay in CT saturation caused by small external fault currents and high X/R ratios. For single-end or double-end fed faults the differential current will be dominant and the transient bias will have no effect.

The transient bias is removed after the relay has tripped to avoid the possibility of chattering. It is also removed when Ibias is less than Is1 to avoid the possibility of residual values due to the numerical effects.

1.2.1.1.3 Maximum Bias

The bias quantity used per phase for the percentage bias characteristic is the maximum bias current calculated from all three phases, i.e.:

I-bias-max = Maximum [Ia-bias, Ib-bias, Ic-bias]

1.2.1.1.4 Tripping Criteria

The tripping criteria per phase are formulated as follows. The differential threshold changes according to the value of I-bias-max, as in the percentage bias characteristic.

Note	The transient bias is on a per phase basis and is not be affected by the K1 or K2 setting.

For I-bias-max <= Is2

Idiff > K1*I-bias-max + Transient_bias + Is1

For I-bias-max > Is2

Idiff > K2*I-bias-max + Transient Bias - Is2*(K2-K1) + Is1

A count strategy is used so that the protection will operate slower near the boundary of operation. This approach is used to stabilize the relay under some marginal transient conditions.

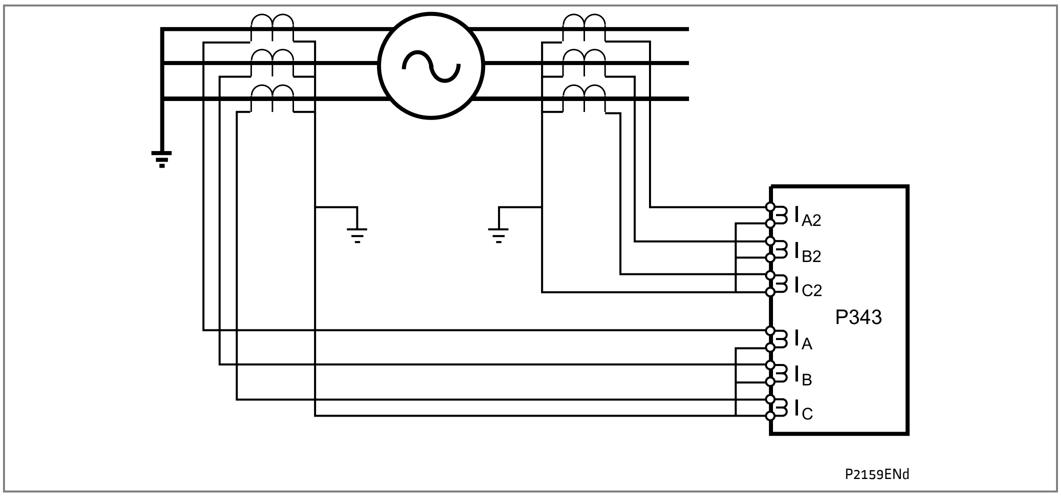
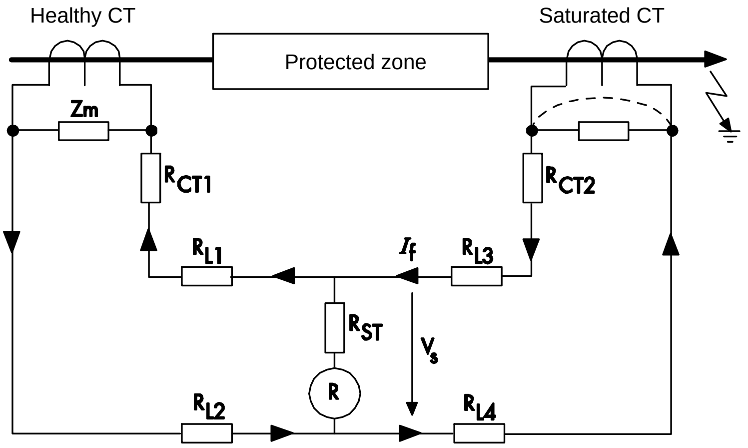


Figure 4 - Relay connections for biased differential protection

1.2.2 High Impedance Differential 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 the *Principle of high impedance differential protectio*n diagram.



Voltage across relay circuit

$V_S = KI_F/(R_{CT} + 2R_L)$ – where K=1.5

Stabilising resistor, R_{ST}, limits spill current to I_S (relay setting)

$$R_{ST} = \frac{V_S}{I_S} - R_R$$

Where
- I_F = Maximum secondary through fault current
- R_R = Relay burden
- R_{CT} = Current transformer secondary winding resistance
- R_L = Resistance of a single lead from the relay to the current transformer

P0115ENd

Figure 5 - Principle of high impedance differential protection

If the relay circuit is considered to be very high impedance, the secondary current produced by the healthy CT will flow through the saturated CT. If the 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 above. An additional non-linear resistor, 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 CTs used to operate the protection must have a knee point voltage of at least 2 Vs.

The high impedance differential protection function uses the IA2, IB2, IC2 current inputs connected to measure the differential current in each phase, as shown in below.

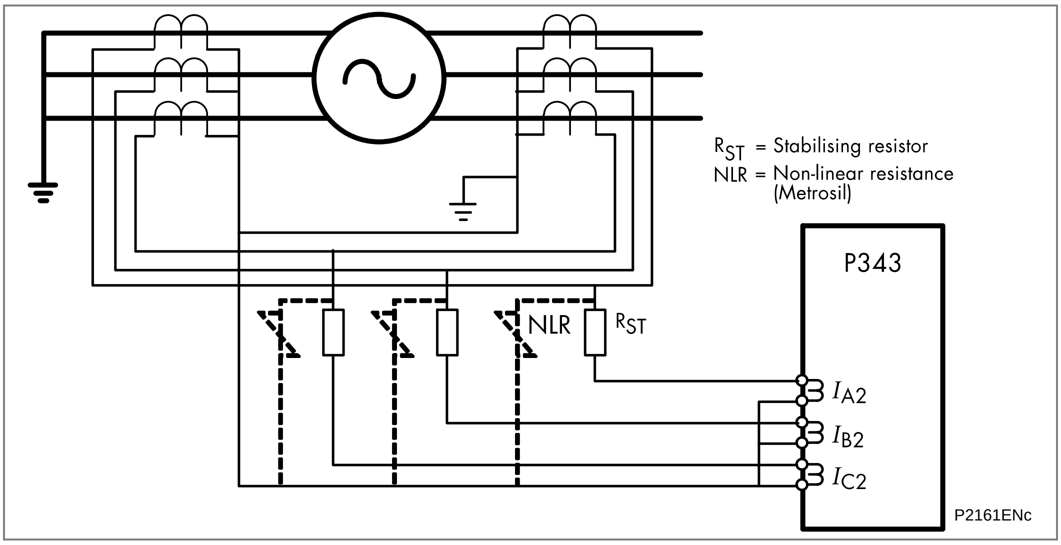


Figure 6 - Relay connections for high impedance differential protection

1.2.3 Interturn (Split Phase) Protection

For generators with multi-turn stator windings, there is the possibility of a winding inter-turn fault occurring. Unless such a fault evolves to become a stator earth fault, it will not otherwise be detected with conventional protection arrangements. Hydro generators usually involve multi-stator windings with parallel windings.

The P343/P344/P345 IA2/IB2/IC2 current inputs can be used for differential interturn protection and has independent settings per phase (**Interturn Is_A, Interturn Is_B, Interturn Is_C**). Therefore, the current setting can be increased on the faulted phase only without affecting the sensitivity of the protection on the other unfaulted phases. A time delay is used to prevent operation on CT transient error currents that may occur during external faults. The problem of CT transient error currents can be eliminated by using core balance (window) type CTs.

The interturn (split phase) protection operation is shown in the *Interturn logic* diagram:

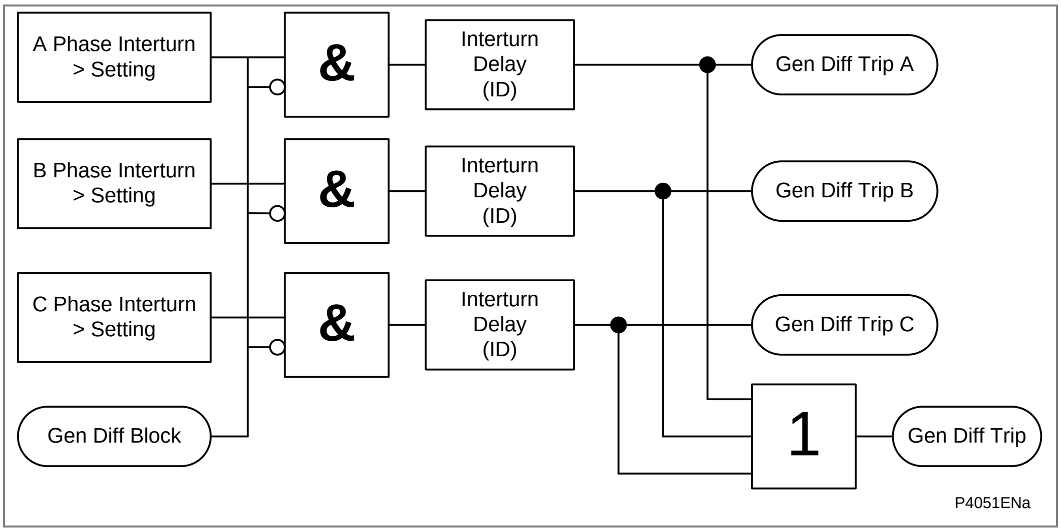


Figure 7 - Interturn logic diagram

1.3 Generator-Transformer Differential Protection (87GT)

The P343/P344/P345 differential protection is designed for the protection of a generator and 2 winding transformer.

For application of the device as generator-transformer differential protection, ratio correction is required. This is achieved simply by setting of the reference power generally the nominal power of the transformer and of the primary nominal voltages for all windings of the transformer. To minimize unbalance due to tap changer operation, current inputs to the differential element should be matched for the mid-tap position and not the nominal voltage.

Vector group matching is achieved by input of the relevant vector group identification number. Zero-sequence current filtering is also available. For conditions where it is possible to temporarily load the transformer with a voltage in excess of the nominal voltage, the overfluxing blocking prevents unwanted tripping. The 5th harmonic blocking feature does not require a voltage signal. A 5th harmonic signal is derived from the differential current waveform on each phase and blocking is on a per phase basis. The overfluxing protection should be used in such applications to protect the transformer accordingly.

1.3.1 Enabling or Disabling Differential Protection

Differential protection can be disabled or enabled from the local control panel. Moreover, enabling can be done separately for each setting group. To enable the differential protection, set the cell [0912: **Differential**] to enabled under the **CONFIGURATION** menu heading, and set the cell [3001: **Winding Config**] to **Xformer** under the **SYSTEM CONFIG** menu heading. Also the generator-transformer differential function must be enabled in the required setting group, for example, set the cell [3731: Xformer Diff] to enabled under **GROUP 1 Xformer Diff** menu heading. This enables setting group1 differential protection.

1.3.2 Ratio Correction

The relay automatically calculates the ratio correction factor for each winding. The reference power for the protected object, identical for all windings, needs to be defined. For two-winding arrangements, the nominal power will usually be the reference power. For three transformers, the nominal power of the highest-power winding should be set as the reference power. The reference power is set in the cell [3002: **Ref Power S**] under the **GROUP 1 SYSTEM CONFIG** menu heading.

The calculates the ratio correction factors on the basis of the reference power, winding nominal voltage, and primary nominal currents of the current transformers.

$$I_{ref,n} = \frac{S_{ref}}{\sqrt{3}V_{nom,n}} \qquad K_{amp,n} = \frac{I_{nom,n}}{\dfrac{S_{ref}}{\sqrt{3}V_{nom,n}}}$$

Sref:	common reference power for all ends
n:	is CT1 and CT2 for each of the CT inputs
Iref, n:	reference current for the respective CT input
Kamp, n:	amplitude-matching factor for the respective CT input
Inom, n:	primary nominal currents for the respective CT input
Vnom, n:	primary nominal voltage for the respective CT input

The relay checks that the matching factors are within their permissible ranges. The matching factors must satisfy the following condition:

- The matching factors must always be $0.05 \leq$ Kamp,n ≤ 20

If the relay calculates a matching factor that does not satisfy the above conditions, a warning, CT Mismatch Alm [DDB 396], is issued and the relay will be blocked automatically.

The *CT parameter mismatch logic diagram* is shown below.

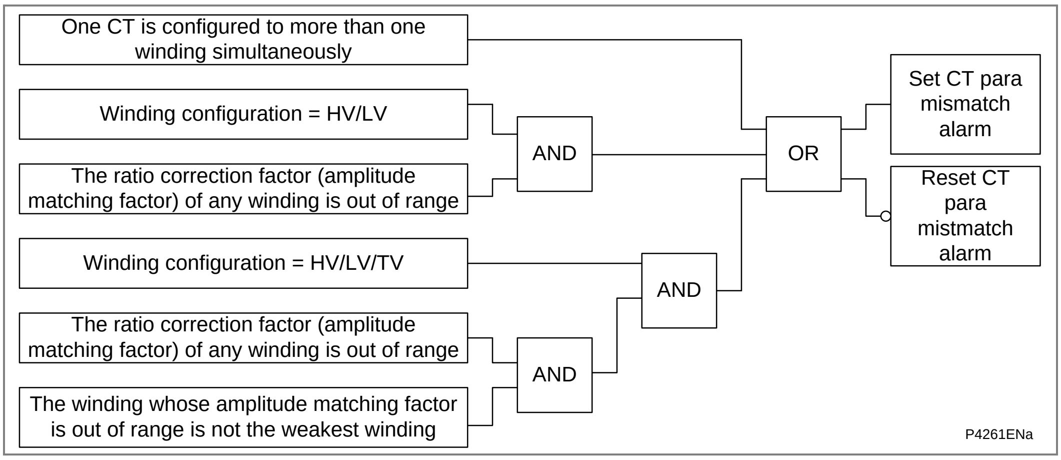


Figure 8 - CT parameter mismatch logic diagram

The measured values of the phase currents of the windings of the protected object are multiplied by the relevant matching factors and are then available for further processing. Consequently, all threshold values and measured values always refer back to the relevant reference currents rather than to the transformer nominal currents or the nominal currents of the device.

1.3.3 Vector Group Matching

The transformer HV windings are indicated by capital letters and the LV winding by lower case letters. The numbers refer to positions on a clock face and indicate the phase displacement of balanced 3-phase LV line currents with respect to balanced 3-phase HV line currents. The HV side is taken as reference and it is the 12 o'clock position. Therefore, each hour represents a 30° shift; i.e. 1 represents a 30° lag and 11 represents a 30° lead (LV with respect to HV). An additional N, YNd1, (lower case for LV, d) indicates a neutral to earth connection on the high voltage winding of the power transformer.

By studying the relative phase shifts that can be obtained, it can be seen that star-star windings allow even vector group configurations and star-delta/delta-star windings allow odd group configurations.

Examples

A YNd1 connection indicates a two winding transformer with an earthed, Star-connected, high voltage winding and a Delta-connected low voltage winding. The low voltage balanced line currents lag the high voltage balanced line currents by 30° (−30° phase shift).

A Dyn1yn11 connection indicates a three winding transformer with a Delta-connected high voltage winding and two earthed Star-connected low voltage windings. The phase displacement of the first LV winding with respect to the HV winding is 30° lag (−30° phase shift), the phase displacement of the second LV winding with respect to the HV winding is 30° lead (+30° phase shift).

Vector group matching is performed on the amplitude-matched phase currents of the low-voltage and tertiary voltage side in accordance with the characteristic vector group number.

When the relay is configured to protect a Yd1 transformer, the software interposing CTs used by the relay to achieve vector correction are as shown in Figure 9. No vector correction is performed on the HV amplitude matched phase currents. If the relay is in simple mode, the zero sequence filtering depends on the cell [**HV Grounding**]. The zero sequence filtering is applied when the cell [**HV Grounding**] under the **GROUP 1 SYSTEM CONFIG** menu heading is set to **Grounded**. Also, the cell [**Zero seq filt HV**] is changed to **Enabled** automatically. Otherwise, if the cell [**HV Grounding**] is set to **Ungrounded**, the cell [**Zero seq filt HV**] is changed to **Disabled** automatically.

If the relay is in advanced mode, the zero sequence filtering depends on the cell [**Zero seq filt HV**]. The zero sequence filtering is applied when the cell [**Zero seq filt HV**] under the **GROUP 1 DIFF PROTECTION** menu heading is set to **Enabled**. Also, the cell [**HV Grounding**] is changed to **Grounded** automatically. Otherwise, if the cell [**Zero seq filt HV**] is set to **Disabled**, the cell [**Zero seq filt HV**] is changed to **Ungrouded** automatically.

Therefore, on the Y high voltage side of the transformer the software interposing CT is either Yy0 (no zero sequence filtering is required) or Ydy0 (zero sequence filtering is required). The currents on the low voltage side lag by 30° the currents on the high voltage side due to the vector group (1). The relay brings the low voltage current in phase with the high voltage current by using a Yd11 software interposing CT on the low voltage side.

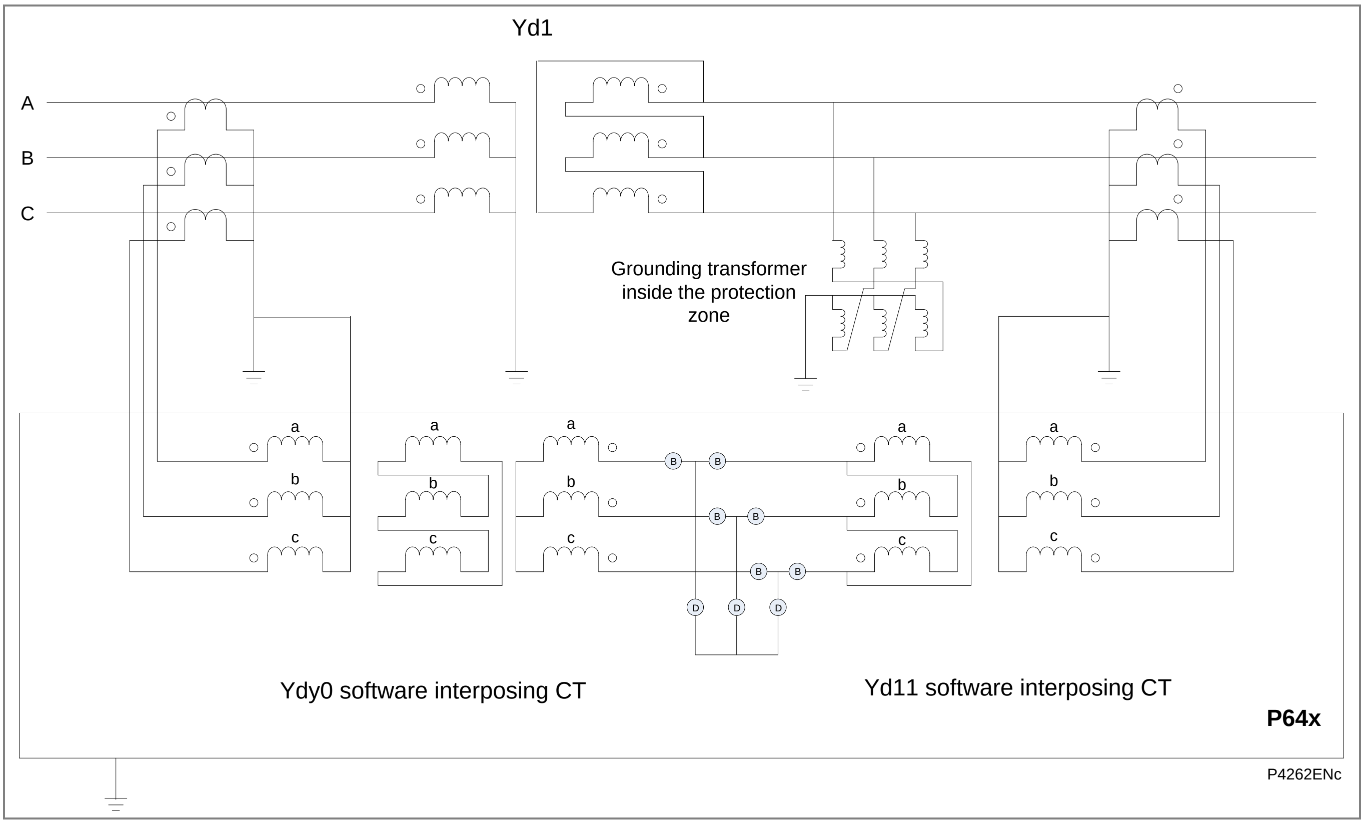


Figure 9 - Software interposing CTs for a Yd1 transformer

Consider the Y grounded winding of the Yd1 transformer during external ground faults on the high voltage side. Also consider that a source is connected to the delta side. The zero sequence component of the fault current flows through the grounded neutral that lies inside the transformer differential protection zone. The zero sequence component of the fault current is only seen by the CTs in the HV side. Therefore, zero sequence filtering for a Y grounded winding must be enabled to avoid undesirable tripping when an external ground fault occurs.

The Ydy0 software interposing CT is the equivalent of subtracting the zero sequence component from the phase currents on the high voltage side. The zero-sequence current is determined as follows from the amplitude-matched phase currents:

$$I_{amp,zero,n} = \frac{1}{3}\left(I_{amp,A,n}+I_{amp,B,n}+I_{amp,C,n}\right)$$

$$I_{amp,A,n,filtered}=I_{amp,A,n}-I_{amp,zero,n}$$

n:	CT1, CT2 for each of the CT inputs
Iamp, zero, n:	zero sequence amplitude matched current for the respective CT input
Iamp, A, n:	phase A amplitude matched current of the respective CT input

The grounding transformer connected to the LV side of the power transformer provides a path for LV ground faults. To avoid misoperation during external ground faults the zero sequence component needs to be filtered. In addition, the LV currents need to be in phase with the HV currents. The relay achieves zero sequence filtering and vector correction by using a Yd11 software interposing CT.

As previously discussed, star-star windings allow even vector group configurations and star-delta/delta-star windings allow odd group configurations. The following tables show that for all odd-numbered vector group characteristics the zero-sequence current on the low-voltage side is basically always filtered out, whereas for even-numbered vector group characteristics the zero-sequence current on the low-voltage side is never filtered out automatically. The latter is also true for the high-voltage side since in that case, as explained above, no vector correction is performed.

Vector group matching and zero-sequence current filtering must always be viewed in combination. The following tables list the mathematical phasor operations executed by the relay during vector correction.

- Table 2 - Phasor operations on the HV side
- Table 3 - Phasor operations on the LV side of Yy power transformers
- Table 4 - Phasor operations on the LV side of Yd or Dy power transformers

The indices in the formulae have the following meaning:

am: amplitude-matched
s: amplitude- and vector group-matched
x: phase A, B or C
y: differential measuring system that corresponds to phases A, B or C.
n: CT1, CT2 for each of the CT inputs
x+1: cyclically lagging phase
x-1: cyclically leading phase

No vector correction is done on the HV side of the transformer. Only zero sequence filtering is carried on if in the simple mode the winding is set as grounded or if in the advanced mode the high voltage zero sequence filter is enabled. As a result, the relay may perform the following mathematical operations on the HV side:

	With I_{zero} filtering	Without I_{zero} filtering
0	$I_{vec,y,n} = I_{amp,x,n} - I_{amp,zero,n}$	$I_{vec,y,n} = I_{amp,x,n}$

Table 2 - Phasor operations on the HV side

The following *Yy transformer connections* diagram shows the various even-numbered vector group configurations:

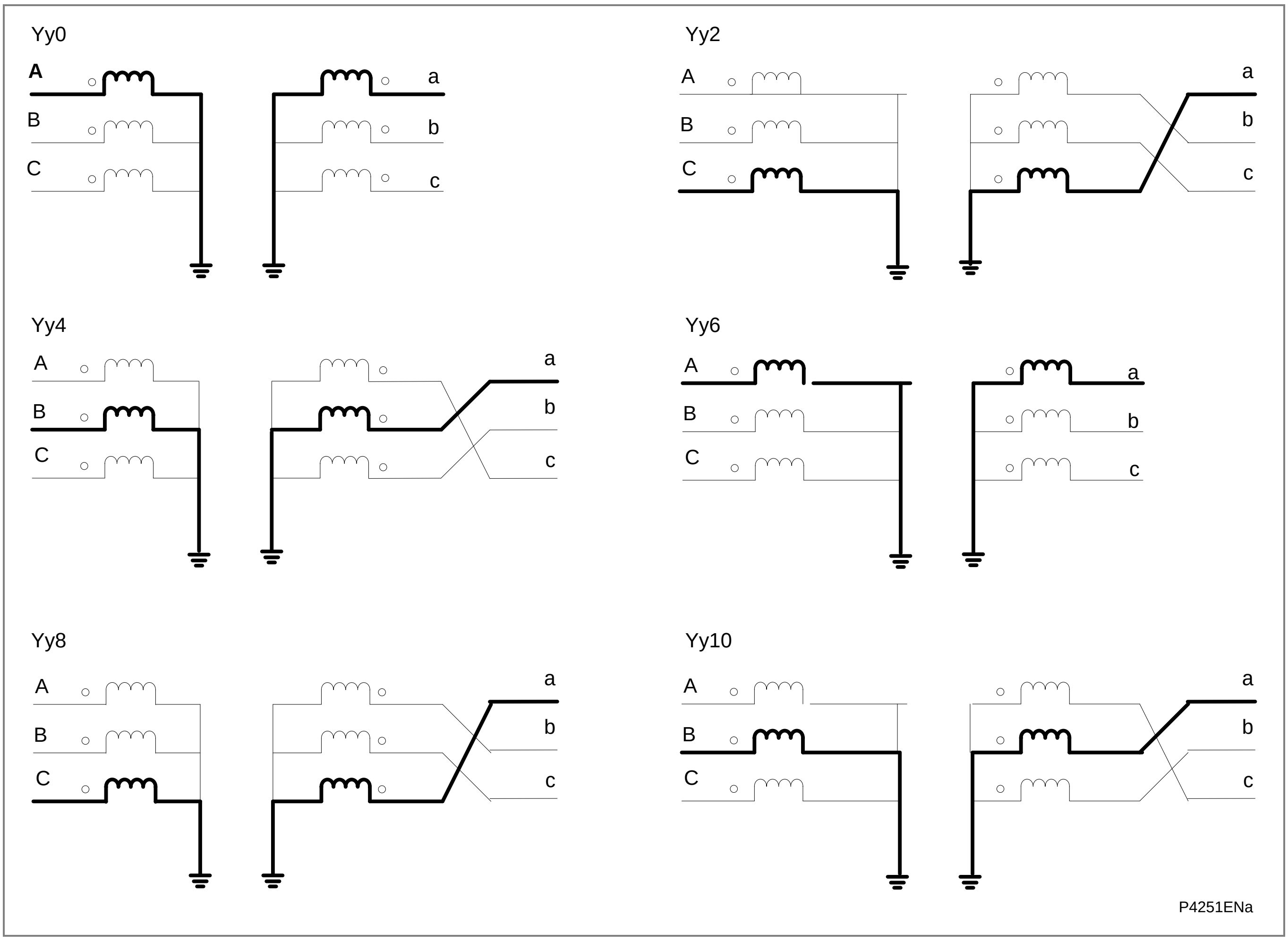


Figure 10 - Yy transformer connections

Consider the configurations as shown in the above *Yy transformer connections* diagram.

- In a Yy0 power transformer configuration, the LV currents are already in phase with the HV currents. Therefore, the relay only filters the zero sequence current as required.
- In a Yy2 power transformer configuration, the LV currents lag the HV currents by 60°. To bring the LV currents in phase with the HV currents, the relay uses a Yy10 software interposing CT.
- In a Yy4 power transformer configuration, the LV currents lag the HV currents by 120°. To bring the LV currents in phase with the HV currents, the relay uses a Yy8 software interposing CT.
- In a Yy6 power transformer configuration, the LV currents lag the HV currents by 180°. To bring the LV currents in phase with the HV currents, the relay uses a Yy6 software interposing CT.
- In a Yy8 power transformer configuration, the LV currents lead the HV currents by 120°. To bring the LV currents in phase with the HV currents, the relay uses a Yy4 software interposing CT.
- In a Yy10 power transformer configuration, the LV currents lead the HV currents by 60°. To bring the LV currents in phase with the HV currents, the relay uses a Yy2 software interposing CT.

The following *Phasor operations on the LV side of Yy power transformers* table shows the mathematical operations, equivalent to the corresponding software interposing CT, on the low-voltage side for an even-numbered vector group characteristic.

VG	With I_{zero} filtering	Without I_{zero} filtering
0	$I_{vec,y,n} = I_{amp,x,n} - I_{amp,zero,n}$	$I_{vec,y,n} = I_{amp,x,n}$
2	$I_{vec,y,n} = -\left(I_{amp,x+1,n} - I_{amp,zero,n}\right)$	$I_{vec,y,n} = -I_{amp,x+1,n}$
4	$I_{vec,y,n} = I_{amp,x-1,n} - I_{amp,zero,n}$	$I_{vec,y,n} = I_{amp,x-1,n}$
6	$I_{vec,y,n} = -\left(I_{amp,x,n} - I_{amp,zero,n}\right)$	$I_{vec,y,n} = -I_{amp,x,n}$
8	$I_{vec,y,n} = I_{amp,x+1,n} - I_{amp,zero,n}$	$I_{vec,y,n} = I_{amp,x+1,n}$
10	$I_{vec,y,n} = -\left(I_{amp,x-1,n} - I_{amp,zero,n}\right)$	$I_{vec,y,n} = -I_{amp,x-1,n}$

Table 3 - Phasor operations on the LV side of Yy power transformers

The following *Software interposing CTs for a Yy0 transformer* diagram shows the software interposing CTs used by the relay when a Yy0 power transformer is being protected. Notice that zero sequence filter is enabled on the HV and LV sides since Ydy0 interposing CTs are being used.

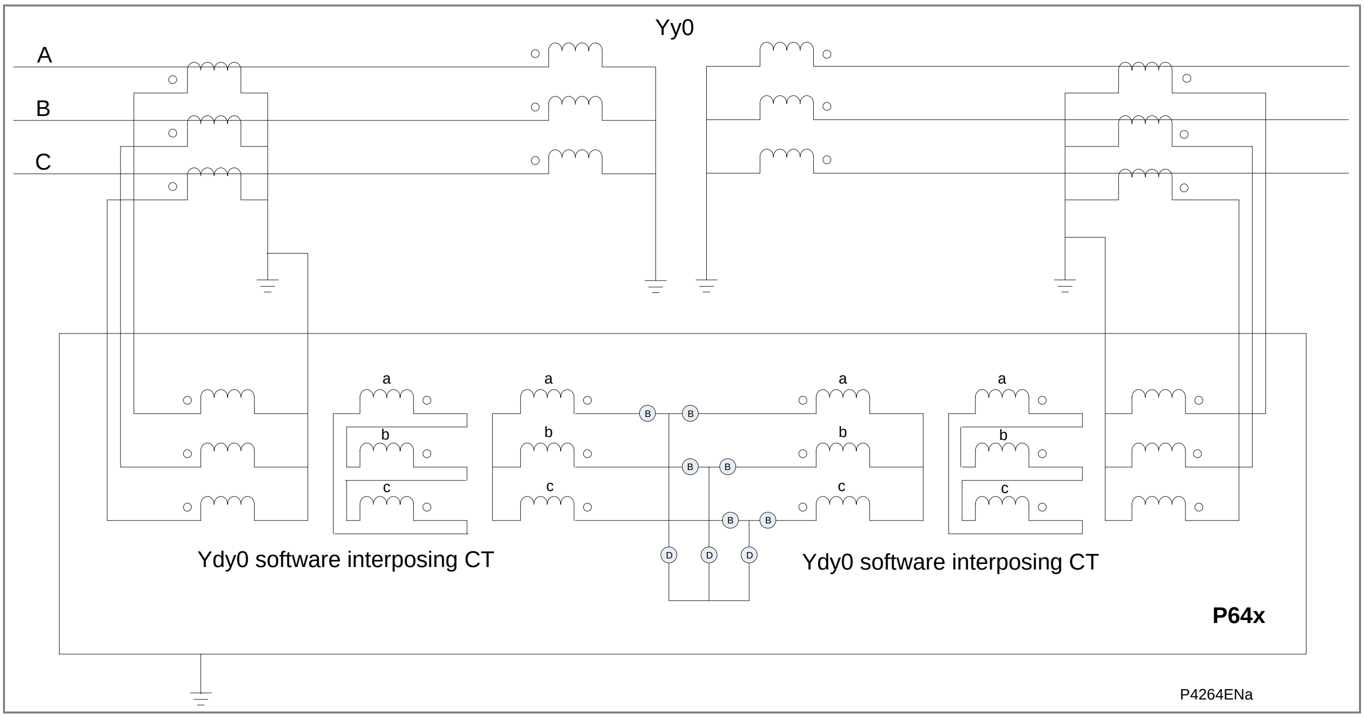


Figure 11 - Software interposing CTs for a Yy0 transformer

The following *Yd or Dy transformer connections* diagram shows the various odd-numbered vector group configurations:

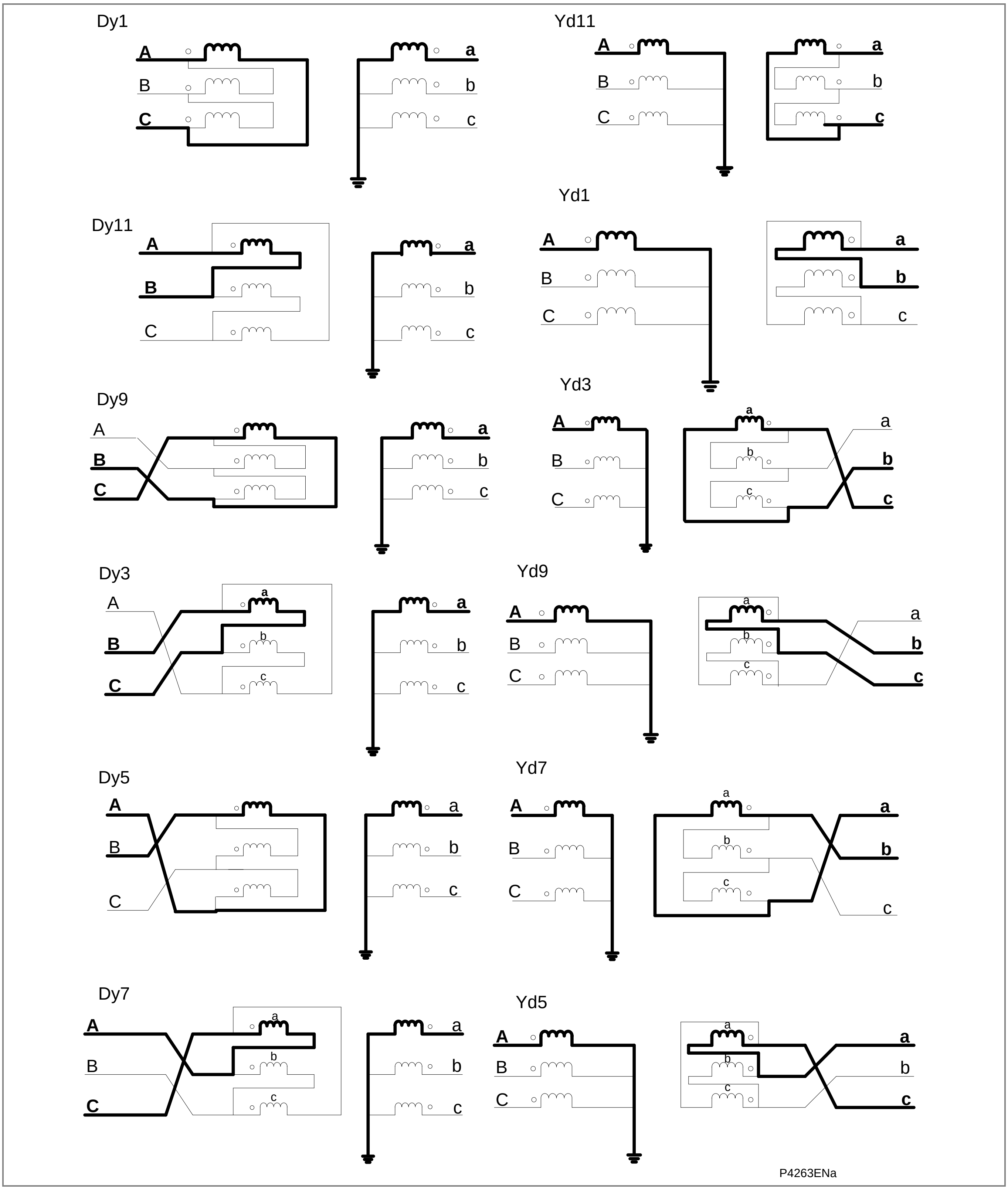


Figure 12 - Yd or Dy transformer connections

Consider the configurations shown in the above *Yd or Dy transformer connections* diagram.

- In a Dy1 or Yd1 power transformer configuration, the LV currents lag the HV currents by 30°. The relay uses a Yd11 software interposing CT to bring the LV currents in phase with the HV currents.
- In a Dy3 or Yd3 power transformer configuration, the LV currents lag the HV currents by 90°. The relay uses a Yd9 software interposing CT to bring the LV currents in phase with the HV currents.
- In a Dy5 or Yd5 power transformer configuration, the LV currents lag the HV currents by 150°. The relay uses a Yd7 software interposing CT to bring the LV currents in phase with the HV currents.
- In a Dy7 or Yd7 power transformer configuration, the LV currents lead the HV currents by 150°. The relay uses a Yd5 software interposing CT to bring the LV currents in phase with the HV currents.
- In a Dy9 or Yd9 power transformer configuration, the LV currents lead the HV currents by 90°. The relay uses a Yd3 software interposing CT to bring the LV currents in phase with the HV currents.
- In a Dy11 or Yd11 power transformer configuration, the LV currents lead the HV currents by 30°. The relay uses a Yd1 software interposing CT to bring the LV currents in phase with the HV currents.

The following *Phasor operations on the LV side of Yd or Dy power transformers* table shows the mathematical operations, equivalent to the corresponding software interposing CT, on the low-voltage side for an odd-numbered vector group characteristic:

VG	With or without I_{zero} filtering
1	$I_{vec,y,n} = \frac{1}{\sqrt{3}} \cdot \left(I_{amp,x,n} - I_{amp,x+1,n}\right)$
3	$I_{vec,y,n} = \frac{1}{\sqrt{3}} \cdot \left(I_{amp,x-1,n} - I_{amp,x+1,n}\right)$
5	$I_{vec,y,n} = \frac{1}{\sqrt{3}} \cdot \left(I_{amp,x-1,n} - I_{amp,x,n}\right)$
7	$I_{vec,y,n} = \frac{1}{\sqrt{3}} \cdot \left(I_{amp,x+1,n} - I_{amp,x,n}\right)$
9	$I_{vec,y,n} = \frac{1}{\sqrt{3}} \cdot \left(I_{amp,x+1,n} - I_{amp,x-1,n}\right)$
11	$I_{vec,y,n} = \frac{1}{\sqrt{3}} \cdot \left(I_{amp,x,n} - I_{amp,x-1,n}\right)$

Table 4 - Phasor operations on the LV side of Yd or Dy power transformers

Vector group matching is by input of the vector group identification number provided that the phase currents of the high and low voltage side(s) are connected in standard configuration. For other configurations, special considerations may apply. A reverse phase rotation (phase sequence A-C-B) needs to be taken into account by making the appropriate setting at the relay. The relay will then automatically form the complementary value of the set vector group ID to the number 12 (vector group ID = 12 - set ID).

1.3.4 Tripping Characteristics

The differential and bias currents for each phase are calculated from the current variables after amplitude and vector group matching.

Calculation of differential and biased currents is as follows:

$$I_{diff} = \left|\underline{I}_1 + \underline{I}_2\right|$$

$$I_{bias} = \frac{\left|\underline{I}_1\right| + \left|\underline{I}_2\right|}{2}$$

y is the measuring system that corresponds to phases A, B or C.
s is the current after the amplitude and vector group are matched.
To provide further stability for external faults, additional measures are considered on the calculation of the bias current:

1.3.4.1 Delayed Bias

The bias quantity used is the maximum of the bias quantities calculated within the last cycle. This is to maintain the bias level, thus providing stability, during the time when an external fault is cleared. This feature is implemented on a per phase basis. The algorithm is expressed as follows; the function is executed 4 times per cycle:

$I_{bias},y(n)$ = Maximum [$I_{bias},y(n)$, I_{bias},y (n-1), ..., I_{bias},y (n – 3)]

1.3.4.2 Transient Bias

An additional bias quantity is introduced into the bias calculation, on a per phase basis, if there is a sudden increase in the mean-bias measurement. This quantity decays exponentially afterwards. The transient bias is reset to zero once the relay has tripped or if the mean-bias quantity is below the Is1 setting. The transient bias is used to make the protection stable for external faults and allows for the time delay in CT saturation caused by small external fault currents and high X/R ratios. For single-end or double-end fed faults the differential current will be dominant and the transient bias will have no effect.

The transient bias is removed after the relay has tripped to avoid the possibility of chattering. It is also removed when Ibias is less than Is1 to avoid the possibility of residual values due to the numerical effects.

No transient bias is produced under load switching conditions. Also, no transient bias is generated when the CT comes out of saturation.

1.3.4.3 Maximum Bias

The bias quantity used per phase for the percentage bias characteristic is the maximum bias current calculated from all three phases, i.e.:

$I_{bias,max}$ = Maximum [I_{bias},A, I_{bias},B, I_{bias},C]

The bias currents are available as measurements displays and in the fault records. These currents are the mean bias from all the windings before any additional bias is added.

The tripping characteristic of the differential protection device relay has two knees. The first knee is dependent on the settings of **Is1** and **K1**. The second knee of the tripping characteristic is defined by the setting **Is2**. The lower slope provides sensitivity for internal faults. The higher slope provides stability under through fault conditions, since transient differential currents may be present due to current transformer saturation.

The characteristic equations for the three different ranges are given below. The *Tripping characteristic of differential protection* diagram shows the tripping characteristic.

Characteristic equation for the range: $0 \le I_{bias} \le \frac{I_{s1}}{K_1}$:

$$I_{diff} = I_{s1}$$

Characteristic equation for the range: $\frac{I_{s1}}{K_1} \le I_{bias} \le I_{s2}$

$$I_{diff} = K_1 \cdot I_{bias}$$

Characteristic equation for the range: $I_{bias} \ge I_{s2}$

$$I_{diff} = K_1 \cdot I_{s2} + K_2 (I_{bias} - I_{s2})$$

K_1: gradient of characteristic in range $\frac{I_{s1}}{K_1} \le I_{bias} \le I_{s2}$

K_2: gradient of characteristic in range $I_{bias} \ge I_{s2}$

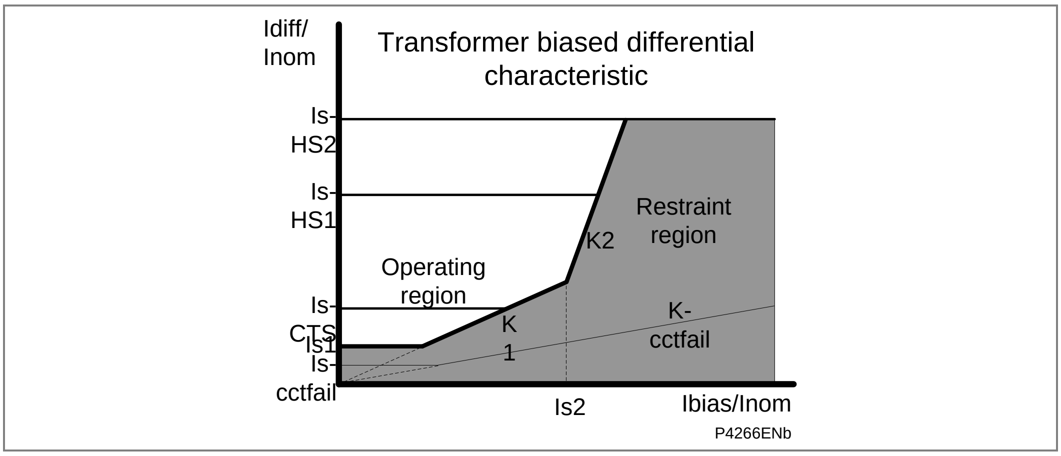


Figure 13 - Tripping characteristic of differential protection

1.3.5 High-Set Differential Protection Function

The high set 1 algorithm uses a peak detection method to achieve fast operating times. The peak value is the largest absolute value in the latest 24 samples (latest cycle). Since the high set 1 algorithm uses a peak detection method, **Is-HS1** is set above the expected highest magnetizing inrush peak to maintain immunity to magnetizing inrush conditions.

To declare high set 1 trip, two conditions must be fulfilled:

- The peak value of the differential current is greater than **Is-HS1** setting
- The bias characteristic is in the operating region

Above the adjustable threshold **Is-HS1** of the differential current, the relay will trip without taking into account either the second harmonic blocking or the overfluxing blocking, but the bias current is considered. The high set 1 resets when the differential and bias currents are in the restraint area.

The high set 2 algorithm uses Fourier quantities. If the differential current exceeds the adjustable threshold **Is-HS2**, the bias current, the second harmonic and overfluxing restraints are no longer taken into account. As a result, the relay issues a high set 2 trip regardless of the harmonic blocking or biased current. The high set 2 element resets when the differential current drops below 0.95*Is-HS2.

1.3.6 Low-Set Differential Protection Function

Transient bias is added for through fault stability. The transient bias is on a per-phase basis and is not affected by K1 or K2 settings.

Once the differential and bias currents are calculated, the following comparisons are made and an operate/restrained signal is obtained:

Flat slope: $I_{bias,\max} \le \frac{I_{s1}}{K_1}$

$I_{diff} \ge I_{s1}$

K1 slope: $\frac{I_{s1}}{K_1} \le I_{bias,\max} \le I_{s2}$

$I_{diff} \ge K_1 \cdot I_{bias.\max} + Transient \quad Bias$

K2 slope: $I_{s2} \le I_{bias,\max}$

$$I_{diff} \geq K1 \cdot I_{s2} + K2 \cdot \left(I_{bias.\max} - I_{s2}\right) + Transient \quad Bias$$

A count strategy is used so that the protection operates slower near the boundary of operation. This approach is used to stabilize the relay under some marginal transient conditions. The protection trips on a count of 2, which is approximately 5 ms after fault detection. The count is increased to 4 if the differential current is within 0.5*Is1 of the threshold.

1.3.7 Magnetizing Inrush Current Blocking

The phenomenon of magnetizing inrush is a transient condition which occurs primarily when a transformer is energized. It is not a fault condition, and therefore does not require the operation of the protection, which, on the contrary must remain stable during the inrush transient.
Magnetizing inrush can occur under three conditions: initial, recover and sympathetic.

Initial Magnetization Inrush:

The initial magnetizing inrush may occur when energizing the transformer after a prior period of de-energization. This has the potential of producing the maximum magnetizing inrush.

The following diagram shows a transformer magnetizing characteristic. To minimize material costs, weight and size, transformers are generally operated near to the knee point of the magnetizing characteristic. Consequently, only a small increase in core flux above normal operating levels will result in a high magnetizing current.

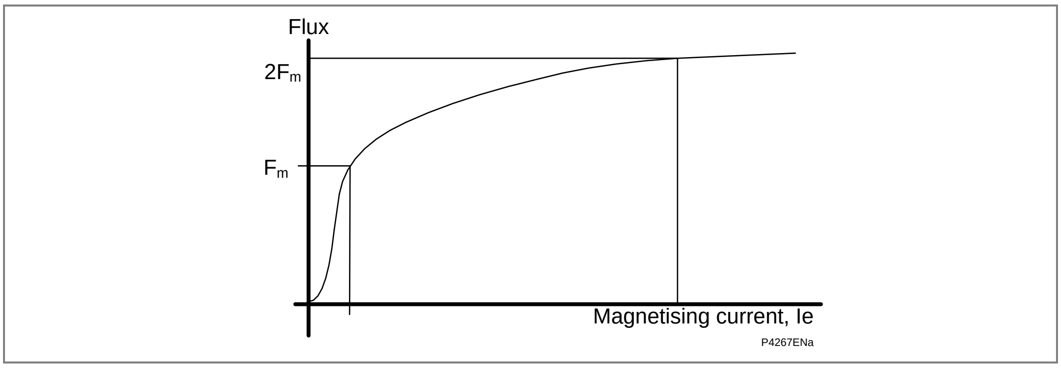


Figure 14 - Transformer magnetizing characteristic

Under normal steady state conditions, the magnetizing current associated with the operating flux level is relatively small (2-5% of full load current). However, if a transformer winding is energized at a voltage zero, with no remnant flux, the flux level during the first voltage cycle (2 x normal max flux) will result in core saturation and in a high, non-sinusoidal magnetizing current waveform. This current is commonly referred to as magnetizing inrush current and may persist for several cycles. The maximum initial-magnetizing current may be as high as 8-30 times the full-load current. Resistance in the supply circuit and transformer and the stray losses in the transformer reduce the peaks of the inrush current such that it decays to the normal exciting current value. The time constant varies from 10 cycles to as long as 1 minute in very high inductive circuits. The following diagram shows the magnetizing inrush phenomenon.

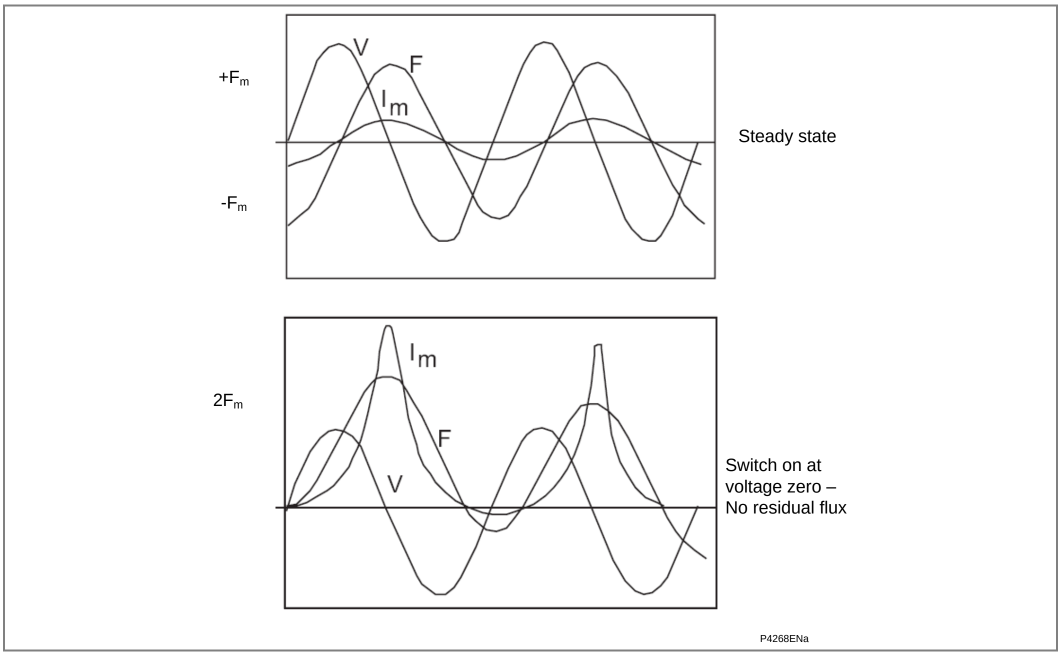


Figure 15 - Magnetizing inrush phenomenon

The magnitude and duration of magnetizing inrush current waveforms are dependant on a number of factors such as transformer design, size, system fault level, point on wave of switching, number of banked transformers etc.

Some inrush will always occur in one or two phases and generally all three phases in a three phase circuit. The following diagram indicates typical magnetizing inrush wave forms as seen by the differential protection.

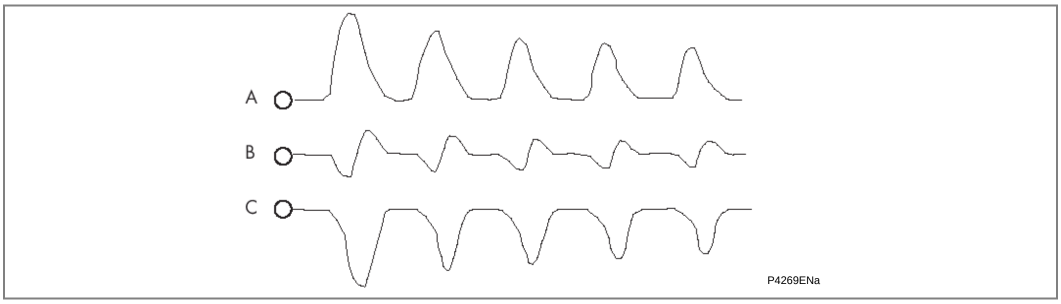


Figure 16 - Magnetizing inrush current waveforms

Recovery magnetizing inrush:

> As stated in IEEE Std. C37.91-2000, magnetizing inrush can be caused by any abrupt change of magnetizing voltage. These include the occurrence of a fault, the removal of the fault, change of character of a fault (a single phase fault evolving to two phase fault). The recovery inrush is when the voltage returns back to normal. The worst case of recovery inrush occurs after a solid three phase external fault near a transformer bank is removed and the voltage gets back to normal.

Sympathetic magnetizing inrush:

> According to IEEE Std. C37.91-2000, a severe magnetizing inrush may occur when energizing a transformer at a station at which at least one other transformer is already energized. This inrush will involve transformers that are already energized as well as transformers being energized. This inrush transient may be particularly long in duration. The inrush into the transformer being energized occurs during the opposite half-cycle to that of the already energized transformer. Therefore, the net inrush into all transformers may approximate a sine wave of fundamental frequency, and therefore not operate the second harmonic blocking unit of the differential relay if it is protecting both parallel transformers.

As described above, when an unloaded transformer is energized, the inrush current at unfavorable points on wave such as for voltage zero may have values that exceed the transformer nominal current several times over. Since the high inrush current flows on the connected side only, the tripping characteristic of differential protection may give rise to a trip unless stabilizing action is taken. The fact that the inrush current has a high proportion of second harmonics offers a possibility of stabilization against tripping by the inrush current.

The MiCOM relay filters the differential current. The fundamental I_{diff}(fn) and second harmonic components I_{diff}(2*fn) of the differential current are determined. Second harmonic blocking is phase segregated. If the ratio I_{diff}(2*fn)/I_{diff}(fn) exceeds a specific adjustable value in at least one phase in two consecutive calculations, and if the differential current is larger than 0.1 pu (minimum setting of Is1), tripping is blocked optionally in one of the following modes:

- Across all three phases
- Selectively for one phase

There will be no blocking if the differential current exceeds the set thresholds **Is-HS1** or **Is-HS2**.

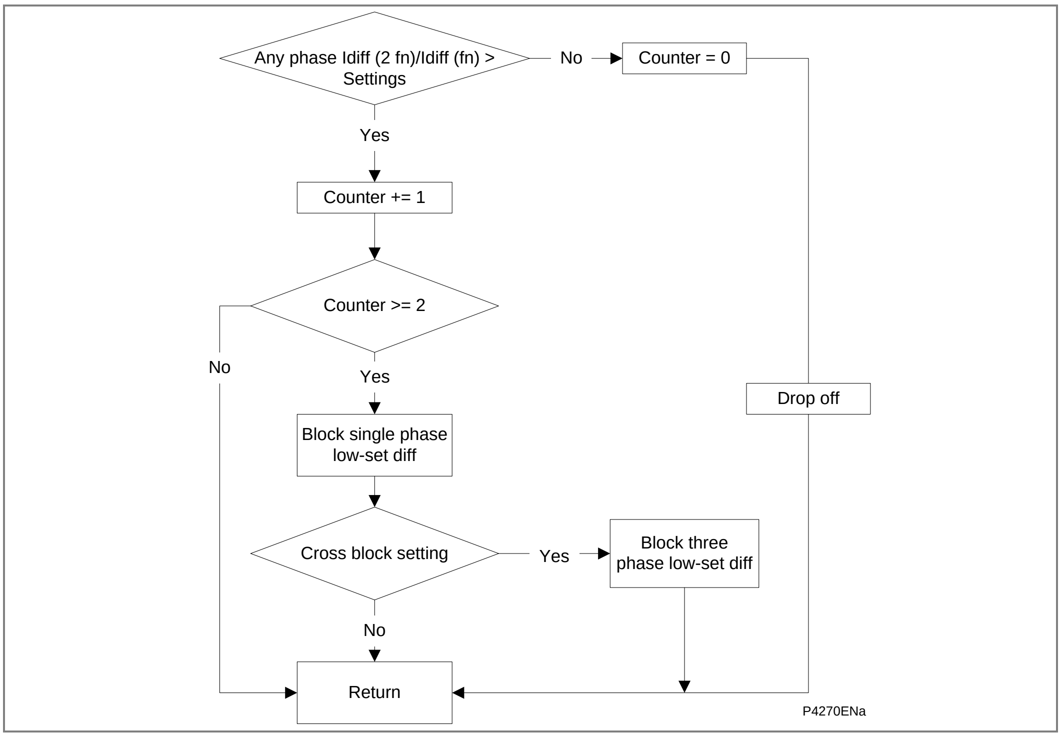


Figure 17 - Inrush stabilization (second harmonic blocking)

1.3.8 Overfluxing Restraint

If the transformer is loaded with a voltage in excess of the nominal voltage, saturation effects occur. Without stabilization, these could lead to differential protection tripping. The fact that the current of the protected object under saturation conditions has a high proportion of fifth harmonic serves as the basis of stabilization.

The MiCOM relay filters the differential current and determines the fundamental component I_{diff}(fn) and the fifth harmonic component I_{diff}(5·fn). If the ratio I_{diff}(5·fn)/I_{diff}(fn) exceeds the set value Ih(5)%> in at least one phase in two consecutive calculations, and if the differential current is larger than 0.1 pu (minimum setting of Is1), tripping is blocked selectively for one phase.

To add some security, the 5th harmonic/fundamental ratio is ‘AND’ gated with the condition that the bias current in that phase is below the bias characteristic knee point setting Is2 (effectively confirming a load condition).

There will be no blocking if the differential current exceeds the set thresholds **Is-HS1** or **Is-HS2**.

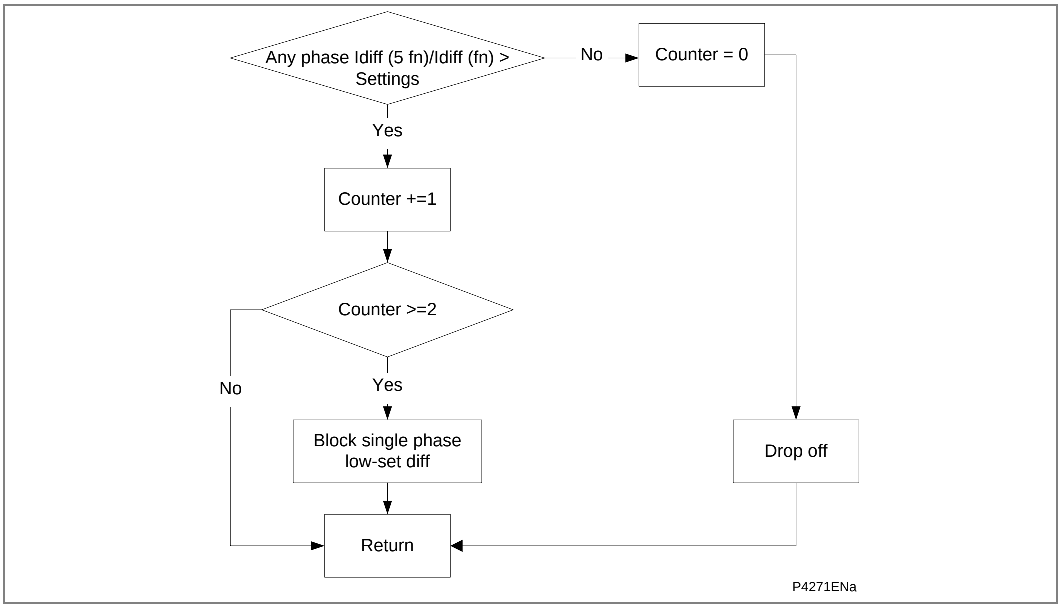


Figure 18 - Overfluxing restraint

The following logic diagram shows the inhibiting of the differential algorithm by magnetizing inrush or overfluxing conditions:

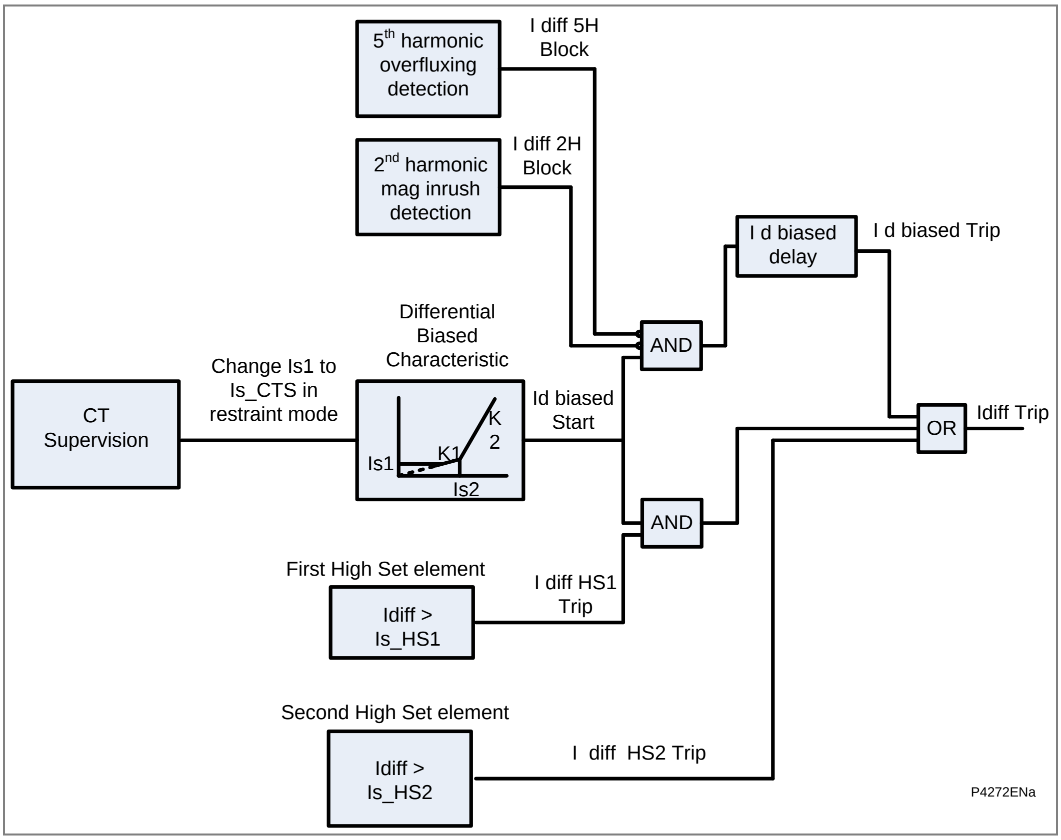


Figure 19 - Differential protection

1.4 NPS Overpower (32 NP)

For the interturn interlocking logic a single stage negative phase sequence apparent overpower element S2>1 is provided. The element has a start output and a time-delayed trip output.

The NPS apparent power is calculated as follows:

S2 = V2 x I2 (magnitude calculation only)

DDB signals are available to indicate the start and trip of the NPS apparent power protection, (Start: DDB 1139, Trip: DDB 881). 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.

The negative sequence overpower protection start is mapped internally to the ANY START DDB signal – DDB 992.

The NPS overpower operation is shown in the following logic diagram.

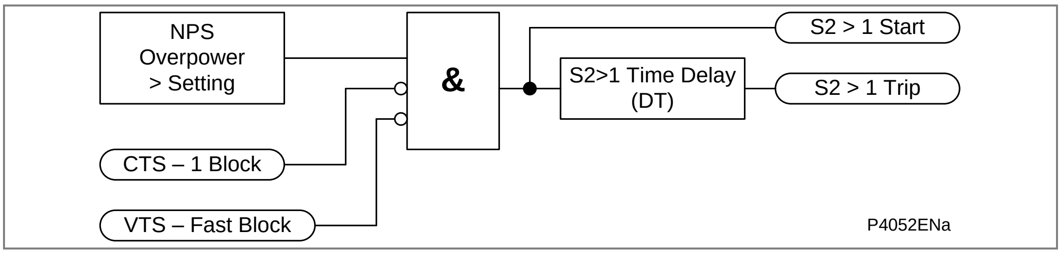


Figure 20 - NPS overpower logic diagram

1.5 Overcurrent Protection (50/51)

The overcurrent protection included in the relay 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 3 phase current source can be selected using the **I> CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2** setting.

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 or **IEEE curves**

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

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

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)

IDMT 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

Table 5 - Inverse time curves

Note	*The IEEE, US curves and User 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/User 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.*

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

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

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 6 - Reset curves

1.5.1 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 (i.e. Earth Fault 1 and Earth Fault 2 where available) protections. The curve is represented by the following equation (where t is in seconds and K is adjustable from 0.1 to 10 in steps of 0.05).

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

1.5.2 Timer Hold Facility

The first two stages of overcurrent protection in the 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 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.

If an IEC inverse or DT operating characteristic is chosen, this time delay is set via the **I>1/2 tRESET** setting.
If an IEEE/US operate curve is selected, the reset characteristic may be set to either definite time or inverse time as selected in cell **I>1/2 Reset Char**.
If definite time (**DT**) is selected the **I>1/2 tRESET** cell may be used to set the time delay.
If inverse time reset ('Inverse') is selected the reset time will follow the inverse time operating characteristic, modified by the time dial setting, selected for **I>1/2 Function**.

The functional logic diagram for non-directional overcurrent is shown in the *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.

DDB signals are also available to indicate the start and trip of each phase of each stage of protection, (Starts: DDB 1040-1055, Trips: DDB 800-815). 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.

Overcurrent protection starts 1/2/3/4 are mapped internally to the ANY START DDB signal – DDB 992.

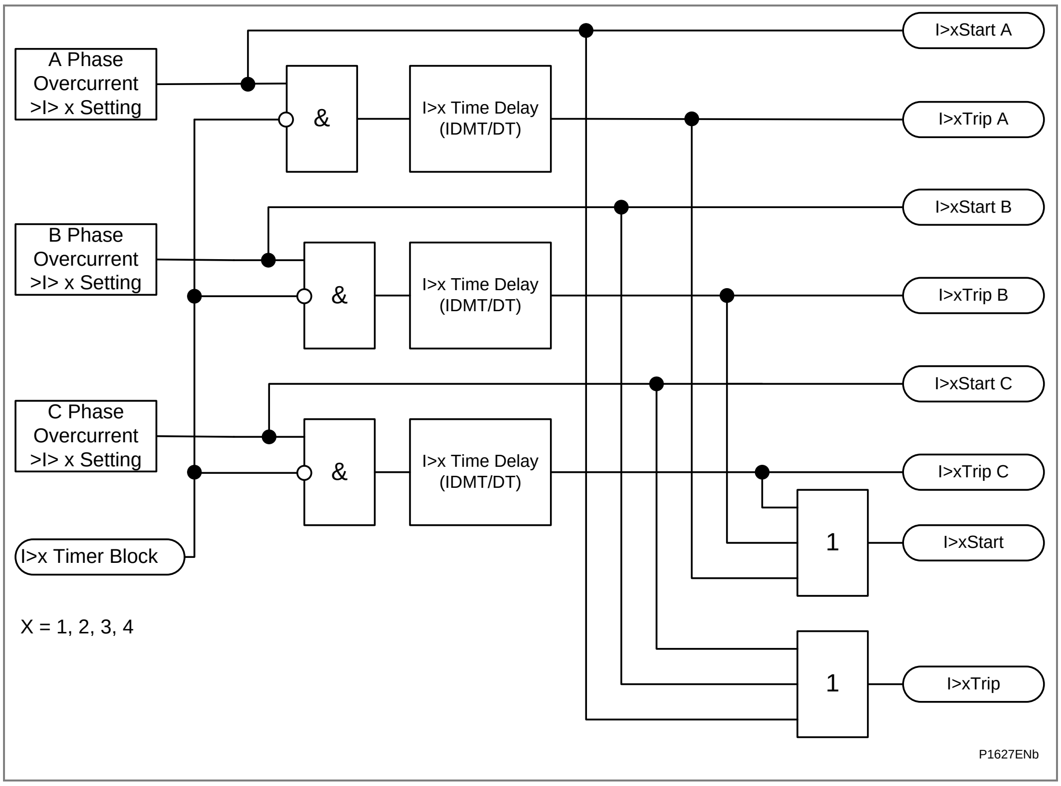


Figure 21 - Non-directional overcurrent logic diagram

1.6 Directional Overcurrent Protection (67)

The phase fault elements of the MiCOM P44y/P445/P54x/P841 relays are internally polarized by the quadrature phase-phase voltages, as shown in following *Phase, Operating Current and Polarizing Voltages* table.

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

Table 7 - 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 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 the following *Directional overcurrent logic* diagram.

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° < (angle(I) - angle(V) - RCA) < 90°

Directional reverse -90° > (angle(I) - angle(V) - RCA) > 90°

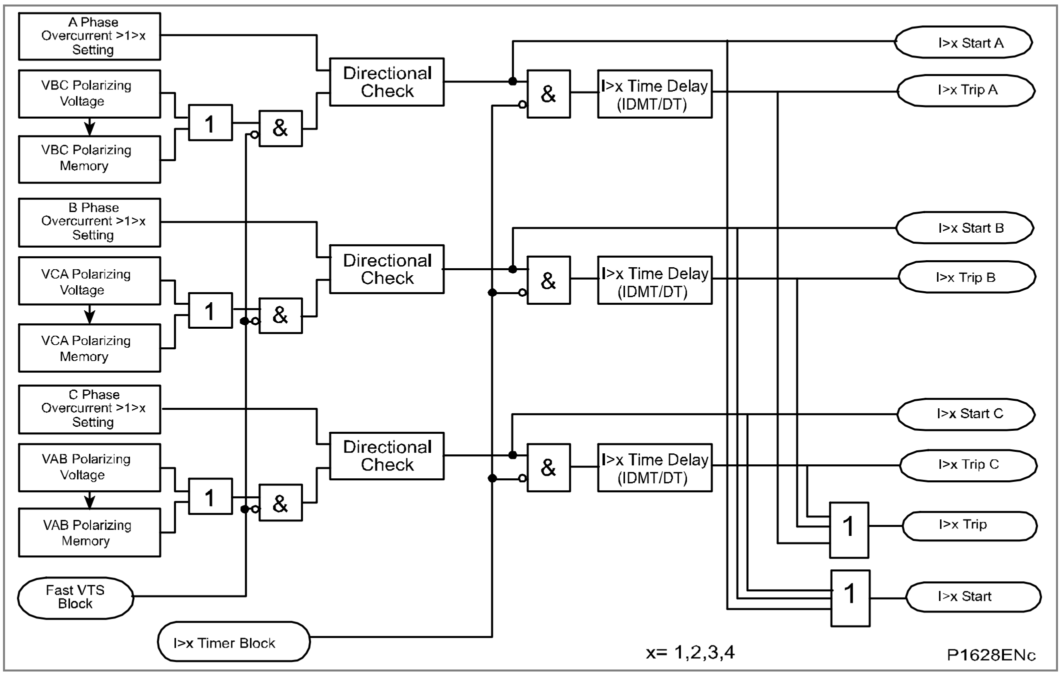


Figure 22 - Directional overcurrent logic

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 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.

1.6.1 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 MiCOM 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.

1.7 Negative Phase Sequence (NPS) Overcurrent Protection (46OC)

The relay provides four independent stages of Negative Phase Sequence (NPS) overcurrent protection.

Each stage has a current pick up setting **I2>n Current Set**, and is time delayed in operation by the adjustable timer **I2>n Time Delay**. 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 NPS directional elements to operate, the relay must detect a polarizing voltage above a minimum threshold, **I2> V2pol Set**. The 3 phase current source can be selected using the **I2> CT Source – IA-1/IB-1/IC-1** or **IA-2/IB-2/IC-2** setting.

When the element is selected as directional, a VTS Block option is available. When the relevant bit 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.

The NPS overcurrent element has a current pick up setting **I2>x Current Set**, and is time delayed in operation by an adjustable timer **I2>x Time Delay**. The user may choose to directionalize operation of the element, for either forward or reverse fault protection for which a suitable relay characteristic angle may be set. Alternatively, the element may be set as non-directional.

A timer block input is available for each stage which will reset the NPS overcurrent timers of the relevant stage if energized, (DDB 583-586). All 4 stages can be blocked by energizing the inhibit DDB signal via the PSL (I2> Inhibit: DDB 582). DDB signals are also available to indicate the start and trip of each stage of protection, (Starts: DDB 1064-1067, Trips: DDB 824-827).

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.

NPS overcurrent protection starts 1/2/3/4 are mapped internally to the ANY START DDB signal – DDB 992.

The non-directional and directional operation is shown in these diagrams:

- Negative sequence overcurrent non-directional operation
- Directionalizing the negative phase sequence overcurrent element

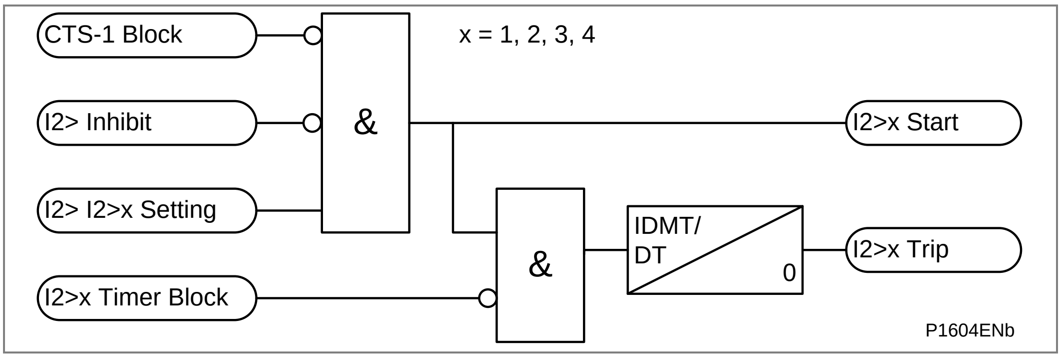


Figure 23 - Negative sequence overcurrent non-directional operation

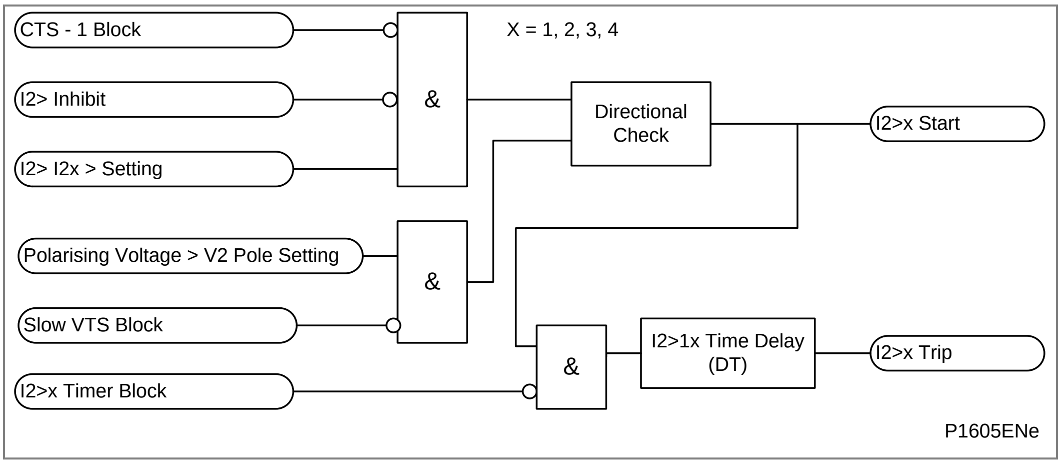


Figure 24 - Directionalizing the negative phase sequence overcurrent element

Directionality is achieved by comparison of the angle between NPS voltage and the NPS 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 NPS 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 NPS voltage. This may be determined during the commissioning stage by viewing the NPS measurements in the relay.

1.8 System Back-Up Protection (51V/21)

A single protection element that can be configured as either voltage dependant overcurrent or under impedance is provided in the relay for system back-up protection. The operation of the element is described in the following sections.

The function operates from the phase currents measured by the IA, IB and IC measurement inputs on the relay.

A timer block input is available for the voltage dependent overcurrent and underimpedance System Backup protection elements which will reset the timers of the relevant elements if energized, (VDepOC Timer Block, DDB 608 and UnderZ Timer Block, DDB 609). DDB signals are also available to indicate a three-phase and per phase start and trip, (Voltage dependent overcurrent Starts: DDB 1127-1130, Voltage dependent overcurrent Trips: DDB 868-871, Underimpedance Starts: DDB 1131-1138, Underimpedance Trips: DDB 872-879). 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.

The protection starts for each element are mapped internally to the ANY START DDB signal – DDB 992.

1.8.1 Voltage Dependant Overcurrent Protection

The generator terminal voltage will drop during fault conditions and so a voltage measuring element can be used to control the current setting of this element. On detection of a fault the current setting is reduced by a factor K. This ensures faults are cleared in spite of the presence of the generator decrement characteristic. Line voltages are used to control each phase overcurrent element as shown in this table.

Phase current	Control voltage
Ia	Vab
Ib	Vbc
Ic	Vca

Table 8 - Voltages used for Phase Overcurrent elements

A single stage, non-directional overcurrent element is provided. The element has a time delayed characteristic that can be set as either Inverse Definite Minimum Time (IDMT) or Definite Time (DT). The element can be selectively enabled or disabled and can be blocked via a relay input so that the element can be integrated into a blocked overcurrent protection scheme.

The element can be fed from CTs at the terminal or neutral end of the generator.

If voltage dependant overcurrent operation is selected, the element can be set in one of two modes, voltage controlled overcurrent or voltage restrained overcurrent.

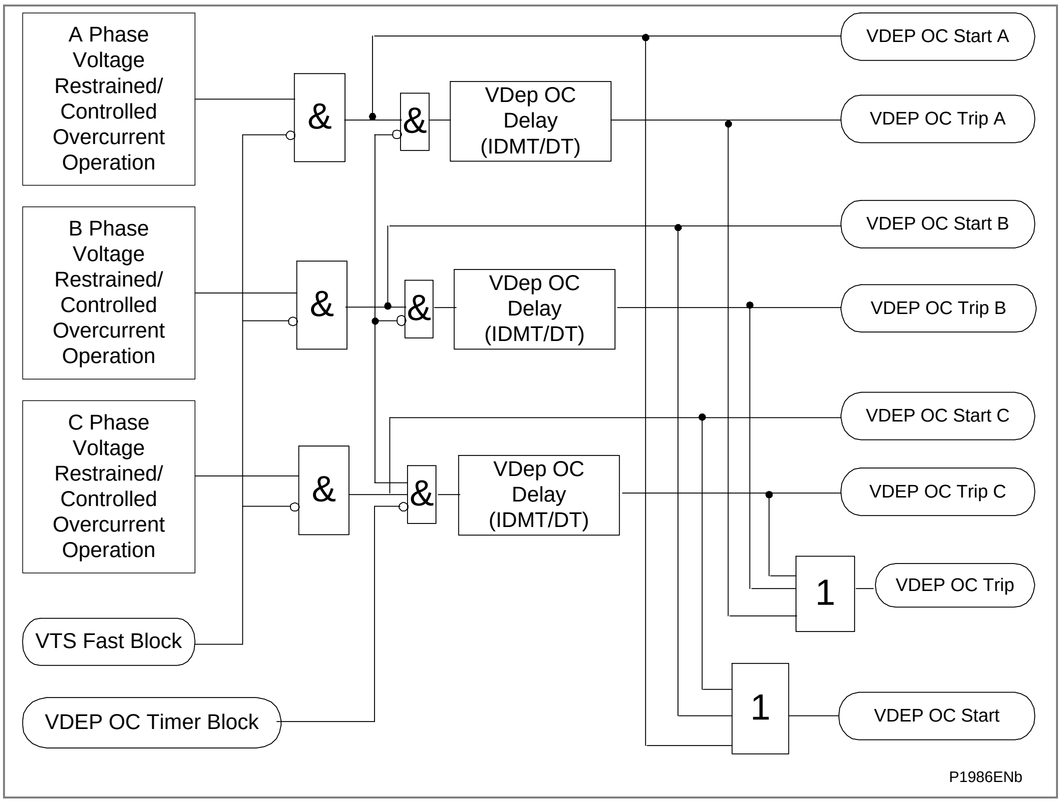


Figure 25 - Voltage restrained / controlled overcurrent logic diagram

1.8.1.1 Voltage Controlled Overcurrent Protection

In this mode of operation, the under voltage detector is used to produce a step change in the relay current setting (from **V Dep OC I> Set** to **V Dep OC k Set** x **V Dep OC I> Set**), when voltage falls below the voltage setting, **V Dep OC V<1 Set**. Under load conditions the relay can have a high current setting greater than full load current. Under fault conditions the relay is switched to a more sensitive setting leading to fast fault clearance. The operating characteristic of the current setting when voltage controlled mode is selected is shown in in this diagram:

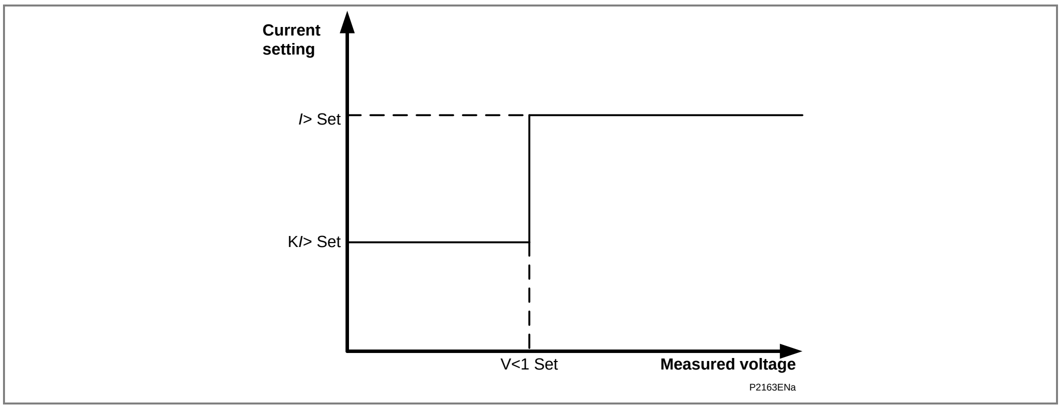


Figure 26 - Current pickup level for voltage controlled overcurrent protection

Where the generator is directly connected to a busbar, voltage controlled overcurrent protection may be preferred.

The voltage controlled overcurrent protection is provided with a timer hold facility. Setting the hold timer to a value other than zero delays the resetting of the protection element timers for this period.

If an IEC inverse or DT operating characteristic is chosen, this hold time delay is set via the **V Dep OC tRESET** setting.

If an IEEE/US operate curve is selected, the reset characteristic may be set to either definite time or inverse time as selected in cell **V Dep OC Reset Char**. If definite time (**DT**) is selected the **V Dep OC tRESET** cell may be used to set the time delay, as above. If inverse time reset (**Inverse**) is selected the reset time will follow the inverse time operating characteristic, modified by the time dial setting, selected for **V Dep OC Function**.

1.8.1.2 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 voltage-restrained current setting is related to measured voltage as follows:

For V > Vs1: Current setting (I_S) = **I>**
For Vs2 < V < Vs1: Current setting (I_S) = K.**I>** + (**I >** - K. **I>**) {V – V<2 / V<1 – V<2}
For V < Vs2: Current setting (I_S) = K.**I>**

Where:

I>	=	V Dep. OC V<1 Set
I_S	=	Current setting at voltage V
V	=	Voltage applied to relay element
Vs1	=	“V Dep. OC V<1 Set”
Vs2	=	“V Dep. OC V<2 Set”

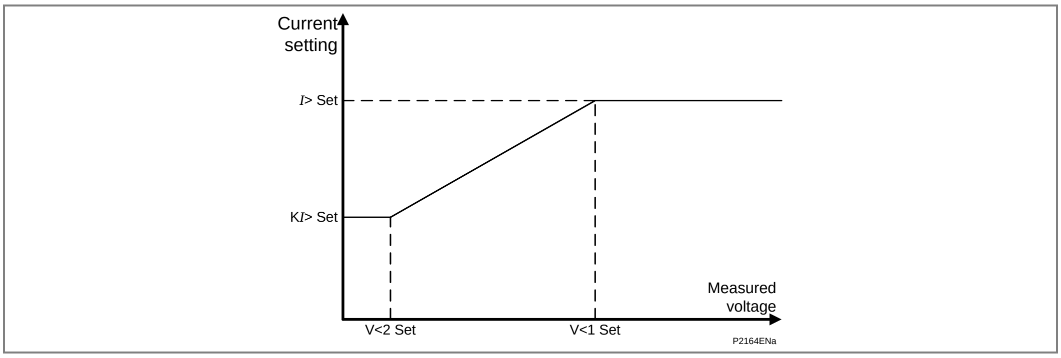


Figure 27 - Current pickup level for voltage restrained overcurrent protection

The voltage restrained overcurrent protection is provided with a timer hold facility. Setting the hold timer to a value other than zero, delays the resetting of the protection element timers for this period.

If an IEC inverse or DT operating characteristic is chosen, this hold time delay is set via the **V Dep OC tRESET** setting.

If an IEEE/US operate curve is selected, the reset characteristic may be set to either definite time or inverse time as selected in cell **V Dep OC Reset Char**. If definite time (DT) is selected the **V Dep OC tRESET** cell may be used to set the time delay, as above. If inverse time reset (**Inverse**) is selected the reset time will follow the inverse time operating characteristic, modified by the time dial setting, selected for **V Dep OC Function**.

1.8.1.3 Under Impedance Protection

When the element is set to under impedance mode the element operates with a time delayed three-phase non-directional impedance characteristic, shown in the following diagram.

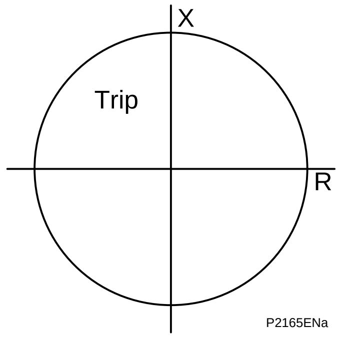


Figure 28 - Under impedance element tripping characteristic

Impedance for each phase is calculated as shown:

$$Za = \frac{Vab}{Ia} \quad Zb = \frac{Vbc}{Ib} \quad Zc = \frac{Vca}{Ic}$$

With rated voltage applied, the element operates as a definite time overcurrent relay. It operates at a lower current as the voltage reduces, hence the element is similar to a voltage restrained overcurrent element, operating with a definite time characteristic.

The under impedance protection is provided with a timer hold facility. Setting the hold timer, **Z< tRESET**, to a value other than zero, delays the resetting of the protection element timer for this period.

The minimum phase current and the line voltage required for the P342/P343/P344/P345 under impedance protection to work is
20 mA and 2 V (In = 1 A, Vn = 100/120 V) and
100 mA and 8 V (In = 5 A, Vn = 380/480 V).

Note	*Under impedance consists of separate three-phase elements and the checking is done on a per phase basis that is the inhibition of one phase will not affect the other phases.*

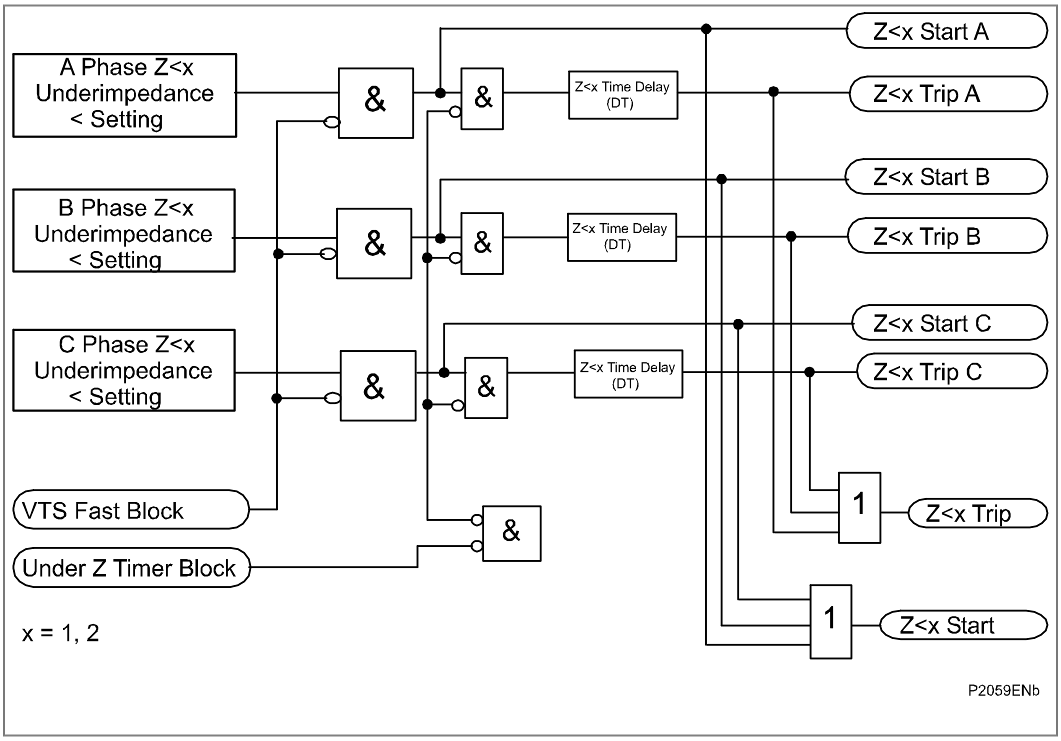


Figure 29 - Under impedance logic diagram

1.9 Undervoltage Protection (27)

Both the under and overvoltage protection functions can be found in the relay menu **Volt Protection**. The undervoltage protection included within the 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.

Note	*If the undervoltage protection is set for phase-phase operation then the DDB signals V<1/2 Start/Trip A/AB, V<1/2 Start/Trip B/BC, V<1/2 Start/ Trip C/CA refer to V<1/2 Start/Trip AB and V<1/2 Start/Trip BC and V<1/2 Start/Trip CA. If set for phase-neutral then the DDB signals V<1/2 Start/Trip A/AB, V<1/2 Start/Trip B/BC, V<1/2 Start/Trip C/CA refer to V<1/2 Start/Trip A and V<1/2 Start/Trip B and V<1/2 Start/Trip C.*

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)

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 the *Undervoltage - single and three phase tripping mode (single stage)* diagram below:

Each stage of undervoltage protection can be blocked by energizing the relevant DDB signal via the PSL, (DDB 601, DDB 602). DDB signals are also available to indicate a three-phase and per phase start and trip, (Starts: DDB 1103-1110, Trips: DDB 847-854).

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.

Undervoltage protection starts are mapped internally to the ANY START DDB signal – DDB 992.

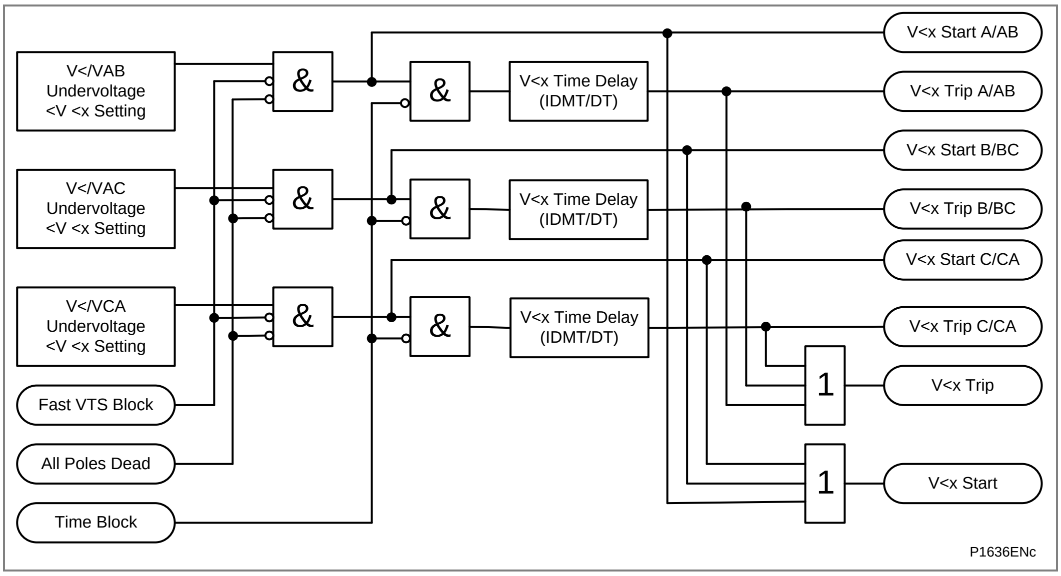


Figure 30 - Undervoltage - single and three phase tripping mode (single stage)

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.

1.10 Overvoltage Protection (59)

Both the under and overvoltage protection functions can be found in the relay menu **Volt Protection**. The overvoltage protection included within the 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.

Note	*If the overvoltage protection is set for phase-phase operation then the DDB signals V>1/2 Start/Trip A/AB, V>1/2 Start/Trip B/BC, V>1/2 Start/Trip C/CA refer to V>1/2 Start/Trip AB and V>1/2 Start/Trip BC and V>1/2 Start/Trip CA. If set for phase-neutral then the DDB signals V>1/2 Start/Trip A/AB, V>1/2 Start/Trip B/BC, V>1/2 Start/Trip C/CA refer to V>1/2 Start/Trip A and V>1/2 Start/Trip B and V>1/2 Start/Trip C.*

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 this formula:

$$t = K/(M-1)$$

Where:

K = Time Multiplier Setting (TMS)
t = Operating Time in seconds
M = Measured voltage / relay setting voltage (V> Voltage Set)

A timer block input is available for each stage which will reset the undervoltage timers of the relevant stage if energized, (DDB 598, DDB 599). DDB signals are also available to indicate a three-phase and per phase start and trip, (Starts: DDB 1094-1101, Trips: DDB 838-845). 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.

Overvoltage protection starts are mapped internally to the ANY START DDB signal – DDB 992.

The logic diagram of the first stage overvoltage function is shown in this diagram.

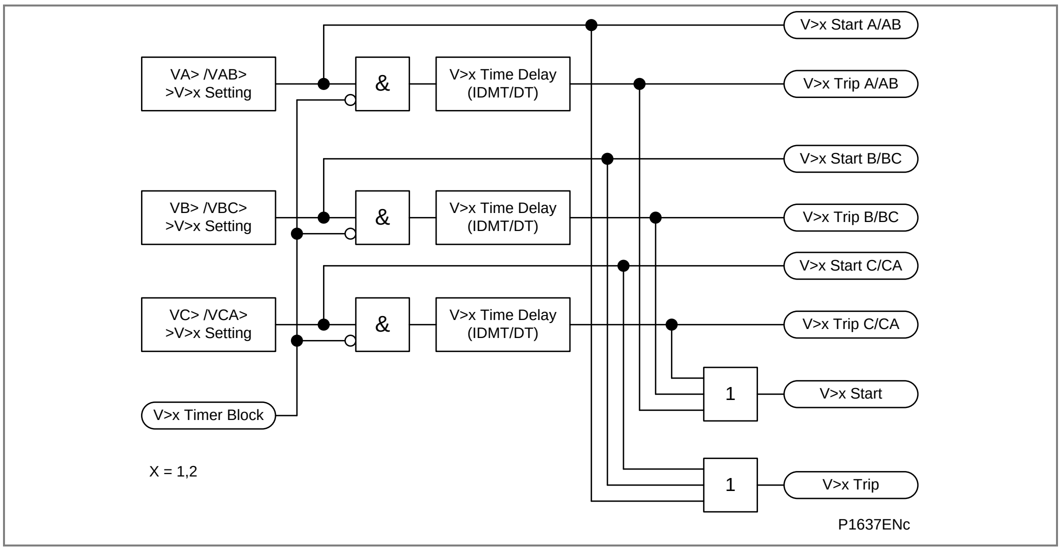


Figure 31 - Overvoltage - single and three phase tripping mode (single stage)

1.11 Negative Phase Sequence (NPS) Overvoltage Protection (47)

The relay includes a Negative Phase Sequence (NPS) overvoltage element. This element monitors the input voltage rotation and magnitude (normally from a bus connected voltage transformer) and may be interlocked with the generator circuit breaker to prevent the machine from being energized whilst incorrect phase rotation exists.

This single stage is selectable as definite time only and is enabled in the **V2>status** cell.

The logic diagram for the negative sequence overvoltage protection is shown in this diagram:

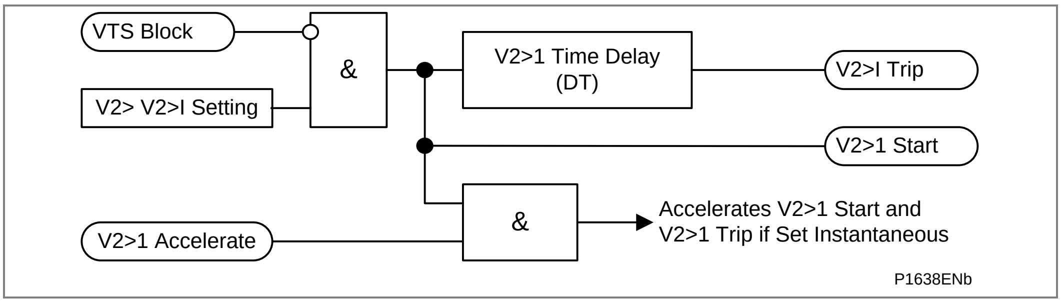


Figure 32 - Negative sequence overvoltage element logic

DDB signals are available to indicate a start and a trip, (Start: DDB 1102, Trip: DDB 846). There is also a signal to accelerate the NPS overvoltage protection start (V2>1 Accelerate: DDB 600) which accelerates the operating time of the function from typically 80 ms to 40 ms when set to instantaneous.

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.

The NPS overvoltage protection start is mapped internally to the ANY START DDB signal – DDB 992.

1.12 Frequency Protection (81U/81O)

The P34x/P391/P445/P44y/P54x/P841 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 the following *Underfrequency logic (single stage)* diagram. Only a single stage is shown. The other three 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.

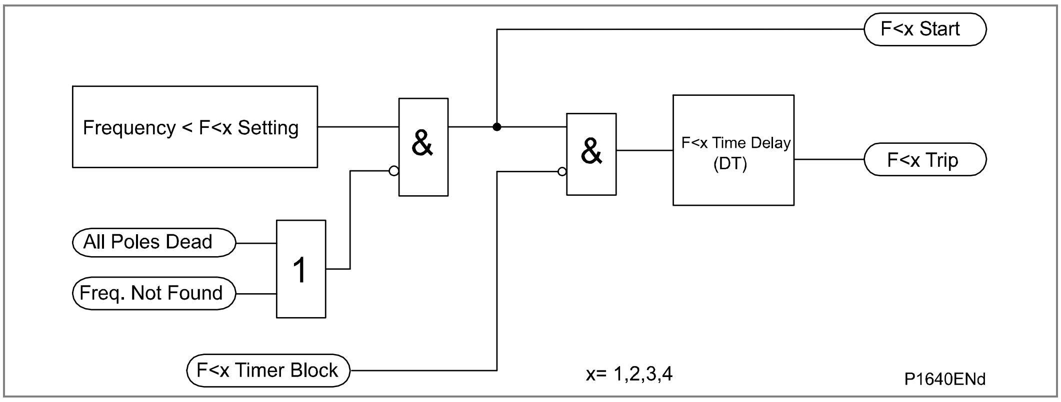


Figure 33 - Underfrequency logic (single stage)

The functional logic for the overfrequency function as shown in the *Overfrequency logic (single stage)* diagram. Only a single stage is shown as the other stages are functionally identical. 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.

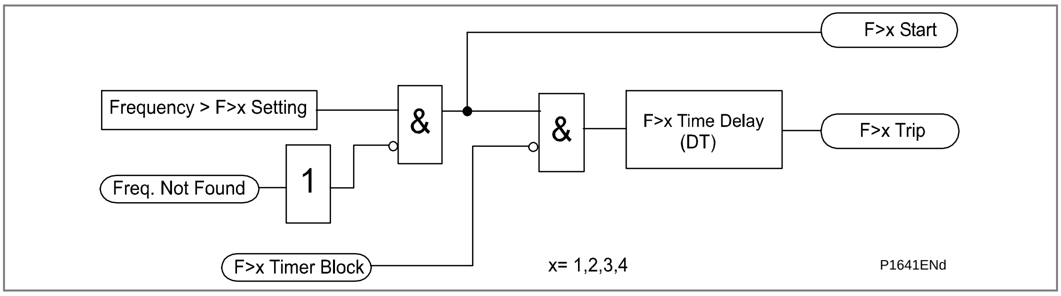


Figure 34 - Overfrequency logic (single stage)

A timer block input is available for each stage which will reset the under and overfrequency timers of the relevant stage if energized, (DDB 626-629, DDB 630-631). DDB signals are also available to indicate start and trip of each stage, (Starts: DDB 1172-1175, DDB 1176-1177, Trips: DDB 916-919, DDB 920-921).

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.

The under and overfrequency protection starts are mapped internally to the ANY START DDB signal – DDB 992.

1.13 Generator Turbine Abnormal Frequency Protection (81 AB)

Six bands of generator abnormal protection are provided within the relays. Each band has its own frequency limit settings and an individual accumulative time measurement. Operation within each of these bands is monitored and the time added to a cumulative timer, stored within the battery backed RAM. This ensures that on loss of auxiliary supply to the relay, the information is not lost. An individual dead band time delay setting is provided for each band. Within this dead band time delay, the frequency is allowed to stay inside the band without initiating the accumulative time measurement. This delay allows the blade's resonance during under frequency conditions to be established first, avoiding unnecessary accumulation of time. The delay therefore does not contribute to the accumulated time.

Note	*The dead band delay has no effect on the initiation of the start signals. Time accumulation will stop and all the start signals will be reset if the Frequency Not Found DDB 1068 is set.*

The amount of time spent in each band can be viewed in the **MEASUREMENTS 3** column in the relay. The maximum allowable time in each band is 1000 hours (3600000s), beyond which no more accumulation will be made. An individual reset cell is available in the **MEASUREMENTS 3** column in the relay for each accumulative time measurement to be independently reset to zero.

It is recommended the turbine abnormal frequency protection system be in-service whenever the unit is synchronized to the system, or while separated from the system but supplying auxiliary load. An inhibit signal is available to inhibit the time accumulation when the generator is off-line, that is the circuit breaker is open.

The trip output is latched and can only be reset if any of these conditions occur:

- The accumulative time is reset, or
- The corresponding band is disabled, or
- The entire abnormal frequency protection is disabled, or
- The Inhibit DDB 'Turbine F Inh' is energized.

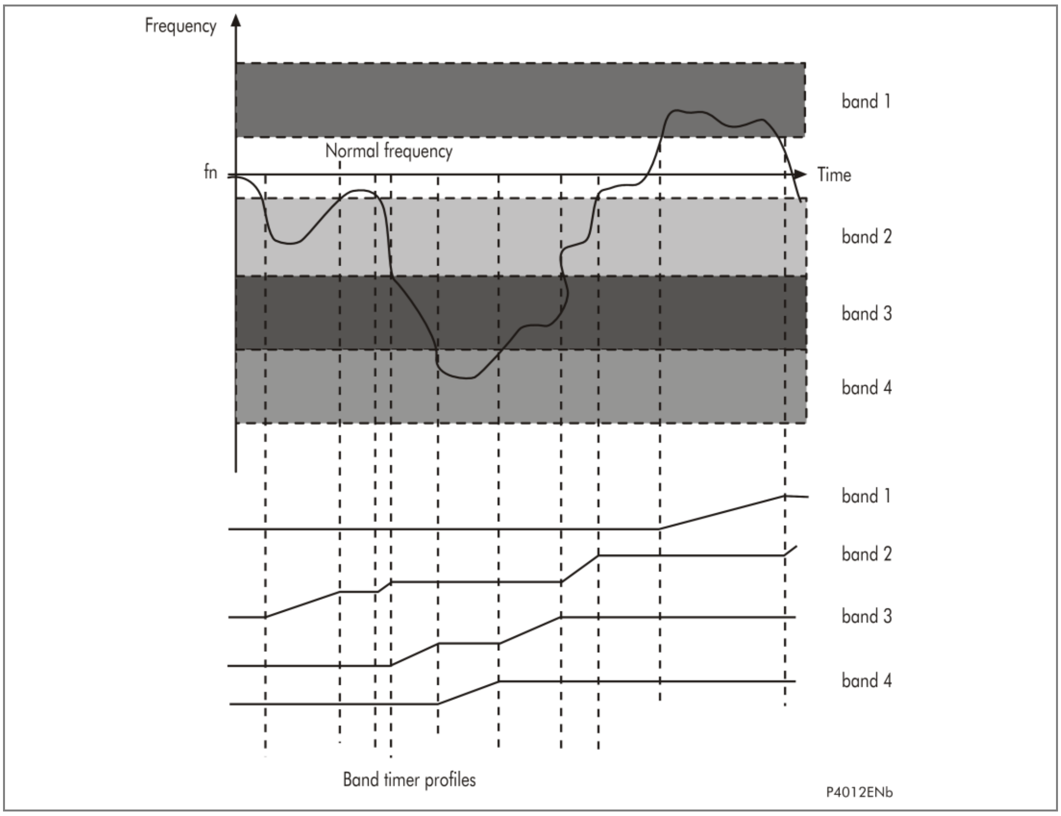


Figure 35 - Generator abnormal frequency protection

The above diagram shows the integrating timer behavior for abnormal frequency conditions over a long period of time. The timer for a particular band is incremented as long as the frequency is within the band lower and upper frequency settings. If two bands have overlapping frequency settings and the system frequency happens to be within both bands then the timers for both bands are incremented.

All frequency band stages can be inhibited by energizing a single DDB signal via the PSL (Turbine F Inh: DDB 632). DDB signals are also available to indicate the start and trip of each frequency band stage, (Starts: DDB 1178-1183, Trips: DDB 922-927).

Note	The start signals are instantaneous (i.e., without influence from the dead band delay timer) once the frequency is within the band.

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.

The frequency band starts are mapped internally to the ANY START DDB signal – DDB 992.

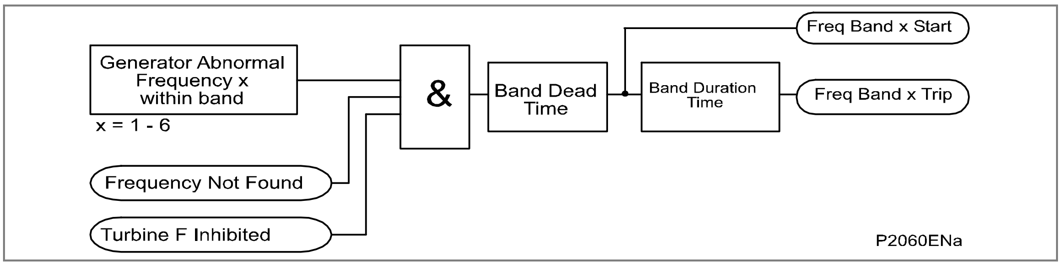


Figure 36 - Generator turbine abnormal frequency logic diagram

1.14 Field Failure Protection Function (40)

The field failure protection of the relay consists of two elements, an impedance element with two time delayed stages and a power factor alarm element, shown in the *Field failure protection characteristics* diagram.

The two stages of field failure protection in the relay are provided with a timer hold (drop off timer) facility, which may either be set to zero or to a definite time value. Setting of the timer to zero means that the field failure timer for that stage will reset instantaneously once the impedance falls outside 105% of the impedance characteristic. Setting of the hold timer to a value other than zero, delays the resetting of the protection element timers for this period. For an intermittent fault when the reset time (drop-off time) of the field failure protection 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 impedance pulses, for example during pole slipping, thereby reducing fault clearance times.

The timer hold (drop off timer) facility can be found for the two field failure stages as settings **FFail 1 DO Timer** and **FFail 2 DO Timer** respectively.

The elements operate from A phase current and A phase voltage signals measured by the I_A and V_A inputs on the relay. The minimum phase current and voltage required for P342/P343/P344/P345 field failure protection to work is 20 mA and 1 V (In = 1 A, Vn = 100/120 V) and 100 mA and 4 V (In = 5 A, Vn = 380/480 V).

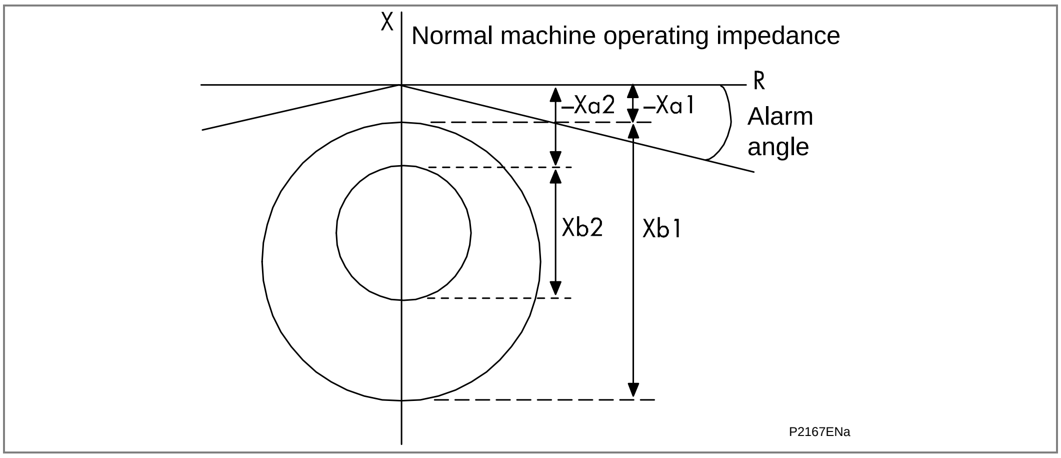


Figure 37 - Field failure protection characteristics

DDB signals are available to indicate the start and tripping of each stage (Starts: DDB 1120, DDB 1121, Trips: DDB 864, DDB 865). A further DDB 'Field Fail Alarm' signal is generated from the field failure alarm stage (DDB 373). 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.

The field failure protection starts are mapped internally to the ANY START DDB signal – DDB 992.

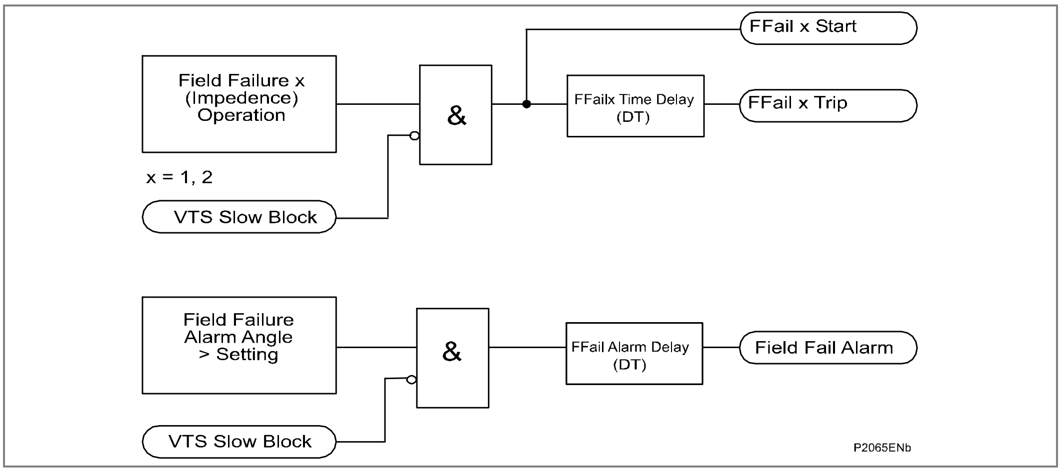


Figure 38 - Field failure logic diagram

1.15 Negative Phase Sequence Thermal Protection (46T)

The Negative Phase Sequence (NPS) protection provided by the relay is a true thermal replica with a definite-time alarm stage. The relay derives the negative phase sequence operating quantity from the following equation:

$$I_2 = \frac{I_a + a^2 I_b + aI_c}{3} \quad \text{where } a = 1.0 \angle 120°$$

Unbalanced loading results in the flow of positive and negative sequence current components.

Many traditional forms of generator NPS thermal protection relays have been designed with an extremely inverse (I_2^2t) operating time characteristic. Where the operating time of the characteristic is dependent solely on the instantaneous magnitude of negative phase sequence current present. This characteristic would be set to match the claimed generator thermal capacity. This is satisfactory when considering the effects of high values of negative phase sequence current.

For intermediate levels of NPS current, the rate of heating is slower. As a result, heat dissipation should be considered.

The basic expression of $t = K/I_{2cmr}$ does not cater for the effects of heat dissipation or for low standing levels of negative phase sequence current. The latter resulting in an increase in rotor temperature which remains within the machines design limits. An existing, tolerable, level of negative phase sequence current ($I_2<I_{2cmr}$), has the effect of reducing the time to reach the critical temperature level, if the negative phase sequence current level should increase beyond I_{2cmr}. The relays NPS thermal replica is designed to overcome these problems by modeling the effects of low standing levels of negative phase sequence currents.

The temperature rise in critical rotor components is related to the negative phase sequence current (I_2 per unit) and to time (t seconds) as follows. This assumes no preceding negative phase sequence current:

$$\theta°C \propto I_2^2 (1 - e^{-t/\tau})$$

Where:

$$\tau = \text{The thermal time constant, } \tau = K_g/I2_{CMR}^2$$

K_g is the generator's per-unit thermal capacity constant in seconds.

I_{2CMR} is the generator's per-unit continuous maximum I_2 rating.

The limiting continuous maximum temperature (θ_{CMR}) would be reached according to the following current-time relationship:

$$\theta°C = \theta_{CMR} \Rightarrow I_2^2 (1 - e^{-t/\tau}) = I_{2CMR}^2$$

From the above, the time for which a level of negative phase sequence current in excess of I_{2CMR} can be maintained is expressed as follows:

$$T = - (K_g / I_{2CMR}^2) \text{ loge } (1- (I_{2CMR} / I_2)*(I_{2CMR}/I_2))$$

The relays negative phase sequence element offers a true thermal characteristic according to the following formula:

$$t = \frac{(I2>2 \text{ k Setting})}{(I2>2 \text{ Current set})^2} \text{ Log}_e \left(1 - \left(\frac{(I2>2 \text{ Current set}}{I_2}\right)^2\right)$$

Note	*All current terms are in per-unit, based on the relay rated current, In.*

So, for an applied current of

I_2 = 5A = 1 In

I2>2 Current set = 0.25A = 0.05 In = 0.05 pu

I2>2 K Setting = 8.2 s

t = - I2>2 K Setting / (I2>2 Current Set)^2 loge (1- (I2>2 Current Set/I_2)^2)

t = -8.2/0.05^2 loge (1 - (0.05/1)^2) = 8.21 s

for I2 = 4A = 0.8 In = 0.8 pu

t = -8.2/0.05^2 loge (1 - (0.05/0.8)^2) = 12.84 s

The reset time is:

$$\text{treset} = \frac{(I2>2 \text{ k Setting})}{(I2>2 \text{ Current set})^2} \text{ Log}_e \left(1 - \frac{(-0.05)}{\left(\frac{I_2}{(I_2>2 \text{ Current set})^2 - 1}\right)}\right)$$

From the trip time of 8.21s the time to reset assuming I_2 =0 after tripping is:

treset = -8.2/0.05^2 loge (1 – (-0.05 / -1) = 168.16 s

When the protected generator sees a reduction in negative phase sequence current, metallic rotor components will decrease in temperature. The relay is provided with a separate thermal capacity setting (**I2>2 KRESET**), used when there is a reduction in I_2.

The negative sequence protection element will respond to system phase to earth and phase to phase faults. Therefore, the element must be set to grade with downstream earth and phase fault protections. To aid grading with downstream devices a definite minimum operating time for the operating characteristic can be set.
For levels of negative phase sequence current that are only slightly in excess of the thermal element pick-up setting, there will be a noticeable deviation between the relays negative phase sequence thermal protection current-time characteristic and that of the simple I_2^2t characteristic. For this reason, a maximum negative phase sequence protection trip time setting is provided. This maximum time setting also limits the tripping time of the negative phase sequence protection for levels of unbalance where there may be uncertainty about the machine's thermal withstand.

A time delayed negative sequence overcurrent alarm stage is provided to give the operator early warning of an unbalanced condition that may lead to generator tripping. This can allow corrective action to be taken to reduce the unbalance in the load.

The Negative Sequence element uses the current measured at the Ia, Ib, Ic inputs on the relay.

Thermal state of the machine can be viewed in the **NPS Thermal** cell in the **MEASUREMENTS 3** column. The thermal state can be reset by selecting **Yes** in the **Reset NPS Thermal** cell in **Measurements 3**. Alternatively the thermal state can be reset by energizing DDB 640 **Reset I2 Thermal** via the relay PSL.

A DDB signal is also available to indicate tripping of the element (DDB 944). A further DDB 'NPS Alarm' signal is generated from the NPS thermal alarm stage (DDB 370). The state of the DDB signal can be programmed to be viewed in the **Monitor Bit x** cells of the **COMMISSION TESTS** column in the relay.

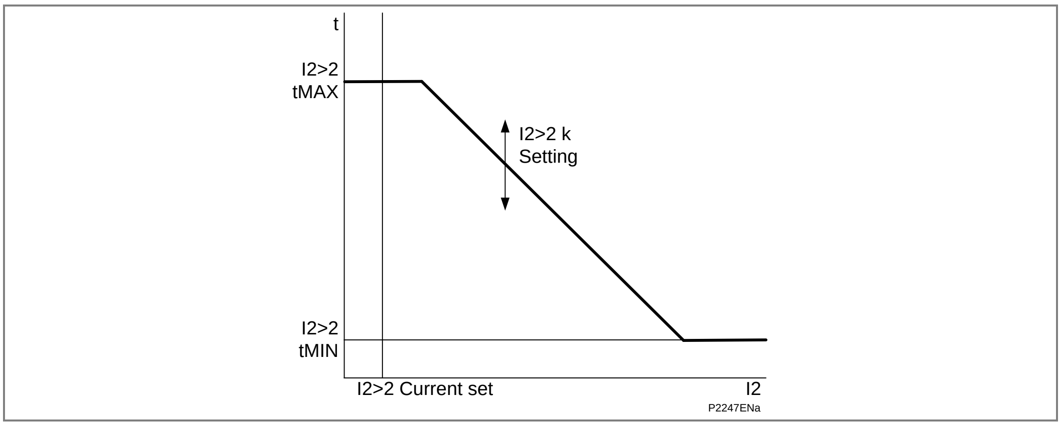


Figure 39 - Negative phase sequence thermal characteristic

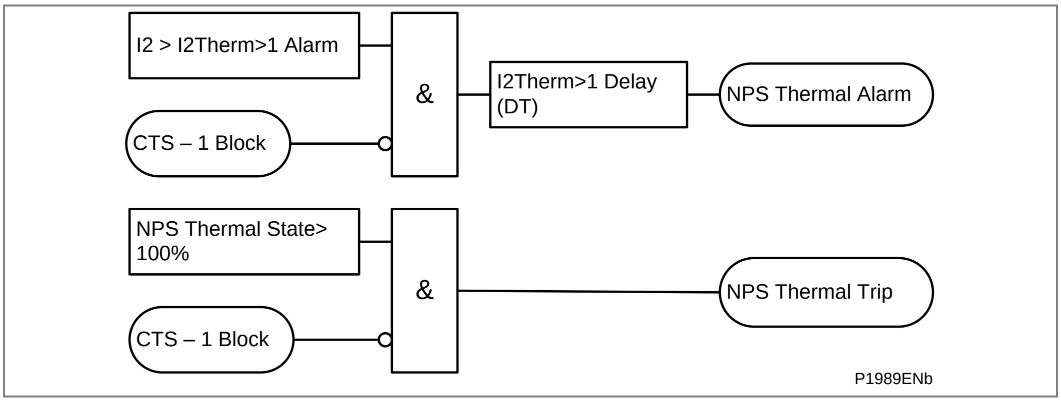


Figure 40 - NPS thermal logic diagram

1.16 Reverse Power/Overpower/Low Forward Power (32R/32O/32L)

The standard power protection elements of the relay calculate the three-phase active power based on the following formula, using the current measured at the Ia, Ib, Ic inputs on the relay.

$$P = V_aI_a \cos\phi a + V_bI_b \cos\phi b + V_cI_c \cos\phi c$$

Two stages of power protection are provided, these can be independently selected as either reverse power, over power, low forward power or disabled, and operation in each mode is described in the following sections. The power elements may be selectively disabled, via fixed logic, so that they can be inhibited when the protected machines CB is open, this will prevent mal-operation and nuisance flagging of any stage selected to operate as low forward power.

The relay is connected with the convention that the forward current is the current flowing from the generator to the busbar. This corresponds to positive values of the active power flowing in the forward direction. When a generator is operating in the motoring mode, the machine is consuming active power from the power system.

The motoring active power therefore flows in the reverse direction. The **Operating Mode** setting for the power protection allows the user to set the operating mode to either **Generating** or **Motoring**. If the mode is set to **Motoring**, the polarity of the calculated active power is inverted. The operating mode setting can be useful in applications involving pumped storage generators.

The two stages of power protection in the relay are provided with a timer hold (drop off timer) facility, which may either be set to zero or to a definite time value. Setting of the timer to zero means that the power timer for that stage will reset instantaneously once the current falls below 95% of the power setting. Setting of the hold timer to a value other than zero, delays the resetting of the protection element timers for this period. For an intermittent fault when the reset time (drop-off time) of the power protection 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 power pulses, thereby reducing fault clearance times. The timer hold (drop off timer) facility can be found for the two power stages as settings **Power 1 DO Timer** and **Power 2 DO Timer** respectively

DDB signals are available to indicate starting and tripping of each stage (Starts: DDB 1140, DDB 1141, Trips: DDB 882, 883). 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.

The power starts are mapped internally to the ANY START DDB signal – DDB 992.

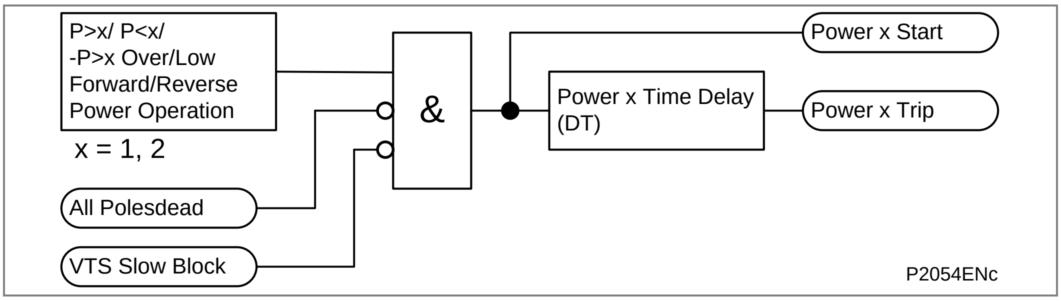


Figure 41 - Power logic diagram

1.16.1 Sensitive Power Protection Function

For steam turbine generators and some hydro-generators a reverse power setting as low as 0.5%Pn is required. A sensitive setting for low forward power protection may also be required, especially for steam turbine generators that which have relatively low over speed design limits.

To improve the power protection accuracy, a dedicated CT input can be used connected to a metering class CT. The CT input is the same as that of the sensitive earth fault and restricted earth fault protection elements, so the user can only select either sensitive power or SEF/REF in the **Configuration** menu, but not both.

The sensitive power protection measures only one single phase active power, as the abnormal power condition is a three-phase phenomenon. Which phase active power was selected dependent on the setting value ϕ of Phase Select (ϕ= A, B or C), if ϕ= B, phase B was selected, the active power would be produced by phase B current and phase B voltage.

Having a separate CT input also means that a correctly loaded metering class CT can be used which can provide the required angular accuracy for the sensitive power protection function. A compensation angle setting θC is also be provided to compensate for the angle error introduced by the system CT and VT.

The ϕ -phase power is calculated based on this formula:

$$PA = I\phi \; V\phi \cos(\varphi - \theta C)$$

Where φ is the angle of $I\phi$ with respect to $V\phi$ and θC is the compensation angle setting.

Therefore, rated single-phase power, Pn, for a 1A rated CT and 110 V rated VT is:

$$Pn = In \times Vn = 1 \times 110/\sqrt{3} = 63.5\text{ W}$$

The minimum setting is 0.3 W = 0.47% Pn

Two stages of sensitive power protection are provided, these can be independently selected as either reverse power, over power, low forward power or disabled, and operation in each mode is described in the following sections.

The power elements may be selectively disabled, via fixed logic, so that they can be inhibited when the protected machine’s CB is open, this will prevent mal-operation and nuisance flagging of any stage selected to operate as low forward power.

The relay is connected with the convention that the forward current is the current flowing from the generator to the busbar. This corresponds to positive values of the active power flowing in the forward direction. When a generator is operating in the motoring mode, the machine is consuming active power from the power system. The motoring active power therefore flows in the reverse direction. The **Operating Mode** setting for the sensitive power protection allows the user to set the operating mode to either **Generating** or **Motoring**. If the mode is set to **Motoring**, the polarity of the calculated active power is inverted. The operating mode setting can be useful in applications involving pumped storage generators.

The two stages of sensitive power protection in the relay are provided with a timer hold (drop off timer) facility, which may either be set to zero or to a definite time value. Setting of the timer to zero means that the power timer for that stage will reset instantaneously once the current falls below 90% of the power setting. Setting of the hold timer to a value other than zero, delays the resetting of the protection element timers for this period. For an intermittent fault when the reset time (drop-off time) of the sensitive power protection 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 power pulses, thereby reducing fault clearance times.

The timer hold (drop off timer) facility can be found for the two sensitive power stages as settings Power 1 DO Timer and Power 2 DO Timer respectively.

Measurement displays of ϕ Phase sensitive active power, reactive power and power factor angle ϕ **Ph Sen Watts**, ϕ **Ph Sen Vars** and ϕ **Ph Power Angle** are provided in the MEASUREMENTS 3 menu to aid testing and commissioning.

DDB signals are available to indicate starting and tripping of each stage (Starts: DDB 1142, DDB 1143, Trips: DDB 884, 885). 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.

The sensitive power starts are mapped internally to the ANY START DDB signal – DDB 992.

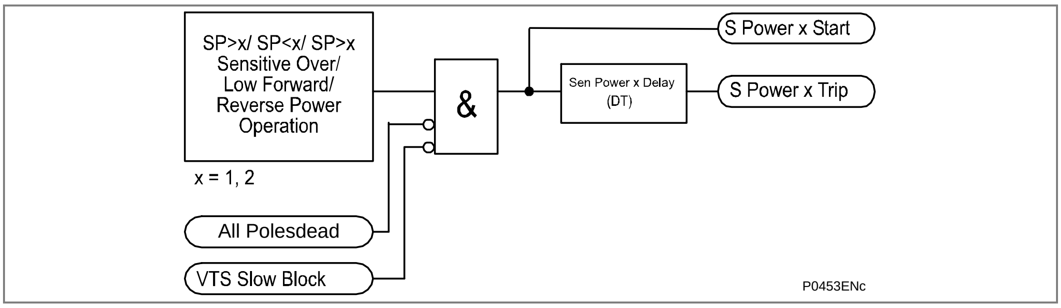


Figure 42 - Sensitive power logic diagram

The Sensitive power connections are shown in the *P343 Generator protection relay with biased differential using VEE connected VT's and sensitive power (16 I/P & 14 O/P)* diagram in the Connection Diagrams chapter.

1.17 Stator Earth Fault Protection (50N/51N)

A two-stage non-directional earth fault element is provided. The first stage has an inverse time or definite time delay characteristic and can incorporate a reset time delay to improve detection of intermittent faults. The second stage has a definite time characteristic that can be set to 0 s to provide instantaneous operation. For further details regarding the inverse time characteristics refer to:

- Section 1.5 - Overcurrent Protection (50/51)

The logic diagram for non-directional stator earth fault overcurrent is shown in below:

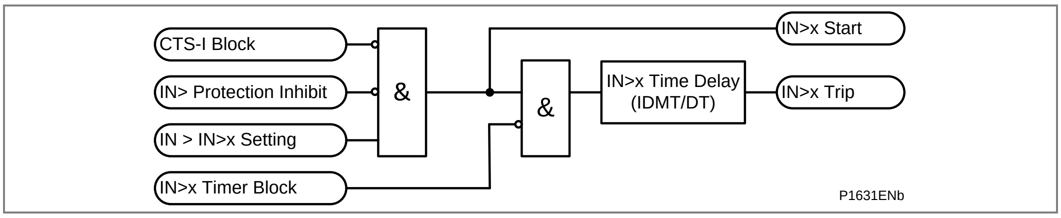


Figure 43 - Non-directional EF logic (single stage)

A timer block input is available for each stage which will reset the earth fault timers of the relevant stage if energized, taking account of the reset time delay if selected for the **IN>1** stage (DDB 544, DDB 545). DDB signals are also available to indicate the start and trip of each stage of protection, (Starts: DDB 1008, DDB 1009, Trips: DDB 768, DDB 769). 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.

The stator earth fault protection starts are mapped internally to the ANY START DDB signal – DDB 992.

The Stator Earth Fault element is powered from the In CT input on the relay.

1.17.1 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:

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

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.

The following *IDG characteristic* diagram shows how the IDG characteristic is implemented.

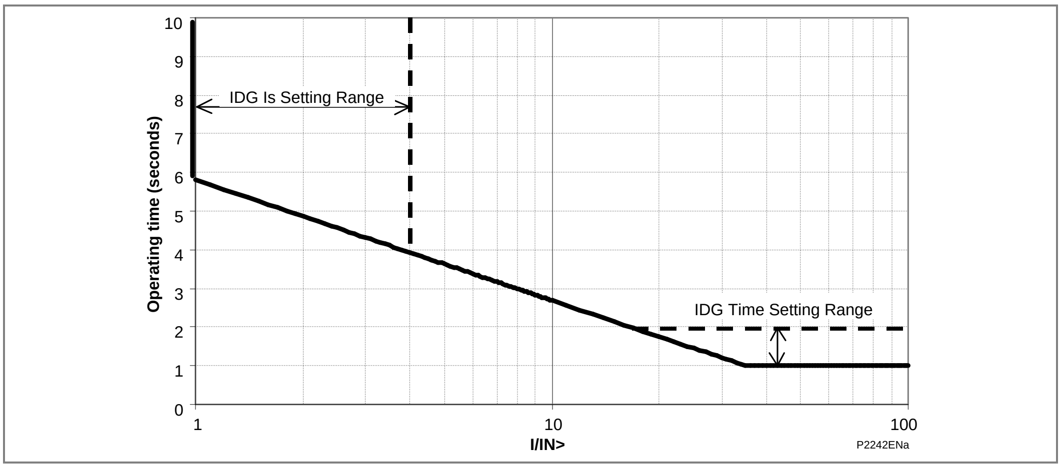


Figure 44 - IDG characteristic

1.18 Residual Overvoltage/Neutral Voltage Displacement Protection (59N)

The neutral voltage displacement protection function of the P342/P343 relays consist of two stages of derived (VN>1, VN>2) and two stages of measured (VN>3, VN>4) neutral overvoltage protection with adjustable time delays.

The P344/P345 has an additional two stages of measured (VN>5, VN>6) neutral overvoltage protection as it has a dedicated second neutral voltage input, VN(2).
The relay derives the neutral/residual voltage operating quantity from this equation:

Vneutral = Va + Vb + Vc

A dedicated voltage input (one VN1 input is available in the P342/P343 and two VN1/2 inputs are available in the P344/P345) is provided for this protection function. This may be used to measure the residual voltage supplied from either an open delta connected VT or the voltage measured on the secondary side of a distribution transformer earth connection, as shown in the *Alternative relay connections for residual overvoltage/NVD protection* diagram. Alternatively, the residual voltage may be derived internally from the three-phase to neutral voltage measurements. Where derived measurement is used the three-phase to neutral voltage must be supplied from either a 5-limb or three single-phase VTs. 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 when residual voltage is required to be derived from the phase to neutral voltage measurement.
The residual voltage signal can be used to provide interturn protection as well as earth fault protection. The residual voltage signal also provides a polarizing voltage signal for the sensitive directional earth fault protection function.

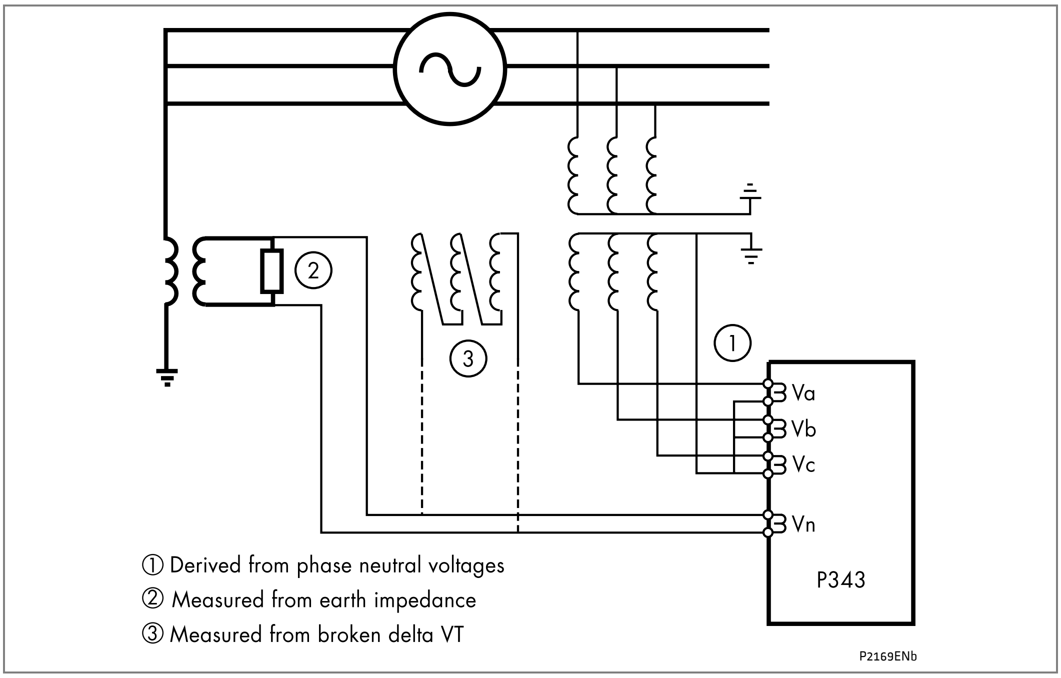


Figure 45 - Alternative relay connections for residual overvoltage/NVD protection

The functional block diagram of the first stage residual overvoltage is shown in the *Residual overvoltage logic (single stage)* diagram.

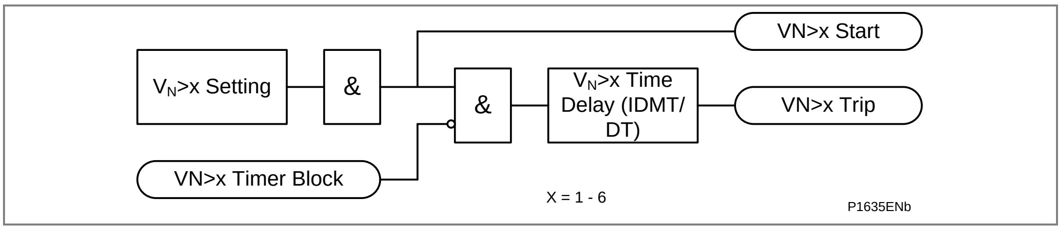


Figure 46 - Residual overvoltage logic (single stage)

VTS blocking when asserted, effectively blocks the start outputs. Only the derived neutral voltage protection stages (VN>1, VN>2) are blocked by the VT Supervision.

A timer block input is available for each stage which will reset the residual overvoltage timers of the relevant stage if energized, (DDB 592-597). DDB signals are also available to indicate the start and trip of each stage of protection, (Starts: DDB 1088-1093 Trips: 832-837). 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.

The residual overvoltage fault protection starts are mapped internally to the ANY START DDB signal – DDB 992.

The IDMT characteristic available on the first stage is defined by the following formula:

$$t = K/(M - 1)$$

Where:

K = Time multiplier setting (VN<1 TMS)

t = Operating time in seconds

M = Measured voltage/relay setting voltage (VN< Voltage Set)

1.19 Sensitive Earth Fault Protection (50N/51N/67N/67W)

A single stage definite time sensitive earth fault protection element is provided in the relay, this element can be set to operate with a directional characteristic when required.

A separate sensitive earth fault element is provided within the relay for the operating current, this has a dedicated CT input allowing very low current setting thresholds to be used. When directional earth fault protection is required the operating current should be derived from either a core balanced CT or the residual connection of three-phase CTs at the terminals of the machine. Direction of the earth fault current for this element is determined with reference to the polarizing signal, the residual voltage. The polarizing signal is taken from the residual overvoltage/NVD protection input (VN1 input for P342/P343/P344/P345) or derived from the three-phase neutral voltage inputs on the relay.

A polarizing voltage threshold is also provided. The element cannot operate unless voltage exceeds this threshold. This helps to restrain the element during phase/phase faults when transient CT saturation produces spill current in the residual connection of the phase CTs. No residual voltage will be present during such non-earth fault conditions hence the DEF element cannot operate. The element will therefore be enabled only during genuine earth fault conditions when significant residual voltage will be present. To prevent the element from mal-operating due to VT fuse failure the element can be blocked from the VT supervision logic by setting the ISEF Func. Link - Block ISEF from VTS to 1. If the ISEF Func. Link is set to 0 the SEF element will revert to non-directional upon operation of the VTS.

Where Petersen Coil earthing is used, users may wish to use Wattmetric Directional Earth Fault protection or an $I\cos\phi$ characteristic. Settings to enable the element to operate as a wattmetric element are also provided. For insulated earth applications, it is common to use the $I\sin\phi$ characteristic.

The Sensitive Earth Fault protection can be blocked by energizing the relevant DDB signal via the PSL (DDB 548). This allows the protection to be integrated into busbar protection schemes as shown in the *Circuit Breaker Failure Protection (50BF)* section, or can be used to improve grading with downstream devices. DDB signals are also available to indicate the start and trip of the protection, (Start: DDB 1012, Trips: DDB 773). 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	*ISEF> Func Link – bit 0 When this 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.*

The logic diagram for sensitive directional earth fault protection with neutral voltage polarization is shown in the *Directional SEF with VN polarization* diagram.

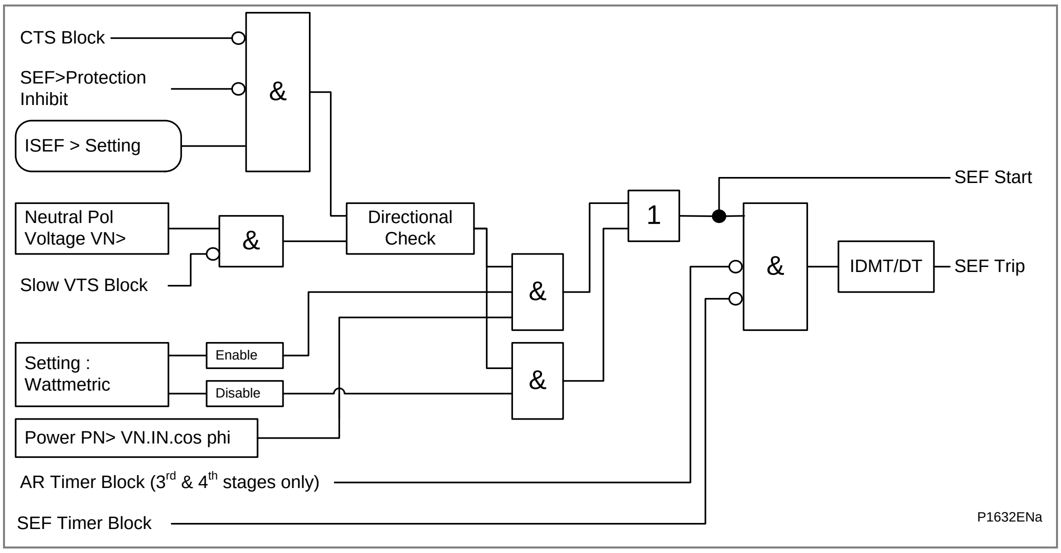


Figure 47 - Directional SEF with VN polarization

The directional check criteria are given below for the standard directional sensitive earth fault element:

Directional forward

-90° < (angle(IN) - angle(VN + 180°) - RCA) < 90°

Directional reverse

-90° > (angle(IN) - angle(VN + 180°) - RCA) > 90°

1.20 Restricted Earth Fault (REF) Protection (64)

The Restricted Earth Fault (REF) protection in the 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.

A DDB signal is available to indicate the tripping of the REF protection, (DDB 772). 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.

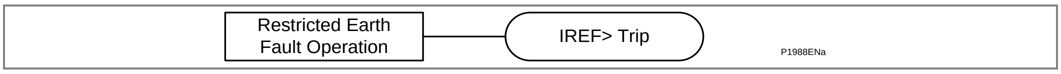


Figure 48 - Restricted earth fault logic diagram

1.20.1 Low-Impedance Biased Differential REF 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.

The following *REF bias characteristic* diagram and the *REF bias principle* diagram show the operating characteristic for the relay applied for biased REF protection.

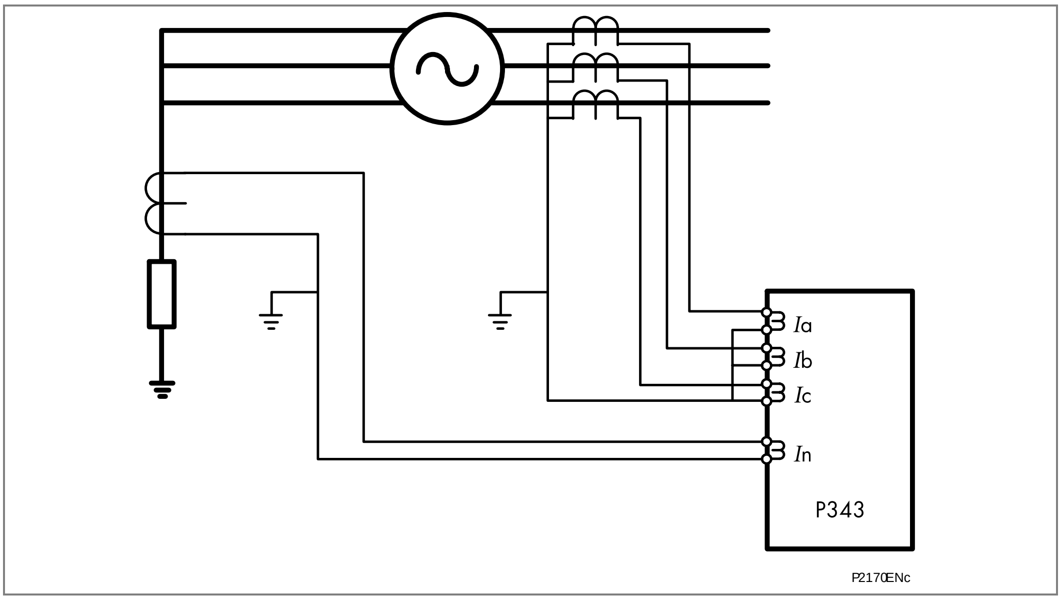


Figure 49 - REF bias characteristic

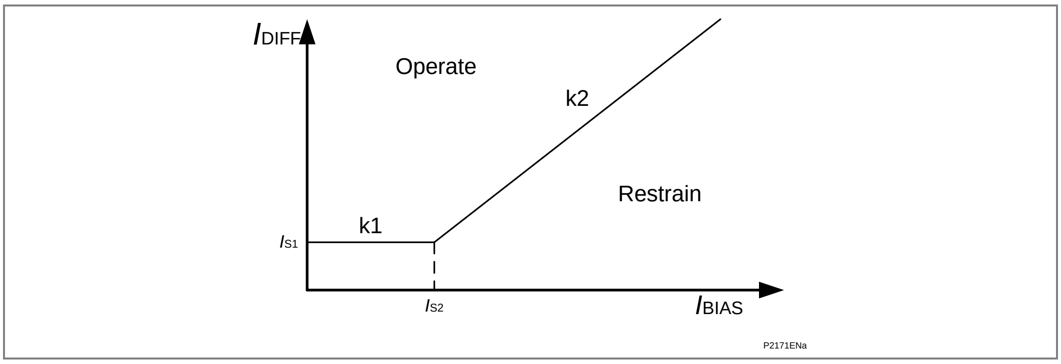


Figure 50 - REF biased principle

The *Neutral scaling for biased REF protection* diagram shows the three line CTs are connected to the three-phase CTs in the normal manner. The 3 phase current source for the line CTs can be selected using the **IREF> CT Source – IA-1/IB-1/IC-1** or **IA-2/IB-2/IC-2** setting. The neutral CT is then connected to the stator earth fault CT input. These currents are then used internally to derive both a bias and a differential current quantity for use by the low impedance biased differential REF protection.

The advantage of this method of connection is that the line and neutral CTs are not differentially connected and so the neutral CT can also be used to drive the stator earth fault protection. Also, no external equipment such as stabilizing resistors or Metrosils are required, unlike the case with high impedance protection.

The formula used by the relay to calculate the required bias quantity is 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 in this diagram.

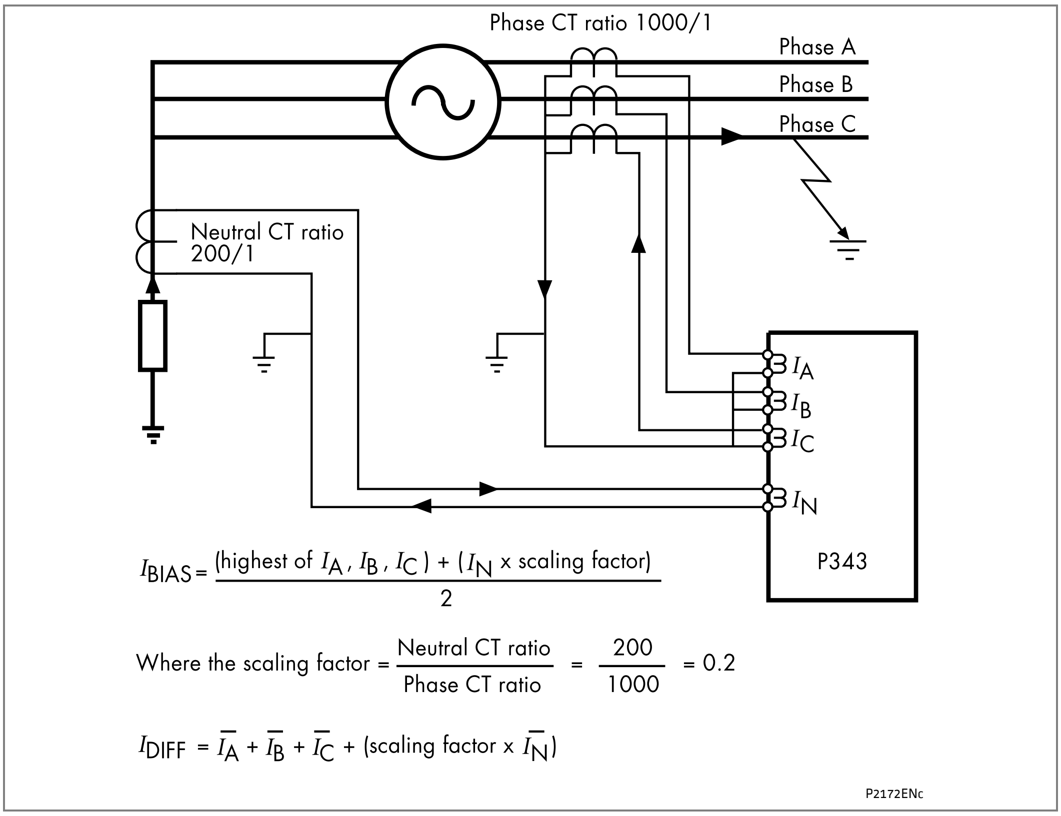


Figure 51 - Neutral scaling for biased REF protection

Where it is required that the neutral CT also drives the stator earth fault protection element, 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. 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 to compensate for any mismatch.

1.20.2 High Impedance Restricted Earth Fault 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 52 - Principle of high impedance differential protection

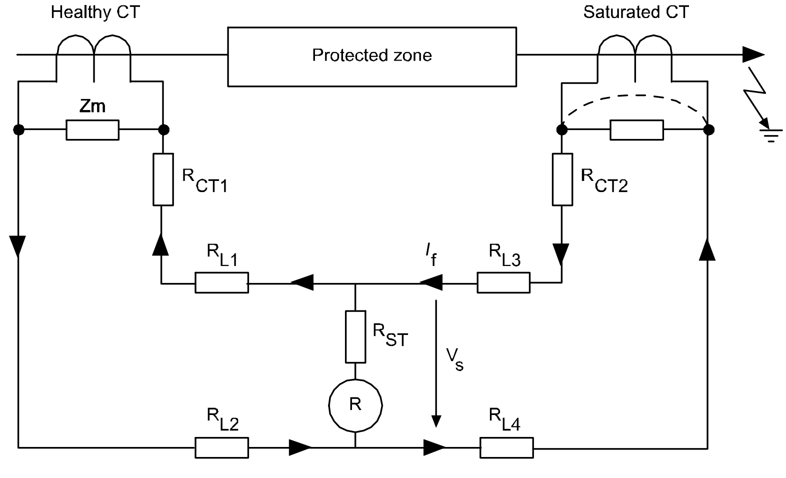
If the relay circuit is considered to be a very high impedance, the secondary current produced by the healthy CT will flow through the saturated CT. If CT magnetizing impedance of the saturated CT is considered to be negligible, the maximum voltage across the relay circuit will be equal to the secondary 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, RST, is calculated by the formula shown in:

Figure 53 - Relay connections for high impedance REF protection

An additional non-linear resistor, Metrosil, may be required to limit the peak secondary circuit voltage during internal fault conditions.

To ensure the protection will operate quickly during an internal fault the CTs used to operate the protection must have a kneepoint voltage of at least 4 Vs.



Voltage across relay circuit

$$V_s = KI_f\ (R_{CT} + 2R_L) \text{ - where K = 1}$$

Stabilising resistor, R_{ST}, limits spill current to I_s (relay setting)

$$R_{ST} = \frac{V_s}{I_s} - R_R$$

Where: I_F = Maximum secondary through fault current
R_R = Relay burden
R_{CT} = Current transformer secondary winding resistance
R_L = Resistance of a single lead from the relay to the current transformer

P0115ENf

Figure 52 - Principle of high impedance differential protection

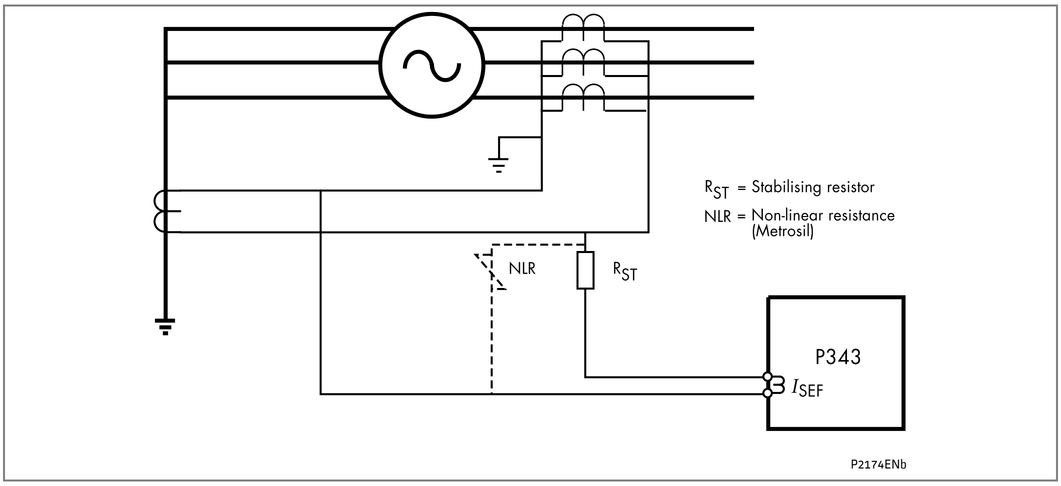


Figure 53 - Relay connections for high impedance REF protection

The necessary relay connections for high impedance REF are shown in the above diagram.

The high impedance protection uses an external differential connection between the line CTs and neutral CT. The SEF input is then connected to the differential circuit with a stabilizing resistor in series.

1.21 100% Stator Earth Fault Protection (3rd Harmonic Method) (27TN/59TN)

To detect faults in the last 5% of the generator winding, the P343/P344/P345 relay is provided with a third harmonic undervoltage and overvoltage element. These, together with the residual overvoltage or stator earth fault protection elements, will provide protection for faults over the complete winding.

The third harmonic neutral under voltage element is applicable when the neutral voltage measurement is available at the neutral end of the generator. It is supervised by a three-phase under voltage element, which inhibits the protection when all the phase-phase voltages at the generator terminal are below the threshold, to prevent operation when the machine is dead, interlocking may also be required to prevent false operation during certain conditions. For example, some machines do not produce substantial third harmonic voltage until they are loaded. In this case, the power supervision elements (active, reactive and apparent power) could be used to detect load to prevent false tripping under no load conditions. These power thresholds can be individually enabled and disabled and the setting range is from 2 - 100%Pn.

For applications where the neutral voltage measurement can only be obtained at the generator terminals, from a broken delta VT for example, the under voltage technique cannot be applied. Therefore the third harmonic neutral over voltage element can be used for this application. The blocking features of the under voltage and power elements are not required for the 3rd harmonic neutral over voltage element.

Note	*The relay can only select 3rd harmonic neutral under voltage or 3rd harmonic neutral over voltage, but not both.*

The logic diagrams of the two protection schemes are shown in this diagram:

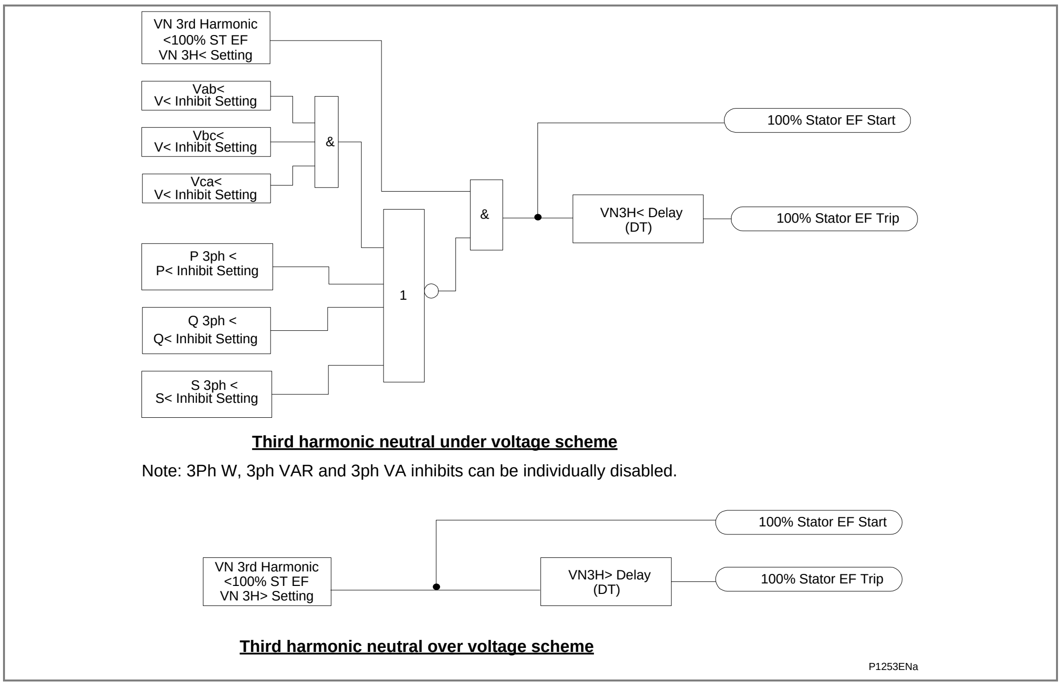


Figure 54 - 100% stator earth fault protection block diagram

DDB signals are available to indicate the start and trip of the protection, (Start: DDB 1016, Trip: DDB 777). 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.

The 100% stator earth fault protection start is mapped internally to the ANY START DDB signal – DDB 992.

1.22 100% Stator Earth Fault Protection (Low Frequency Injection Method) (64S)

The 100% stator earth fault protection using a low frequency injection technique detects earth faults in the entire winding, including the generator neutral point.

100% stator earth fault protection can be provided by injecting an external low frequency alternating voltage into the starpoint or the terminals of the machine. Under normal healthy conditions only a very small current flows via the stator earth capacitance due to the high impedance of this path at low frequencies ($X_c = 1/2\pi fc$). In the event of an earth fault the measured current increases due to the smaller impedance of the earth fault path. From the injected voltage and the fault current the relay can determine the fault resistance. The protection can also detect earth faults at the generator terminals including connected components such as voltage transformers.

A loading device with a low frequency generator is required for implementation. The output of the low frequency signal generator (approx 25 V) is connected via a bandpass filter in parallel with a loading resistor to a neutral transformer at the generator starpoint or an earthing (broken delta) transformer at the terminals of the generator. The bandpass filter provides rounding of the square-wave voltage and energy storage. The higher series resistance of the bandpass filter (approx. 8 Ω at 20 Hz) protects the 20 Hz generator from excessive feedback current if the load resistor carries the full displacement voltage during a terminal phase-earth fault.

The loading resistor is connected in parallel with the low frequency generator to generate a defined neutral current in normal healthy conditions. The voltage to be injected into the generator starpoint depends on the driving 20 Hz voltage (voltage divider: load resistor and bandpass), and on the transformation ratio of the neutral or earthing transformer. To prevent the secondary load resistance from becoming too small (it should be > 0.5 Ω where possible) a high secondary voltage, such as 500 V, should be chosen for the neutral or earthing transformer. It is important that the earthing transformer never becomes saturated otherwise ferroresonance may occur. It is sufficient that the transformer knee point voltage be equal to the generator rated line voltage. The low frequency voltage is fed to the relay via a voltage divider and the low frequency measuring current is fed via a miniature current transformer. All interference deviating from the nominal low frequency signal is filtered out.

The 100% stator earth fault protection can also be applied with a primary loading resistor. The 20 Hz voltage is connected via a voltage transformer and the neutral starpoint current is directly measured via a CT, see the Application Notes chapter.

From the measured current and voltage vectors the complex impedance can be calculated and from this the ohmic resistance is determined. This eliminates disturbances caused by the stator earth capacitance and ensures high sensitivity. The relay algorithm can take into account a transfer resistance 64S Series R that may be present at the neutral or earthing voltage transformer. An example of the series resistance is the total leakage resistance of the earthing or neutral transformer, through which the injected voltage is applied to the generator neutral. The algorithm can also account for parallel resistance, 64S Parallel G (G = 1/R), such as the additional loading equipment connected on the LV side of the step-up transformer. Other error factors can be taken into account by the angle error compensation, 64 S Angle Comp.

From the measured current and voltage vectors the complex impedance can be calculated and from this the ohmic resistance is determined. This eliminates disturbances caused by the stator earth capacitance and ensures high sensitivity. The relay algorithm can take into account a transfer resistance 64S Series R that may be present at the neutral or earthing voltage transformer. An example of the series resistance is the total leakage resistance of the earthing or neutral transformer, through which the injected voltage is applied to the generator neutral. The algorithm can also account for parallel resistance, 64S Parallel G (G = 1/R), such as the additional loading equipment connected on the LV side of the step-up transformer. Other error factors can be taken into account by the angle error compensation, 64 S Angle Comp.

The relay includes a 20 Hz overcurrent element which can be used as a back-up to the 20 Hz under resistance protection. The overcurrent element is not as sensitive as the under resistance elements as it does not include any transfer resistance compensation or any compensation for capacitance affects.

The 100% stator earth fault protection includes 2 stages of under resistance protection and an overcurrent protection stage. The under resistance protection is designed as a two stage protection system, one alarm stage (64S R<1 Alarm) and one trip stage (64S R<2 Trip), with each stage having a definite time delay setting. The overcurrent stage (64S I> Trip) is a single protection stage with a definite time delay setting. All the protection stages have separate DDB signals to indicate the start and trip of each stage and DDB signals to inhibit operation of each stage.

The protection includes a supervision element to evaluate a failure of the low frequency generator or the low frequency connection. The operation of an undervoltage and an undercurrent element after a time delay are used to indicate a failure. In case of a failure the protection can be blocked and give an alarm using the PSL. There is a 64S Fail signal which is connected to the 64S Fail Alarm signal in the default PSL to raise the alarm led and message and also to inhibit the 64S I>1/R<1/R<2 protection stages. For applications where the 100% stator earth fault 20 Hz generator is powered from a voltage transformer an alarm led and message may not be wanted every time the machine is off line which is why the 64S Fail Alarm signal and 64S Fail signal are separated.

Note	*If required the 64S Fail Alarm or a User Alarm (Manual Reset User Alarm 5-16 is DDB 411-399) can be used to provide an alarm on the P345 via an opto-isolated input from the 20 Hz generator faulty output contact.*

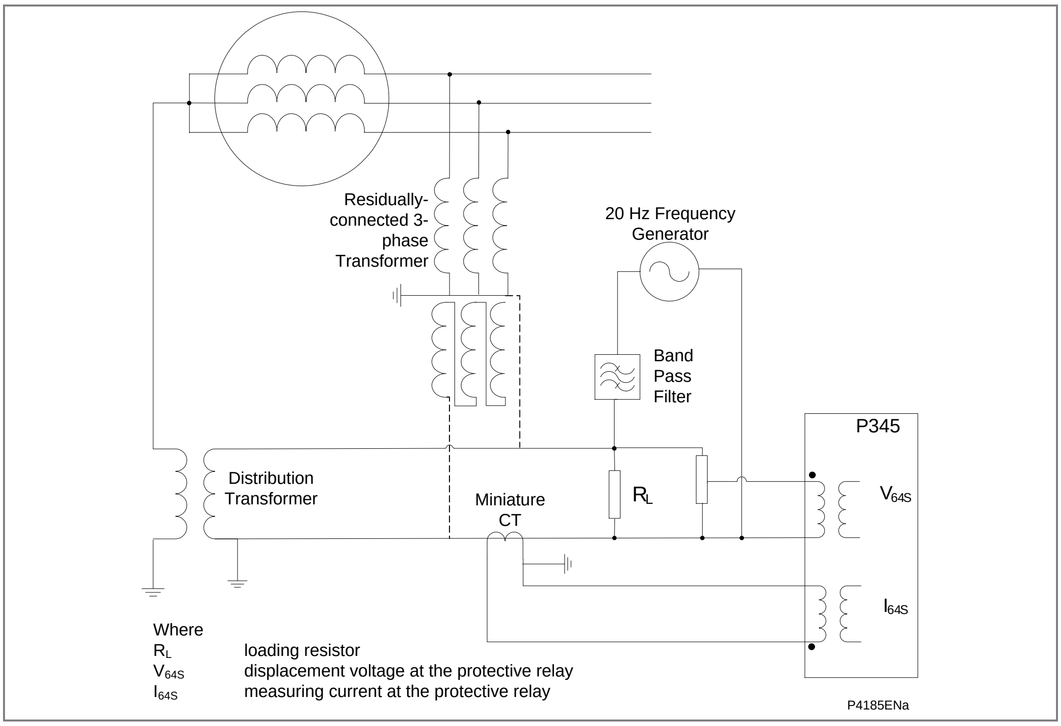


Figure 55 - 100% stator earth fault protection with earthing (broken delta) transformer or neutral transformer

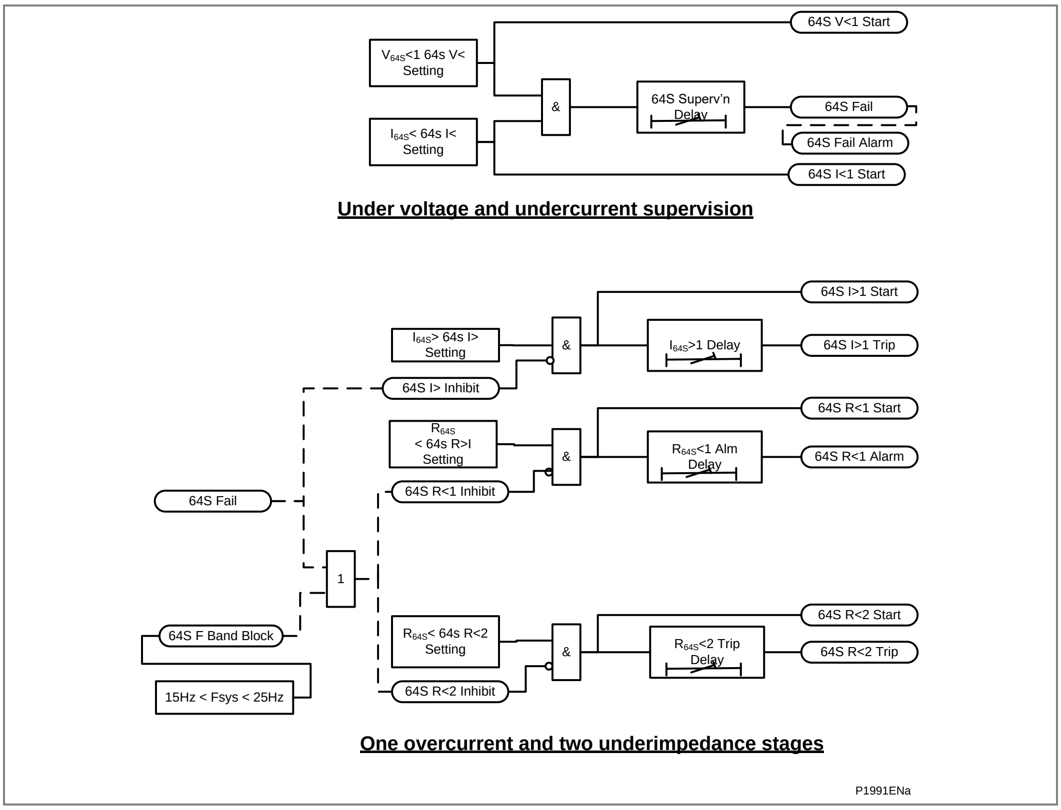


Figure 56 - 64S 100% stator earth fault logic diagram

The 64S R<1/R<2/I>1 stages can be independently inhibited by energizing the relevant DDB signal via the PSL (64S I>1/R<1/R<2 Inhibit: DDB 552/553/554). DDB signals are also available to indicate the start, alarm and trip of the protection stages, (64S I>1/R<1/R<2 Start: DDB 1019/1020/1021, 64S R<1 Alarm: DDB 394, 64S I>1/R<2 Trip: DDB 778/780). DDB signals are available for the start of the supervision undercurrent and undervoltage elements (64S I< Start, 64S V<1 Start: DDB 1017/1018) and for the supervision fail and alarm (64S Fail: DDB 1298, 64S Fail Alarm: DDB 383). The 64S Fail DDB is mapped to the 64S I>1/R<1/R<2 inhibit signals and 64S Fail Alarm signal in the default PSL.

The 100% stator earth fault protection starts are mapped internally to the ANY START DDB signal – DDB 992.

1.22.1 Measurements

The relay samples the applied voltage and the circulating current at multiples of 20 Hz. Filtering algorithms are applied to extract the 20 Hz components from these two signals. The voltage and current magnitudes and phase angles, together with the resistance value are calculated.

The voltage and current protection settings and measurements are available only in secondary quantities. The resistance measurements are available in both primary and secondary quantities. The resistance and conductance settings are also subject to the **Primary/Secondary** conversion controlled by the **Setting Values** setting in the Configuration column.

The conversion is via a single **64S R Factor** Setting as follows:

R Primary = R Secondary * R Factor

Examples of the setting calculations for the R Factor are shown in the Application Notes chapter.

An angle compensation setting, 64S Angle Comp, (θComp) is available to compensate for any CT angle error. The setting causes the current vector to be rotated by an angle θComp as shown.

$\overline{I'_{64SComp}} = \overline{I_{64s}} \times 1 \angle\theta_{Comp}$

The fault resistance Rf is derived from:

$\dfrac{\quad}{V_{64S}}$ and $\dfrac{\angle}{I'_{64s}}$

It is derived so that any effect of the series resistance (Rs) and parallel resistance (Rp) within the injection circuitry, together with any reactance in the circuit and the capacitance of the stator windings to ground (Cg) can be eliminated.

The derivation is based on the following model. Both Rs and Rp are user settings, 64S R Series, 64S G Parallel (G = 1/R, the default setting of 0 is equivalent to Rp = infinity). As only the resistive component of the impedance is derived the value of the capacitance to ground and any reactance need not be known, as this information is not required for the Rf calculation.

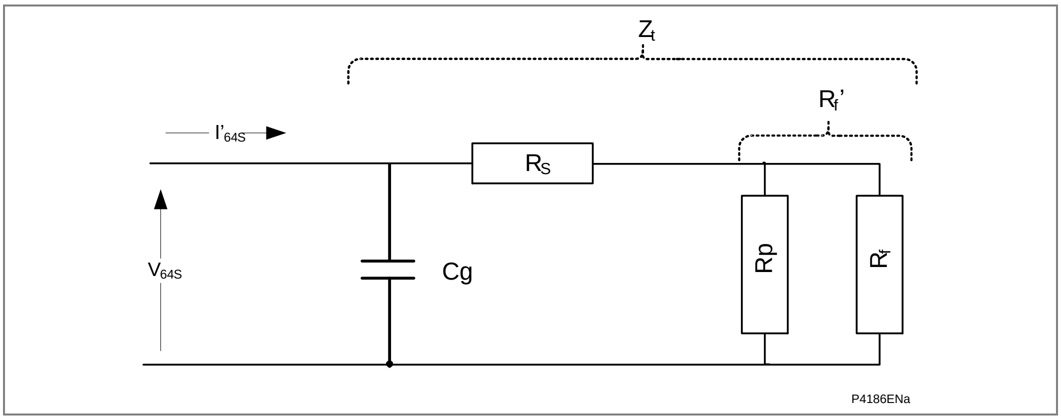


Figure 57 - Model for 100% stator earth fault by injection

The calculated fault resistance Rf is used as the operating quantity for the 2-stage definite-time under resistance protection.

A definite-time overcurrent element is available as backup, with the 20 Hz current signal as the operating quantity.

The following measurements are available in the Measurements 3 column. All measurements are based on the 20 Hz components extracted from the voltage and current signals. A magnitude threshold level of 0.05 V and 0.1 mA for the voltage and current is implemented, below which the associated measurements display zero. The 64S R is the compensated resistance in both primary and secondary quantities. The resistance measurement displays a forced value to indicate an invalid measurement if either the voltage or the current magnitude is below the threshold.

MEASUREMENTS 3
64S V Magnitude
64S I Magnitude
64S I Angle
64S R secondary
64S R primary

Table 9 - Measurements settings

Condition	Forced value 64S R
Protection disabled	999 MΩ
|V64S| < 100 mV	998 MΩ
|I64S| < 1 mA	997 MΩ
64S G Parallel x 64S R ⩾ 1.0	996 MΩ

Table 10 - Forced values for 64S

Note	The above conditions are in descending priority order. The forced value primary scaled equivalent values will have exactly the same values, irrespective of the primary scaling factor setting.

The 64S Voltage signal is always used as the phase reference for the 64S current signal. The measurements are available in the Modbus and DNP3 interfaces. The **64S V Magnitude**, **64S I Magnitude** and **64S R secondary** are also available in the fault records.

The Disturbance recorder analogue input selection (G31) includes V_{64S} and I_{64S}. They are sampled at the recorder's sampling frequency (24 samples/power system cycle).

1.22.1.1 100% Stator Earth Fault Filter Characteristics

The P345s 64S protection has a very powerful band pass filter tuned to 20 Hz which is switched in when the system frequency is below 45 Hz. The band pass filter is designed with an attenuation of at least -80 db for frequencies less than 15 Hz and greater than 25 Hz. -80 db is equivalent to a noise rejection capability with a noise-to-signal ratio of 10000 to 1. The band-pass filter introduces an additional delay to the protection, but it is able to prevent low power system frequency components from interfering with the resistance calculation. There is also a low pass filter tuned to filter frequencies >30 Hz which is permanently enabled and is designed with an attenuation of at least -80 dB for frequencies >45 Hz to filter high power system frequency components. The settling time of the band-pass filter is longer than the low pass filter and so to achieve faster trip times when the generator is fully run-up to rated speed the band-pass filter is automatically switched out above 45 Hz. An option is available to switch-in the band-pass filter permanently by energizing the **64S Filter On** DDB. There is also Fourier filtering of the 20 Hz current and voltage inputs based on a fixed tracking frequency of 20 Hz.

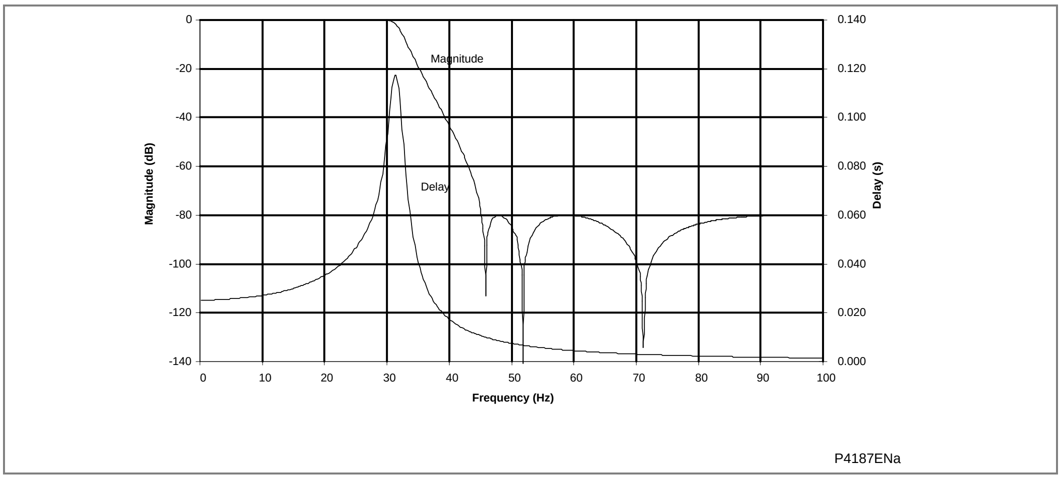


Figure 58 - 64S elliptic 8th order low pass filter discrete frequency response

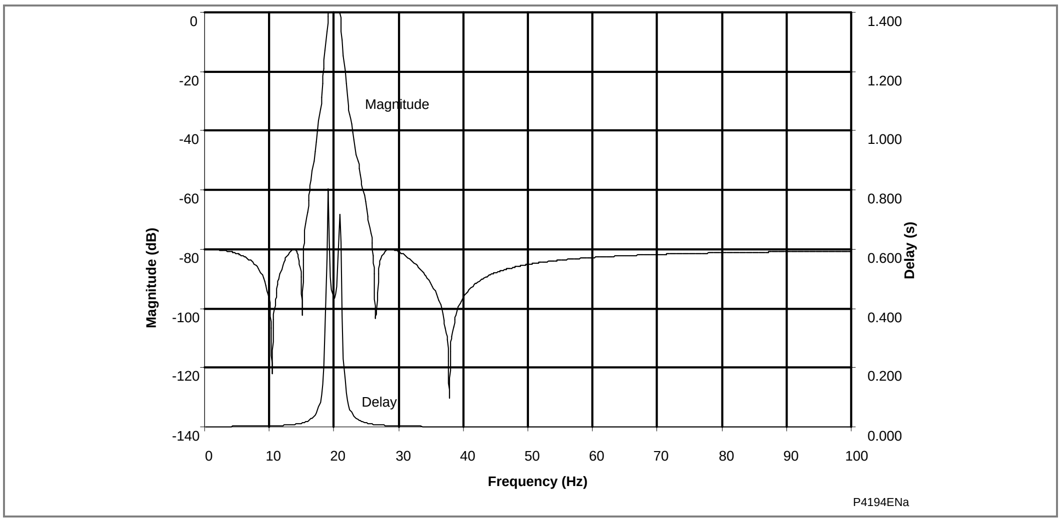


Figure 59 - 64S Elliptic 4th order band pass filter discrete frequency response

When the machine is running up and the frequency of the machine coincides with the 20 Hz injected signal, if there is an earth fault at this time then there will be some interference from the 20 Hz fault signal from the machine with the injected 20 Hz signal.

This may cause the 64S measurements to be incorrect which may result in the protection not tripping. However, as the machine speeds up and the machine frequency moves away from 20 Hz then the relay will begin to accurately measure the injected 20 Hz signal and fault resistance. The bandpass filter will nearly fully attenuate any frequencies above 25 Hz so by the time the machine frequency has reached 25 Hz the relay will correctly measure the fault resistance if there is a fault present and trip correctly.

If the 100% stator earth fault protection operates during the generator start up there may be some zero sequence voltage being produced by the machine that coincides and is superimposed onto the 20 Hz injected signal, depending on the type of starting, causing incorrect measurements. The P345 100% stator earth fault protection includes a low pass filter and a bandpass filter which will filter signal frequencies 0-15 Hz and >25 Hz. DDB 1297 64S F Band Block operates when the frequency is between 15-25 Hz and can be used in the PSL to indicate a frequency in the target measuring range, 15-25 Hz. DDB signal 1297 can if necessary be used to block the 100% stator earth fault protection between 15-25 Hz via the inhibit signals, DDBs 552 - 64S I> Inhibit, DDB 553 - 64S R<1 Inhibit, DDB 554 - 64S R<2 Inhibit, see the *64S Elliptic 4th order band pass filter discrete frequency response* diagram above. Note, DDB 1297 64S F Band Block is only active if frequency tracking is active. The frequency is active if any phase voltage is >0.1 Vn or any phase current is >0.05 In, see the Product Design chapter.

1.23 Overfluxing Protection (24)

The P342/P343/P344/P345 relays provide a five stage overfluxing element. The element measures the ratio of voltage, (VAB), to frequency, V/Hz, and will operate when this ratio exceeds the setting. One stage can be set to operate with a definite time or inverse time delay (IDMT), this stage can be used to provide the protection trip output. There are also 3 other definite time stages which can be combined with the inverse time characteristic to create a combined multi-stage V/Hz trip operating characteristic using PSL. An inhibit signal is provided for the V/Hz>1 stage 1 only, which has the inverse time characteristic option. This allows a definite time stage to override a section of the inverse time characteristic if required. The inhibit has the effect of resetting the timer, the start signal and the trip signal.

There is also one definite time alarm stage that can be used to indicate unhealthy conditions before damage has occurred to the machine.

The V/Hz>1 stage can be inhibited by energizing the relevant DDB signal via the PSL (V/Hz>1 Inhibit: DDB 625). DDB signals are also available to indicate the start and trip of the protection, (Start: DDB 1068-1171, Trip: DDB 912-915). A further DDB 'V/Hz Alarm' signal is generated from the overfluxing alarm stage (DDB 372). 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.

The overfluxing protection starts are mapped internally to the ANY START DDB signal – DDB 992.

The inverse time characteristic has this formula:

$$t = \frac{TMS}{(M-1)^2}$$

Where:

$$M = \frac{V/f}{(\text{V/f Trip Setting})}$$

V = Measured voltage

F = Measured frequency

Note, the IDMT characteristic has been changed in the 31 version software. The new characteristic is compatible with the old one and allows the option of future expansion of the number of characteristics with different exponents of (M-1).

Inverse time characteristic in software version 30 and lower is as shown below:

$$t = 0.8 + \frac{0.18 * TMS}{(M - 1)^2}$$

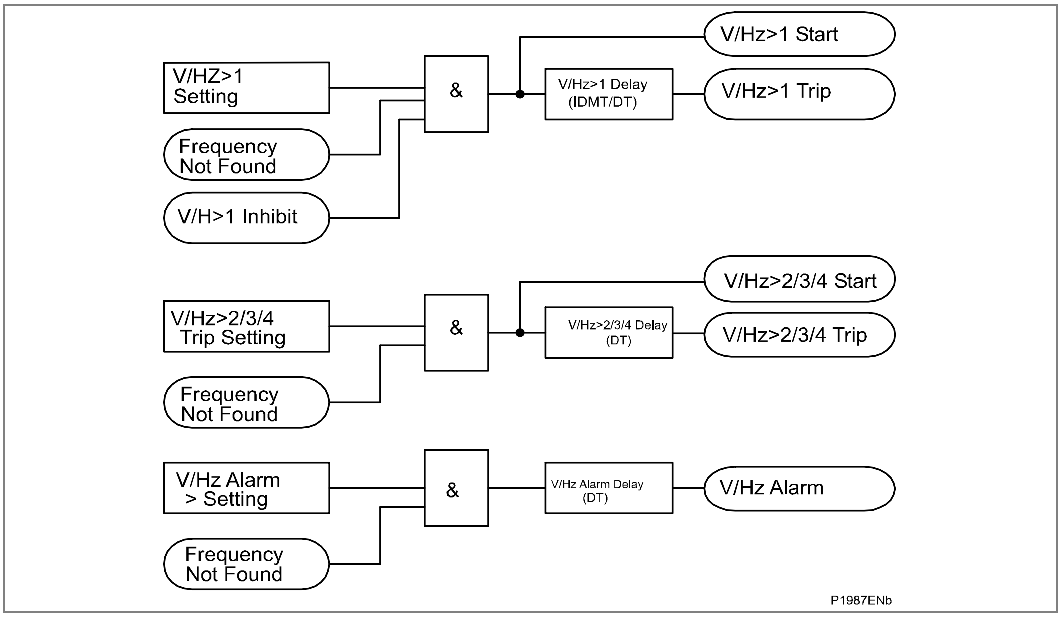


Figure 60 - Overfluxing logic diagram

1.24 Rate of Change of Frequency Protection (81R)

The df/dt function can be used to isolate an embedded generator connected to the utility's supply system under 'loss of mains' condition or for load shedding applications. An increase or decrease of the system frequency (df/ft) will be directly related to a sudden change of load on the generator. 4 stages of df/dt protection are included in relay. The first stage, df/dt>1 is designed for loss of grid applications but can also be used for load shedding. For the first stage only, the user can select a deadband around the nominal frequency, within which this element is blocked. The dead band is defined with high and low frequency settings **df/dt>1 f Low** and **df/dt> f High**. The deadband is eliminated if the high and low frequencies are set the same or the **df/dt> f L/H** setting is set to **Disabled**. The deadband provides additional stability for non loss of grid disturbances which do not affect the machine frequency significantly. Each stage has a direction setting **df/dt>n Dir'n – Negative, Positive, Both**. This setting determines whether the element will react to rising or falling frequency conditions respectively, with an incorrect setting being indicated if the threshold is set to zero. For loss of mains applications the **df/dt>1 Dir'n** should be set to **Both** to match the previous P341 algorithm.

There are some global df/dt settings that affect all protection stages that can be used to smooth out the frequency measurements and provide stable operation of the protection, **df/dt avg cycles** and **df/dt iterations**. These settings enable the user to select the number of cycles the frequency is averaged over and the number of iterations of the averaged cycles before a start is given. Two **Operating Mode** settings are provided: **Fixed Window** and **Rolling Window** which are described below in detail. The **Fixed Window** setting is provided for compatibility with the previous P341 df/dt function which used two consecutive calculations of a 3 cycle fixed window to initiate a start.

The previous software version P341 df/dt element calculated the rate of change of frequency every 3 cycles by calculating the frequency difference over the 3-cycle period as shown below.

$$\frac{df}{dt} = \frac{f_n - f_{n\text{-}3cycle}}{3cycle}$$

Two consecutive calculations must give a result above the setting threshold before a trip decision can be initiated.

The df/dt feature is available only when the **df/dt** option is enabled in the **CONFIGURATION** menu. All the stages may be enabled/disabled by the **df/dt>n Status** cell depending on which element is selected.

1.24.1 Fixed Window

The df/dt calculation is based on a user definable fixed window, 2 to 12 cycles. A new value of df/dt is (re)calculated every window. Increasing the window size improves measurement accuracy but has the disadvantage of increasing the measurement calculation time.

The elapsed time between start and end frequency measurements is calculated by summing up all sample interval times (NSamp) within the df/dt window (2 to 12 cycles).

Fault detection delay time (cycles) = df/dt Iterations x df/dt Avg Cycles.

1.24.2 Rolling Window

The df/dt calculation is based on a user definable rolling window, 2 to 12 cycles. The window is a rolling buffer, so a new value of df/dt is (re)calculated every protection cycle execution. Increasing the window size improves measurement accuracy but has the disadvantage of increasing the measurement calculation time.

To help improve the accuracy of the df/dt measurement, the value of df/dt calculated is averaged; the length of the averaging buffer is the window size.

The elapsed time between start and end frequency measurements is calculated by summing up all sample interval times (NSamp) within the df/dt window (2 to 12 cycles).

P342/P343/P344 fault detection delay time (cycles)
= df/dt Avg Cycles + (df/dt Iterations-1) x 1/4).
Protection scheduler runs every ¼ cycle.

P345 fault detection delay time (cycles) = df/dt Iterations x df/dt Avg Cycles.

1.24.3 Logic Diagram

DDB signals are available to indicate starting and tripping of the df/dt element (Start: DDB 1184, 1185, 1186, 1187 Trip: DDB 928, 929, 930, 931). 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.

The df/dt start is mapped internally to the ANY START DDB signal – DDB 992.

The logic diagrams for the df/dt logic are as shown in the next two diagrams.

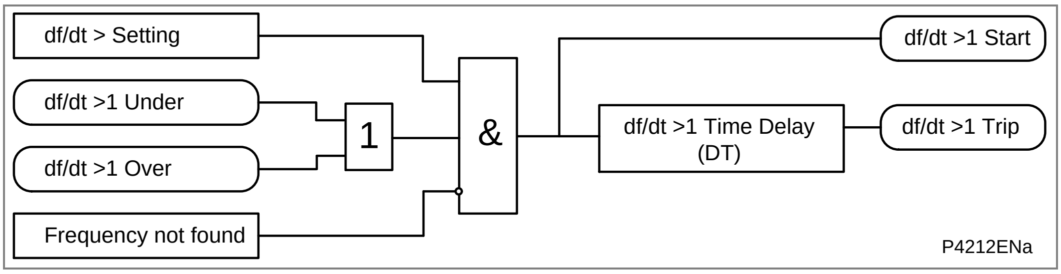


Figure 61 - Rate of change of frequency logic diagram for df/dt>1

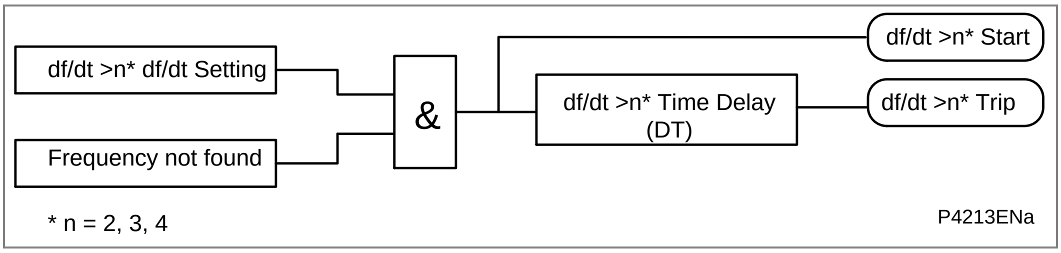


Figure 62 - Rate of change of frequency logic diagram for df/dt>2, 3, 4

1.25 Dead Machine/Unintentional Energization at Standstill Protection (50/27)

To provide fast protection for accidental energization of a generator when the machine is not running condition, the P343/P344/P345 relay provides an instantaneous overcurrent element that is gated with a three-phase undervoltage detector and is blocked by the VT supervision element. The scheme logic of this function is shown in the diagram below. The 3 phase current source can be selected using the **DM CT Source** – **IA-1/IB-1/IC-1** or **IA-2/IB-2/IC-2** setting.

A DDB signal is available to indicate tripping of the dead machine element (Trip: DDB 880). 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.

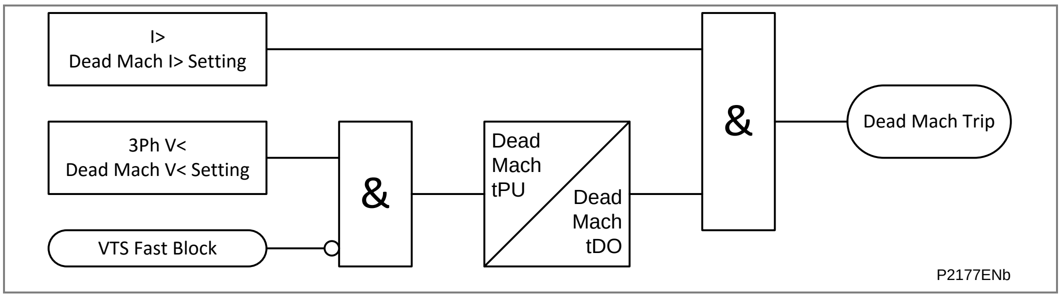


Figure 63 - Fixed scheme logic for unintentional energization of standstill protection

1.26 Resistive Temperature Device (RTD) Thermal Protection

To protect against any general or localized overheating, the P342/P343/P344/P345 relay has the ability to accept inputs from up to 10 - 3 wire Type A PT100 Resistive Temperature Sensing Devices (RTD). These are connected as shown in below:

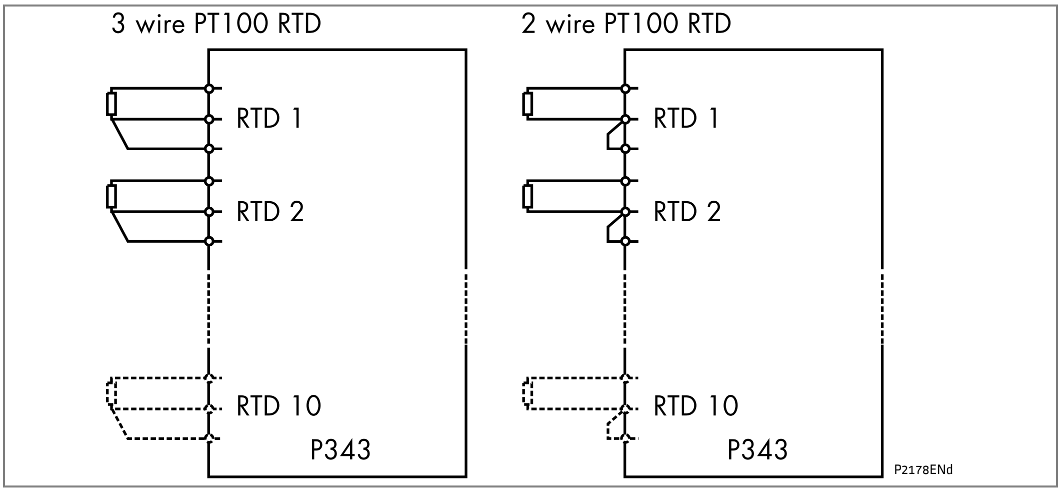


Figure 64 - Connection for RTD thermal probes

Such probes can be strategically placed in areas of the machine that are susceptible to overheating or heat damage.

- Typically a PT100 RTD probe can measure temperature within the range –40° to +300°C. The resistance of these devices changes with temperature, at 0°C they have a resistance of 100 Ω.

Should the measured resistance be outside of the permitted range, an RTD failure alarm will be raised, indicating an open or short circuit RTD input.

These conditions are signaled via DDB signals available within the PSL (DDB 375-378) and are also shown in the measurements 3 menu.

DDB signals are also available to indicate the alarm and trip of the each and any RTD, (Alarm: DDB 1304-1313, 374 Trip: DDB 976-985, 986). 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.

See the Installation chapter, for recommendations on RTD connections and cables.

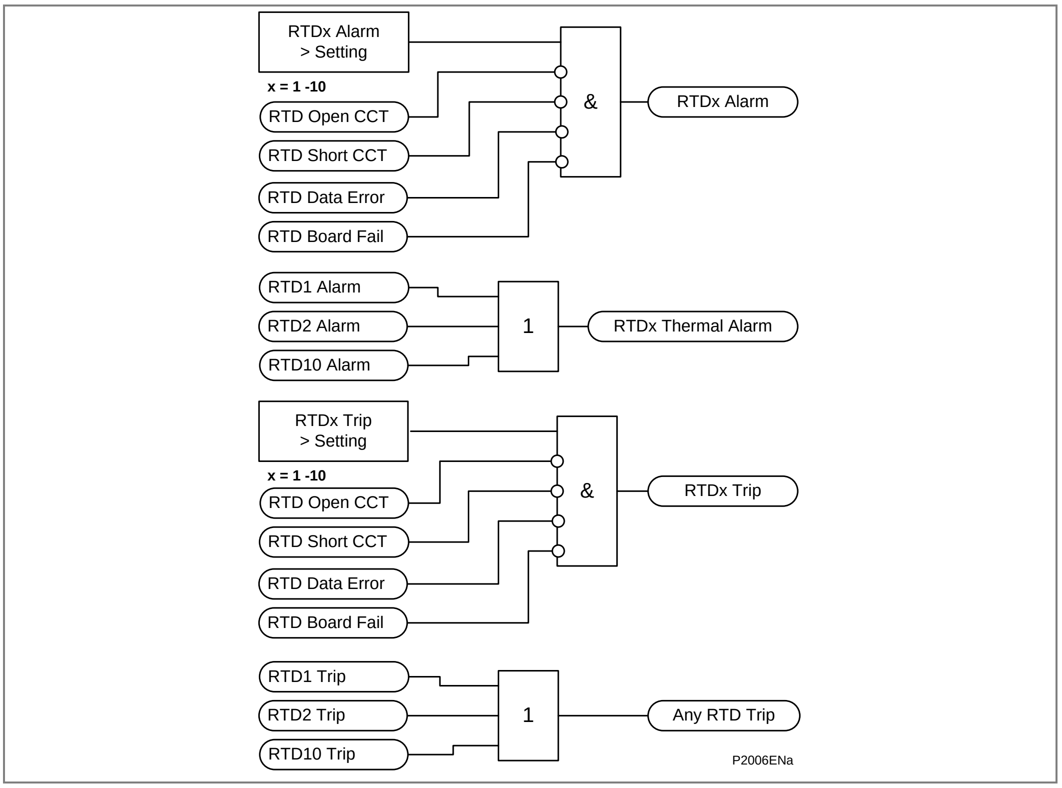


Figure 65 - RTD logic diagram

1.26.1 Principle of the RTD Connection

The aim of such a connection is to compensate the influence of the r1 and r2 resistors.

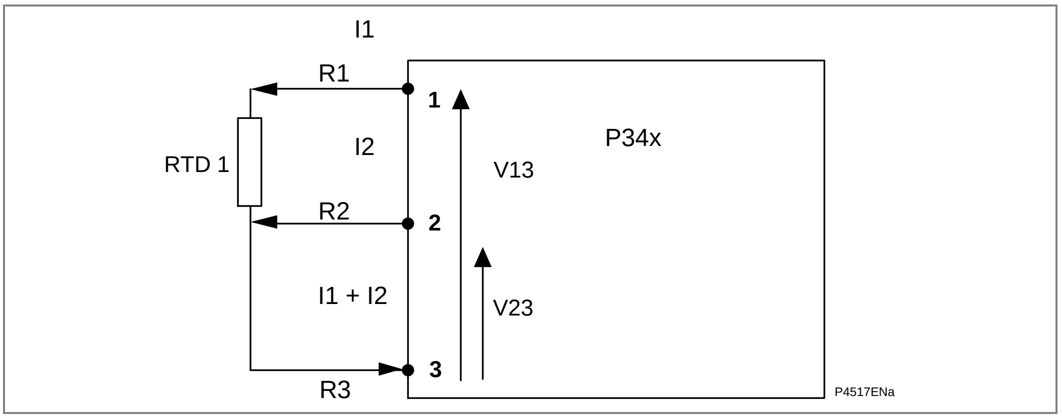


Figure 66 - Principle of RTD connection

A constant current is injected by the relay from the connections1 and 2: i1 = i2

V13 = r1 * I1 + R_{rtd} * I1 - r3 * (I1 + I2),

V23 = r2 * I2 - r3 * (I1 + I2),

V13 - V23 = r1 * I1 + R_{rtd} * I1 - r3 * (I1 + I2) - r2 * I2 + r3 * (I1 + I2)

Assuming that the three cables have the same length and are the same material, hence the resisitors r1, r2 and r3 are the same:

V13 - V23 = R_{rtd} * I1 = Voltage at the RTD terminals.

1.27 P343/P344/P345 Pole Slipping Protection (78)

1.27.1 Lenticular Scheme

1.27.1.1 Characteristic

The P343/P344/P345 pole slipping characteristic consists of three parts as shown in the R/X diagram below. The first part is the lenticular (lens) characteristic. The second is a straight line referred to as the blinder that bisects the lens and divides the impedance plane into the left and right halves. The third is a reactance line which is perpendicular to the blinder.

The inclination of the lens and the blinder, θ, is determined by the angle of the total system impedance. The equivalent impedance of the system and the step-up transformer determines the forward reach of the lens, Z_A, whereas the generator's transient reactance determines the reverse reach Z_B. The width of the lens is varied by the setting of the angle α.

A reactance line, perpendicular to the axis of the lens, is used to distinguish whether the impedance center of the swing is located in the power system or in the generator. It is set by the value of Zc along the axis of the lens, as shown in the following diagram. The reactance line splits the lens into Zone 1 (lens below the line) and Zone 2 (all of the lens).

For the pole slipping protection element the minimum operating current is 2% In and the minimum voltage is 1 V for 100/120 and 4 V for 380/480 V ratings. The pole slipping protection operates from the IA and VA current and voltage inputs to the relay.

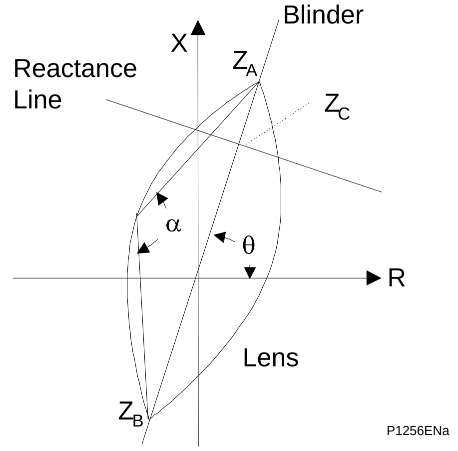


Figure 67 - Pole slipping protection using blinder and lenticular characteristic

1.27.1.2 Generating and Motoring Modes

When a generator is out of step with the system, the impedance locus is expected to traverse from right to left across the lens and the blinder. However, if the generator is running as a motor, as in the pumping mode of a pump storage generator, the impedance locus is expected to swing from the left to the right. A setting is provided to determine whether the protection operates in a generating mode or in a motoring mode or both.

If the protection is running in the generating mode, the impedance is expected to be at the right hand side of the lens under normal load conditions. During a pole slip the impedance locus traverses across the right half and the left half of the lens. The minimum time spent in each half of the lens can be set with timers T1 for the right hand side and T2 for the left hand side. The relay registers a pole slipping cycle when the locus finally leaves the lens at the opposite end.

If the protection is running in the motoring mode, the impedance is expected to be at the left hand side of the lens under normal load conditions. During a pole slip the impedance locus traverses across the left half and the right half of the lens, again spending at least the time T1 and T2 respectively in each half and leaves the lens at the opposite end.

1.27.2 Pole Slipping Protection Operation

The pole slipping protection algorithm is executed 4 times per power system cycle to obtain accurate timing of the impedance locus traversing the lens.

1.27.2.1 State Machine

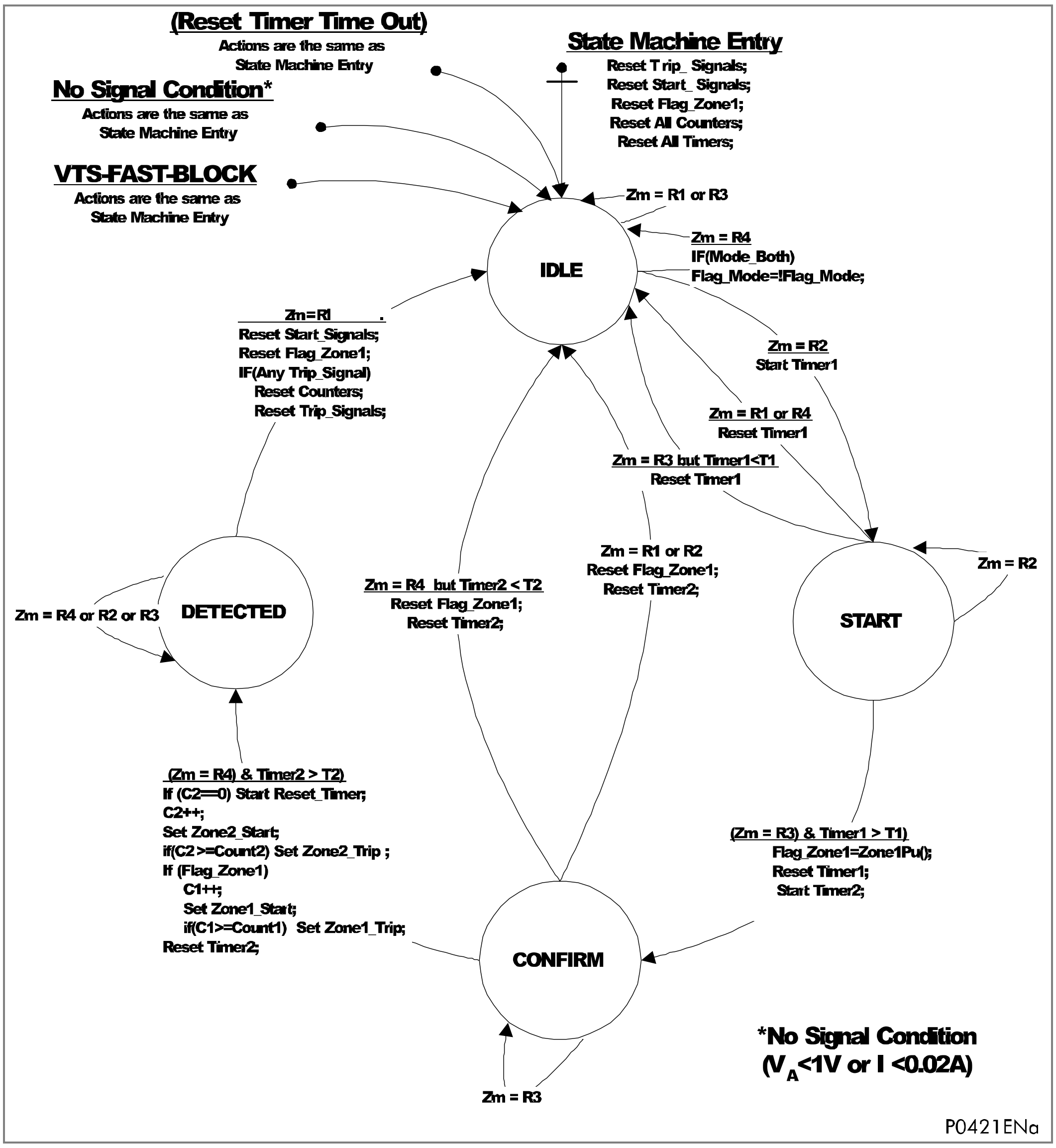


Figure 68 - State machine

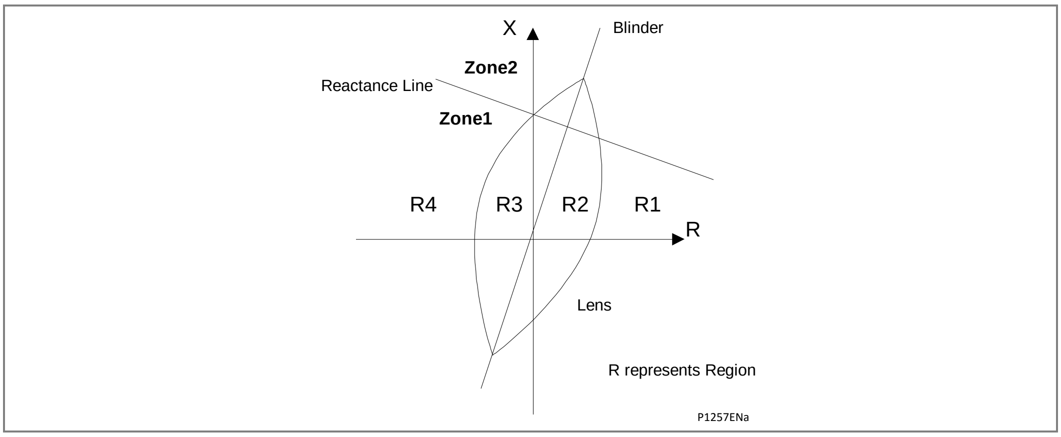


Figure 69 - Regions and zones definition (generating mode)

Note	*The regions shown in the Regions and zones definition (generating mode) diagram are independent of the reactance line although it is shown in the same diagram (zones are independent of the lens and the blinder).*

To track the impedance locus under a pole slipping condition, a 'State Machine' approach is adopted. There are 4 states 'Idle', 'Start', 'Confirm' and 'Detected' used to describe the movement of the impedance locus. Each state has one entrance and one or several exit terminals depending on the state. Exit terminals fall into two categories: 'normal exit' and 'abnormal exit'. There is only one 'normal exit' which leads to the next state when the impedance locus moves into the desired region. Unexpected impedance movement will result in a return to the 'Idle' State or will be ignored depending on where the impedance stays.

- Idle: This is the normal state when the measured impedance is the normal load impedance. The impedance locus of any pole slip should start from here. In this state the 'normal exit' is when the measured impedance moves from R1 to R2. Timer 1 that is used to time the duration of the impedance locus remaining in R2 is started when this change is detected.

  If the impedance locus moves to R4 and 'Both' is selected in the 'Mode' setting, a flag (Flag_Mode) indicating the generator operating mode is toggled to indicate 'Motoring'. Note, this does not cause a state transition, refer to the *Generating and Motoring Mode* section for details about the 'Flag_Mode'.

  In this state impedance locus changes to R3 will be ignored.
- Start: This is the state when the impedance locus stays inside R2. Normal exit is taken only if the impedance has stayed in R2 longer than the T1 time delay and moves to R3. Three actions are carried out along with this transition: check the operating status of the reactance line, start Timer 2 and reset Timer 1. The purpose of checking the operating status of the reactance line at this point is to decide whether the pole slip belongs to Zone1 or Zone2. A flag (Flag_Zone1) is latched if Zone1 picks up, which is used later on to differentiate whether counters are incremented for pole slips in zone1 or zone2. Theoretically, this flag is generated at the point where the impedance locus intersects the blinder, which is called the electrical center. Timer2 is used to time the duration of the impedance locus remaining in R3;

  If the impedance moves to R1 or R4 or moves to R3 but stays in R2 less than T1, the state machine will be reset to the 'Idle' state. Timer 1 is reset when the impedance leaves R2 via these abnormal exits. Besides pole slipping, a stable power swing or fault occurrence could enter this state as well. The state machine is designed to differentiate these conditions.

- Confirm: This state is reached when the impedance has crossed the blinder and arrived at Region3. Further confirmation is required to see if the impedance stays for at least time T2 and is bound to leave for R4. Otherwise, an abnormal exit will reset the state machine to the 'Idle' state. Actions on abnormal transition include resetting Flag_Zone1 and Timer 2.

Note	*As soon as the impedance locus leaves the lens through the normal exit counters of different zones will be updated, depending on the Flag_Zone1 and if the pole slip has completed the pre-set slip cycles setting a trip signal is given. If Flag_Zone1 is set then the Zone 1 counter (C1) will be incremented. Zone 2 is the backup pole slipping stage and so all pole slips increment the Zone2 counter (C2).*

  The Reset_Timer and reset Timer 2 are started when the normal transition occurs. The Reset_Timer is started only when the first pole slip is detected and will be reset in its time delay (see Reset_Timer time out actions in the state machine diagram).
- Detected: This is the stage where the impedance locus has to complete its full cycle although the counter is updated in the previous confirm stage. Abnormal movements of the impedance locus in this stage will be ignored and this state is kept until the impedance moves to R1 indicating completion of a pole slip cycle. If a trip signal has not been given for this pole slip, only the Start_Signals and Flag_Zone1 are reset in preparation for the next pole slip cycle. However, if a trip signal has been issued, then the Trip_Signals and the counters are both reset.

In general, once the measured impedance has traversed all the 'States' in the normal exit sequence, a pole slip is confirmed. For a stable power swing or fault condition the measured impedance will not satisfy all the exit transition criteria.

The 'State Machine' diagram has been simplified to present an overview of how to detect pole slipping. There are also several supporting protection functions which are explained in these sections.

1.27.2.2 Protection Functions and Logic Structure

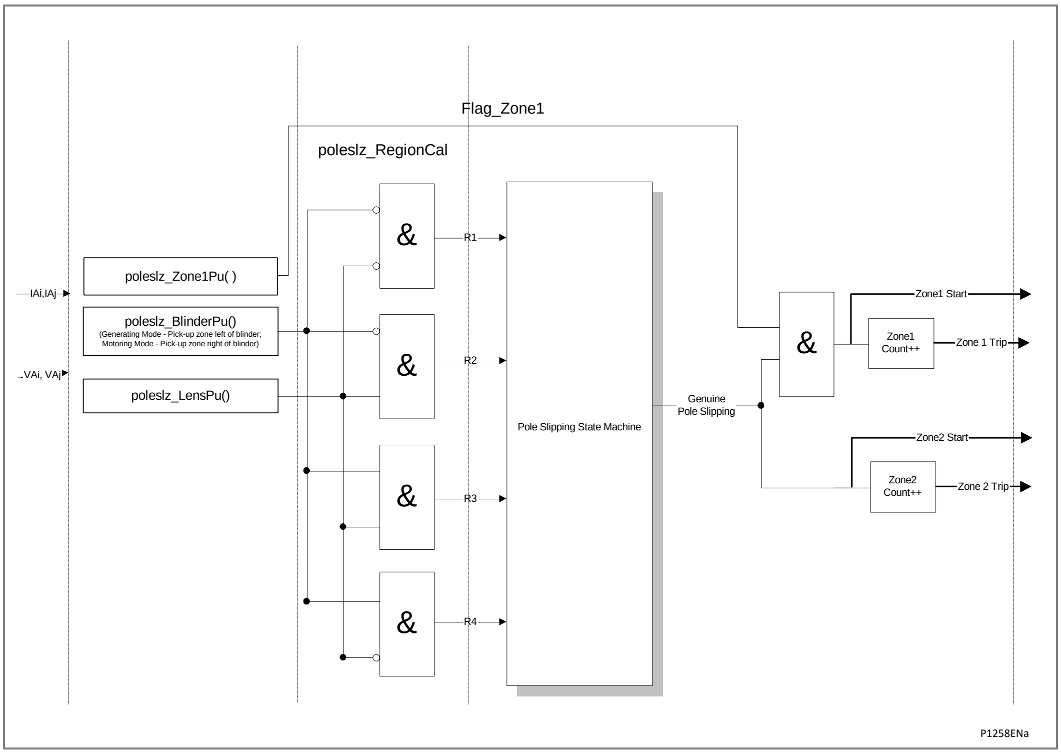


Figure 70 - Logic structure of pole slipping module

There are several protection functions called in sequence in the pole slipping detection, as shown in the above diagram, they are:

- poleslz_Zone1Pu
- poleslz_LensPu
- poleslz_BlinderPu
- poleslz_RegionCal

Function poleslz_Zone1Pu(), poleslz_LensPu() and Poleslz_BlinderPu() calculate whether the Reactance Line, Lens and Blinder characteristics have picked up respectively.

At the end of each function, DDBs associated with each characteristic are mapped according to the elements operating status. Outputs from poleslz_LensPu() and Poleslz_BlinderPu() feed into the poleslz_RegionCal() to determine in which 'Region' the locus is present. After the region and zone have been determined the state machine can be evaluated.

For the purpose of discriminating the pole slipping zone, Zone1 or Zone2, it is important to check the result of poleslz_Zone1Pu() when the impedance locus leaves the 'Start' state by the 'normal exit'. A flag is latched if Zone1 picks up, which is used to identify the pole slipping zone later on.

1.27.2.3 Motoring Mode

When the 'pole slip mode' setting is set to 'motoring' the protection algorithm is switched to motoring mode. Motoring mode is essentially the same for generating mode except that the pick-up zone for the blinder is changed from the left hand side to the right hand side, as shown in the following diagram. This requires changes to the blinder algorithm in poleslz_BlinderPu().

This automatically changes the region definition on the impedance plane. For example, under normal motoring conditions, both the blinder, which picks up from the left hand side for motoring, and the lens will not be picked up. Therefore the poleslz_RegionCal() will output a region number R1.

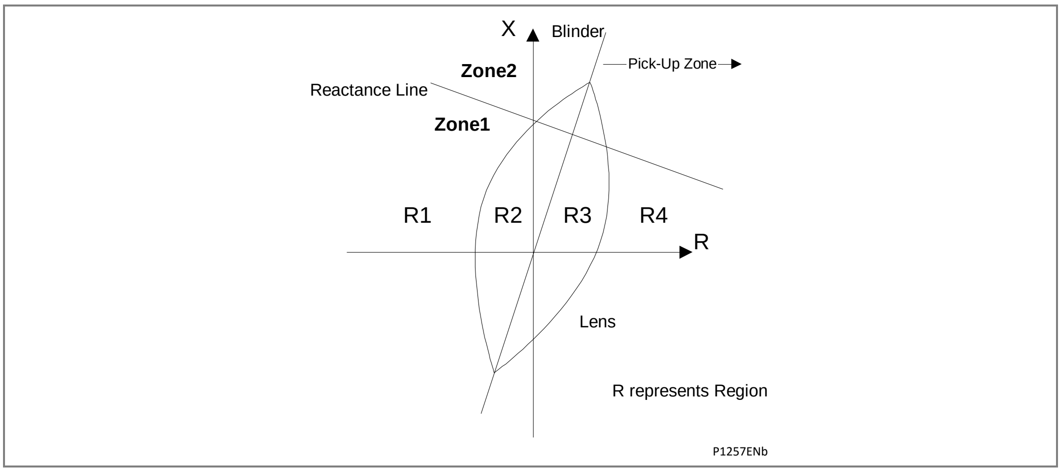


Figure 71 - Regions and zones definition (motoring mode)

1.27.2.4 Generating and Motoring Mode

For a pump storage generator, its operation can switch from generating mode to motoring mode and vice versa. Therefore, a facility is provided for the protection to detect the normal running mode of the machine (generating or motoring) and to perform pole slipping detection in either mode.

This facility is enabled when the **Pole Slip Mode** setting is set to **Both**.

Also, when a generator is running at low load, <30% load, due to the presence of heavy system damping during a fault the generator can slow down and result in a motor like slip (negative slip). To detect pole slips for this condition then the 'pole slip mode' should be set to 'Both'.

In the state machine, a flag called 'Flag_Mode' is used to deal with the mode change. During the initialization, the flag is set to 'generating', with the pick up zone of the blinder on the left-hand side. If the impedance traverses the blinder from R1 to R4 in the 'Idle' state, the 'Flag_Mode' is toggled to 'Motoring'. This causes the blinder pick-up zone to change from the left-hand side to right-hand side, therefore automatically redefining the regions numbering on the impedance plane, as discussed previously. Subsequent crossing of the blinder from R1 to R4 in the 'Idle' mode will cause the 'Flag_Mode' to toggle, therefore tracking the normal running operation of the pump storage generator, irrespective of whether it is in generating or motoring mode.

1.27.2.5 DDB Output

Apart from the Zone1 and Zone2 start and trip signals, each measuring element also outputs its 'status' onto the DDB. These signals can be used during commissioning testing to determine the shape and the accuracy of the characteristics. The pole slipping Z1 and Z2 protection starts are mapped internally to the ANY START DDB signal – DDB 992.

DDB name	Description
DDB 866 PSlipz Z1 Trip	Pole slipping tripped in Zone1
DDB 867 PSlipz Z2 Trip	Pole slipping tripped in Zone2
DDB 1122 PSlipz Z1 Start	Pole slipping detected in Zone1
DDB 1123 PSlipz Z2 Start	Pole slipping detected in Zone2
DDB 1124 PSlipz LensStart	Measured impedance is within the Lens
DDB 1125 Pslipz BlindStrt	Impedance lies left hand side of Blinder
DDB 1126 PSlipz ReactStrt	Impedance lies in Zone 1 distinguished by Reactance line

Table 11 - Pole slipping protection DDBs

1.28 Generator Thermal Overload Protection (49G)

1.28.1 Introduction

The physical and electrical complexity of generator construction results in a complex thermal relationship. Therefore it is not possible to create an accurate mathematical model of the true thermal characteristics of the machine.

However, if a generator is considered to be a homogeneous body, developing heat internally at a constant rate and dissipating heat at a rate directly proportional to its temperature rise, it can be shown that the temperature at any instant is given by:

$$T = T_{max} (1-e^{-t/\tau})$$

Where:

T_{max} = final steady state temperature

τ = heating time constant

This assumes a thermal equilibrium in the form:

Heat developed = Heat stored + Heat dissipated

Temperature rise is proportional to the current squared:

$$T = K I_R^2 (1-e^{-t/\tau})$$

$$T = T_{max} = K I_R^2 \text{ if } t = \infty$$

Where:

IR = the continuous current level which would produce a temperature T_{max} in the generator

For an overload current of 'I' the temperature is given by:

$$T = KI^2 (1-e^{-t/\tau})$$

For a machine not to exceed T_{max}, the rated temperature, then the time 't' for which the machine can withstand the current 'I' can be shown to be given by:

$$T_{max} = KI_R^2 = KI^2 (1-e^{-t/\tau})$$

$$t = \tau. \text{ Loge } (1/(1-(I_R/I)^2))$$

An overload protection element should therefore satisfy the above relationship. The value of I_R may be the full load current or a percentage of it depending on the design.

As previously stated it is an oversimplification to regard a generator as an homogeneous body. The temperature rise of different parts or even of various points in the same part may be very uneven. However, it is reasonable to consider that the current-time relationship follows an inverse characteristic. A more accurate representation of the thermal state of the machine can be obtained through the use of temperature monitoring devices (RTDs) which target specific areas. Also, for short time overloads the application of RTDs and overcurrent protection can provide better protection. Note, that the thermal model does not compensate for the effects of ambient temperature change. So if there is an unusually high ambient temperature or if the machine cooling is blocked RTDs will also provide better protection.

1.28.2 Thermal Replica

The P342/P343/P344/P345 relay models the time-current thermal characteristic of a generator by internally generating a thermal replica of the machine. The thermal overload protection can be selectively enabled or disabled. The positive and negative sequence components of the generator current are measured independently and are combined together to form an equivalent current, I_{eq}, which is supplied to the replica circuit. The heating effect in the thermal replica is produced by I_{eq}^2 and therefore takes into account the heating effect due to both positive and negative sequence components of current.

Unbalanced phase currents will cause additional rotor heating that may not be accounted for by some thermal protection relays based on the measured current only. Unbalanced loading results in the flow of positive and negative sequence current components. Load unbalance can arise as a result of single-phase loading, non-linear loads (involving power electronics or arc furnaces, etc.), uncleared or repetitive asymmetric faults, fuse operation, single-pole tripping and reclosing on transmission systems, broken overhead line conductors and asymmetric failures of switching devices. Any negative phase sequence component of stator current will set up a reverse-rotating component of stator flux that passes the rotor at twice synchronous speed. Such a flux component will induce double frequency eddy currents in the rotor, which can cause overheating of the rotor body, main rotor windings, damper windings etc. This extra heating is not accounted for in the thermal limit curves supplied by the generator manufacturer as these curves assume positive sequence currents only that come from a perfectly balanced supply and generator design. The relay thermal model may be biased to reflect the additional heating that is caused by negative sequence current when the machine is running. This biasing is done by creating an equivalent heating current rather than simply using the phase current. The M factor is a constant that relates negative sequence rotor resistance to positive sequence rotor resistance. If an M factor of 0 is used the unbalance biasing is disabled and the overload curve will time out against the measured generator positive sequence current.

Note	*The relay also includes a negative sequence overcurrent protection function based on I_2^2t specifically for thermal protection of the rotor.*

The equivalent current for operation of the overload protection is in accordance with the following expression:

$$I_{eq} = \sqrt{(I_1^2 + MI_2^2)}$$

Where:

I1 = Positive sequence current

I2 = Negative sequence current

M = A user settable constant proportional to the thermal capacity of the machine

As previously described, the temperature of a generator will rise exponentially with increasing current. Similarly, when the current decreases, the temperature also decreases in a similar manner. Therefore to achieve close sustained overload protection, the P342/P343/P344/P345 relay incorporates a wide range of thermal time constants for heating and cooling.

Furthermore, the thermal withstand capability of the generator is affected by heating in the winding prior to the overload. The thermal replica is designed to take account the extremes of zero pre-fault current, known as the ‘cold’ condition and the full rated pre-fault current, known as the ‘hot’ condition. With no pre-fault current the relay will be operating on the ‘cold curve’. When a generator is or has been running at full load prior to an overload the ‘hot curve’ is applicable. Therefore during normal operation the relay will be operating between these two limits.

The following equation is used to calculate the trip time for a given current. Note that the relay will trip at a value corresponding to 100% of its thermal state.

The thermal time characteristic is given by:

$$t = \tau \log_e (I_{eq}^2 - I_P^2)/(I_{eq}^2 - (\text{Thermal } I>)^2$$

Where:

t	=	Time to trip, following application of the overload current, I
τ	=	Heating time constant of the protected plant
I_{eq}	=	Equivalent current
Thermal I>	=	Relay setting current
I_P	=	Steady state pre-load current 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:

$$\exp(-t/\tau) = (\theta - 1)/(\theta - \theta_p)$$

$$t = \tau \log_e (\theta - \theta_p) / (\theta - 1)$$

Where:

θ = $I_{eq}^2/(\text{Thermal } I>)^2$

and

θp = $I_p^2/(\text{Thermal } I>)^2$

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

Note	*The thermal model does not compensate for the effects of ambient temperature change.*

t = $\tau.$ $\text{Log}_e ((K^2-A^2)/(K^2-1))$

t_{alarm} = $\tau.$ $\text{Log}_e ((K^2-A^2)/(K^2-(\text{Thermal Alarm}/100))$

Where:

K = I_{eq}/Thermal $I>$ (K^2 = Thermal state, θ)

A = I_P/Thermal $I>$ (A^2 = Pre-fault thermal state, θ_p)

Thermal Alarm = Thermal alarm setting, 20-80%

The Thermal state of the machine can be viewed in the **Thermal Overload** cell in the **MEASUREMENTS 3** column. The thermal state can be reset by selecting 'Yes' in the **Reset ThermalO/L** cell in **Measurements 3**. Alternatively the thermal state can be reset by energizing DDB 641 **Reset Gen Thermal** via the relay PSL.

A DDB signal **Gen Thermal Trip** is also available to indicate tripping of the element (DDB 945). A further DDB signal **Gen Thermal Alm** is generated from the thermal alarm stage (DDB 371). The state of the DDB signal can be programmed to be viewed in the **Monitor Bit x** cells of the **COMMISSION TESTS** column in the relay.

The functional block diagram for the thermal overload protection is shown here:

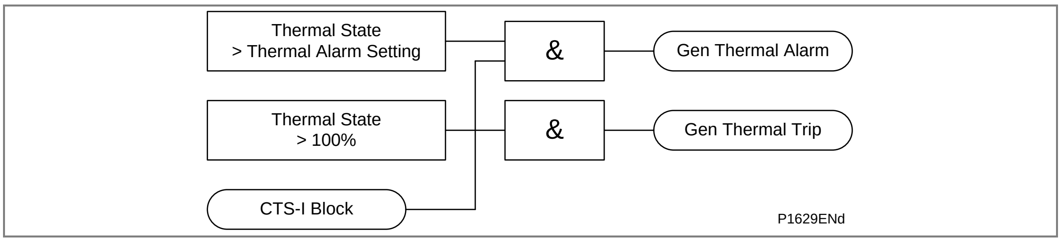


Figure 72 - Thermal overload protection logic diagram

1.29 Transformer Thermal Overload Protection (49T)

Transformer thermal overload protection is designed to protect the equipment from sustained overload that results in the transformer's thermal rating being exceeded. Thermal overload protection compliments the transformer overcurrent protection by allowing modest but transient overload conditions to occur, while tripping for sustained overloads that the overcurrent protection will not detect.

The thermal overload function is based on the IEEE Standard C57.91-1995. This function can be enabled or disabled in the setting or it can be blocked in the PSL. Two three-stage definite time-delayed trip elements based on hot spot or top oil temperature are available. A pre-trip alarm is offered in the tPre-trip Set setting. This alarm indicates that thermal overload will trip after the settable time if load level remains unchanged.

The monitor winding can be set to HV, LV or biased current. If the monitor winding is set to biased current an overall through loading picture of the transformer is provided.

To calculate the top oil and hot spot winding temperature, the relay takes into consideration the ratio of the ultimate load to the rated load. The rated load is determined by the IB and the rating settings.
When the monitored winding is set as the HV winding, the rated load is calculated using the HV Rating and the IB settings.
When the monitored winding is set as the LV winding, the rated load is calculated using the LV Rating and the IB settings.
When the monitored winding is set as the biased current, the rated load is calculated using the REF Power S and the IB settings.
The ultimate load is the load that is actually being fed by the transformer.

The biased current used by the thermal protection is not the same as the biased current used by the differential protection. No vector correction or zero sequence filtering is taken into account. The thermal element uses the maximum phase biased current.

The thermal overload model is executed every power cycle. The thermal overload trip can be based on either hot spot temperature or top oil temperature, or both.

1.29.1 Inputs

Signal name	Description
IA-HV, IB-HV, IC-HV, IA-LV, IB-LV, IC-LV,	Phase current levels (raw samples). The currents required by the thermal overload element are the currents of the winding being monitored.
IA-bias, IB-bias, IC-bias	Bias currents
ΘTO	Measured top oil temperature
ΘA	Measured ambient temperature
Reset X thermal (DDB 649)	Reset thermal overload
Forced Air Cool (DDB 650)	If DDB 650 = 1 then cooling mode is Forced Air Cooling, if DDB 651 = 1 then cooling mode is Forced Oil Cooling, if DDB 650 and 651 = 1 then cooling mode is Forced Air Oil Cooling, if DDB 650 and 651 = 0 then cooling mode is Natural Cooling.
Forced Oil Cool (DDB 651)	As above

Table 12 – Transformer thermal overload inputs

1.29.2 Outputs

Signal name	Description
Top oil >1 start (DDB 1203)	Top oil first stage start
Top oil >2 start (DDB 1204)	Top oil second stage start
Top oil >3 start (DDB 1205)	Top oil third stage start
Top oil >1 trip (DDB 949)	Top oil first stage trip
Top oil >2 trip (DDB 950)	Top oil second stage trip
Top oil >3 trip (DDB 951)	Top oil third stage trip
Hot spot >1 start (DDB 1200)	Hot spot first stage start
Hot spot >2 start (DDB 1201)	Hot spot second stage start
Hot spot >3 start (DDB 1202)	Hot spot third stage start
Hot spot >1 trip (DDB 946)	Hot spot first stage trip
Hot spot >2 trip (DDB 947)	Hot spot second stage trip
Hot spot >3 trip (DDB 948)	Hot spot third stage trip
XThermPretrp Alm (DDB 401)	Tol Pretrip Alm
Ambient T	Ambient temperature measurement
Top oil T	Top oil temperature measurement
Hot spot T	Hot spot temperature measurement
TOL Pre-trip left	Pre-trip time left measurement

Table 13 - VTS outputs

1.29.3 Operation

The thermal overload protection in the relay uses the thermal model given by the equations for hot spot and top oil temperatures. A discrete time thermal replica model is implemented and it is described by the equations for $\Delta\Theta_{TOn}$ and $\Delta\Theta_{Hn}$.

If the top oil temperature is not available as a measured input quantity, it is calculated every cycle by the following equation:

$$\Theta_{TO} = \Theta_A + \Delta\Theta_{TO}$$

Where:

Θ_{TO} = Top oil temperature
Θ_A = Ambient temperature
$\Delta\Theta_{TO}$ = Top oil rise over ambient temperature due to a step load change

The ambient temperature can be measured directly or it can be set in the Average Amb T setting. $\Delta\Theta_{TO}$ is given by the following exponential expression containing an oil time constant:

$$\Delta\Theta_{TOn} = \left(\Delta\Theta_{TO,U} - \Delta\Theta_{TO,n-1}\right)\cdot\left(1 - e^{-\left(\frac{\Delta t}{\tau_{TO}}\right)}\right) + \Delta\Theta_{TO,n-1}$$

Where:

$\Delta\Theta_{TO,U}$ = ultimate top oil rise over ambient temperature for load L
$\Delta\Theta_{TO,n-1}$ = the previous top oil rise over ambient temperature
Δ_t = elapsed time between the ultimate top oil rise and the initial top oil rise
τ_{TO} = oil time constant of the transformer for any load L between the ultimate top oil rise and the initial top oil rise. This parameter is set by the user.

By using power series, top oil rise, $\Delta\Theta_{TOn}$, can be approximated as shown below:

$$\Delta\Theta_{TOn} = \left(\Delta\Theta_{TO,U} - \Delta\Theta_{TO,n-1}\right)\cdot\left(\frac{\Delta t}{\tau_{TO}}\right) + \Delta\Theta_{TO,n-1}$$

The ultimate top oil rise is given by the following equation:

$$\Delta\Theta_{TO,U} = \Delta\Theta_{TO,R}\cdot\left[\frac{K_u^2 R + 1}{R+1}\right]^n$$

Where:

K^u= the ratio of ultimate load L to rated load

R = the ratio of the load loss at rated load to no load loss. This parameter is set by the user.

n = Oil exponent. This parameter is set by the user.

$\Delta\Theta_{TO,R}$ = top oil rise over ambient temperature at rated load. This parameter is set by the user.

The hot spot temperature can only be obtained by calculation. This equation is used to calculate the hot spot temperature every cycle:

$$\Theta_H = \Theta_{TO} + \Delta\Theta_H$$

Where:

Θ_H = Hot spot (winding) temperature

Θ_{TO} = Top oil temperature

$\Delta\Theta_H$ = Hot spot rise above top oil temperature

The hot spot temperature rise over top oil temperature, $\Delta\Theta_H$, is given by:

$$\Theta_H = \Theta_{TO} + \Delta\Theta_H$$

Where:

$\Delta\Theta_{H,U}$ = ultimate hot spot rise over top oil temperature for load L

$\Delta\Theta_{H,n-1}$ = previous hot spot rise over top oil temperature

Δt = elapsed time between the ultimate hot spot rise and the initial hot spot rise. Δt is one cycle.

τ_W = winding time constant at hot spot location. This parameter is set by the user.

By using power series, hot spot temperature rise, $\Delta\Theta_{Hn}$, can be approximated as shown below:

$$\Delta\Theta_{Hn} = \left(\Delta\Theta_{H,U} - \Delta\Theta_{H,n-1}\right)\cdot\left(\frac{\Delta t}{\tau_w}\right) + \Delta\Theta_{H,n-1}$$

The ultimate hot spot rise over top oil is given by:

$$\Delta\Theta_{H,U} = \Delta\Theta_{H,R}\cdot K_U{}^{2m}$$

Where:

$\Delta\Theta_{H,R}$ = winding hottest spot rise over top oil temperature at rated load. This parameter is set by the user.

K_U = the ratio of ultimate load L to rated load

m = winding exponent. This parameter is set by the user.

The load current used in the calculations is the rms value. The rms current is calculated according to the following equation:

$$L_{rms} = \sqrt{\frac{L_1{}^2 + L_2{}^2 + \ldots + L_{24}{}^2}{24}}$$

Where L_n is the sample, there are 24 sample per cycle.

Hot spot temperature, Top oil temperature and ambient temperature are stored in non-volatile memory. These measurements are updated every power cycle. The thermal state can be reset to zero by any of the following:

- The **Reset X Thermal** cell under the **MEASUREMENT 4** heading on the front panel
- A remote communications interface command
- A status input state change.

The top oil temperature, hot spot temperature, ambient temperature and pre-trip time left are available as a measured value in the **Measurement 4** column.

If a more accurate representation of the thermal state of the transformer is required, the use of temperature monitoring devices (RTDs or CLIO) which target specific areas is recommended. Also, for short time overloads the application of RTDs/CLIO and overcurrent protection can provide better protection.

1.30 Loss of Life Statistics

Deterioration of insulation is a time function of temperature. Since the temperature distribution is not uniform, the part that is operating at the highest temperature undergoes the greatest deterioration. Therefore the hot spot temperature is considered in loss of life statistics. The loss of life model is executed every cycle.

Two one-stage definite time delay alarm based on aging acceleration factor (F_{AA}) or loss of life (LOL) are available.

A reset command is provided to allow the user to reset the calculated parameters: LOL status, LOL aging factor (F_{AA}), mean aging factor ($F_{AA.m}$), rate of loss of life (Rate of LOL), residual life at F_{AAm} (Lres at $F_{AA,m}$), residual life at designed (Lres at designed).

1.30.1 Inputs

Signal name	Description
IA-HV, IB-HV, IC-HV, IA-LV, IB-LV, IC-LV,	Phase current levels (raw samples). The currents required by the thermal overload element are the currents of the winding being monitored.
IA-bias, IB-bias, IC-bias	Bias currents
Θ_H	Calculated hot spot temperature
Reset LOL	Reset loss of life

Table 14 - Loss of life inputs

1.30.2 Outputs

Signal name	Description
FAA Alarm	Aging acceleration factor alarm
Loss of Life Alm	Loss of life alarm
LOL status	Accumulated loss of life (LOL) measurement in hrs
Lres at designed	Residual life at reference hottest spot temperature
Rate of LOL	Rate of loss of life (ROLOL) measurement in %
LOL aging factor	Aging acceleration factor (F_{AA}) measurement
FAA,m	Mean aging acceleration factor ($F_{AA,m}$) measurement
Lres at FAA,m	Residual life hours at $F_{AA,m}$ ($L_{res}(F_{AA,m})$) measurement

Table 15 - Loss of life outputs

1.30.3 Operation

As indicated in IEEE Std. C57.91-1995 the aging acceleration factor is the rate at which transformer insulation aging for a given hottest spot temperature is accelerated compared with the aging rate at a reference hottest spot temperature. For 65°C average winding rise transformers, the reference hottest spot temperature is 110°C. For 55°C average winding rise transformers, the reference hottest spot temperature is 95°C. For hottest spot temperatures in excess of the reference hottest spot temperature the aging acceleration factor is greater than 1. For hottest spot temperatures lower than the reference hottest spot temperature, the aging acceleration factor is less than 1.

The model used for loss of life statistics is given by the equations for LOL and F_{AA}. LOL is calculated every hour according to this formula:

$$LOL = L(\Theta_{H,r}) - L_{res}(\Theta_{H,r})$$

Where:

$L(\Theta_{H,r})$ = life hours at reference winding hottest-spot temperature. This parameter is set by the user.

$L_{res}(\Theta_{H,r})$ = residual life hours at reference winding hottest-spot temperature

The aging acceleration factor F_{AA} is calculated every cycle as follows:

$$F_{AA} = \frac{L(\Theta_{H,r})}{L(\Theta_H)} = \frac{e^{\left[A+\frac{B}{\Theta_{H,r}+273}\right]}}{e^{\left[A+\frac{B}{\Theta_H+273}\right]}} = e^{\left[\frac{B}{\Theta_{H,r}+273}-\frac{B}{\Theta_H+273}\right]}$$

If a 65°C average winding rise transformer is considered, the equation for F_{AA} is:

$$F_{AA} = e^{\left[\frac{B}{383}-\frac{B}{\Theta_H+273}\right]}$$

If a 55°C average winding rise transformer is considered, the equation for F_{AA} is:

$$F_{AA} = e^{\left[\frac{B}{368}-\frac{B}{\Theta_H+273}\right]}$$

Where:

$L(\Theta_H)$ = life hours at winding hottest-spot temperature

Θ_H = hottest-spot temperature as calculated in thermal overload protection

$\Theta_{H,r}$ = hottest-spot temperature at rated load.

B = constant B from life expectancy curve. This parameter is set by the user. IEEE Std. C57.91-1995 recommends a B value of 15000.

The residual life hours at reference hottest-spot temperature is updated every hour as follows:

$$L_{res}(\Theta_{H,r}) = L_{res,p}(\Theta_{H,r}) - \frac{\sum_{i=1}^{3600} F_{AA,i}(\Theta_H)}{3600}$$

Where:

$L_{res,p}(\Theta H,r)$ = residual life hours at reference temperature one hour ago

$F_{AA,i}(\Theta H)$ = Mean aging acceleration factor, as calculated above. It is calculated every second.

The accumulated Loss Of Life (LOL) will be updated in non-volatile memory once per hour. It will be possible to reset and set a new loss of life figure, in the event that a relay is applied in a new location with a pre-aged resident transformer.

The Rate Of Loss Of Life (ROLOL) in percent per day is given as follows, and it is updated every day:

$$ROLOL = \frac{24}{L(\Theta_{H,r})} \cdot F_{AA,m}(\Theta_H) \cdot 100\%$$

The mean aging acceleration factor, $F_{AA,m}$, is updated per day, and it is given by:

$$F_{AA,m} = \frac{\sum_{n=1}^{N} F_{AAn} \cdot \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} = \frac{\sum_{n=1}^{N} F_{AAn}}{N}$$

Where:

F_{AAn} is calculated every cycle

Δtn = 1cycle

$F_{AA,\ m}$ states the latest one-day statistics of F_{AA}. When the relay is energized for the first time, $F_{AA,\ m}$ default value is 1.

The residual life in hours at $F_{AA,m}$ is updated per day, and it is given by:

$$L_{res}(F_{AA,m}) = \frac{L_{res}(\Theta_{H,r})}{F_{AA,m}}$$

1.31 Through Fault Monitoring

Through faults are a major cause of transformer damage and failure. Both the insulation and the mechanical effects of fault currents are considered. The through fault current monitoring function in the relay gives the fault current level, the duration of the faulty condition, the date and time for each through fault. An I^2t calculation based on the recorded time duration and maximum current is performed for each phase. Cumulative stored calculations for each phase are monitored so that the user may schedule the transformer maintenance based on this data. This may also justify possible system enhancement to reduce through fault level.

One stage alarm is available for through-fault monitoring. The alarm is issued if the maximum cumulative I^2t in the three phases exceeds **the TF I2t> Alarm** setting. A through fault event is recorded if any of the phase currents is bigger than the TF I> Trigger setting. Set **TF I> Trigge**r greater than the overload capability of the transformer. According to IEEE Std. C57.109-1993, values of 3.5 or less times normal base current may result from overloads rather than faults. IEEE Std. C57.91-1995, states that the suggested limit of load for loading above the nameplate of a distribution transformer with 65°C rise is 300% of rated load during short-time loading (0.5 hours or less). On the other hand, the suggested limit of load for loading above the nameplate of a power transformer with 65°C rise is 200% maximum.

To set **TF I2t> Alarm** consider the recommendations given in IEEE Std. C57.109-1993 for transformers built beginning in the early 1970s. Consult the transformer manufacturer regarding the short circuit withstand capabilities for transformers built prior the early 1970s.

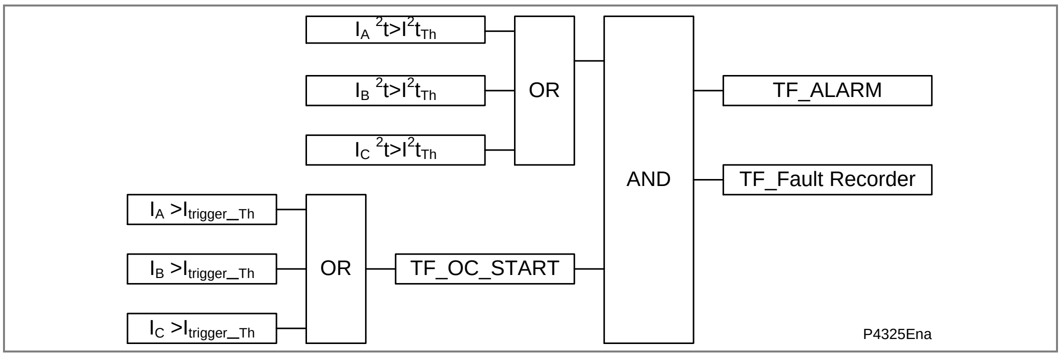


Figure 73 - Through fault monitoring logic

1.31.1 Inputs

Signal name	Description
IA-HV, IB-HV, IC-HV or IA-LV, IB-LV, IC-LV	Phase current levels (Fourier magnitudes) of the selected winding

Table 16 - Through fault monitoring inputs

1.31.2 Outputs

Signal name	Description
IA peak, IB peak, IC peak	Peak current in the monitor winding in a per phase basis
I2t phase A, I2t phase B, I2t phase C	I2t magnitude in the monitor winding in a per phase basis
Thru fault alarm (DDB399)	Through fault monitoring alarm

Table 17 - Through fault monitoring ouputs

IA peak, IB peak, IC peak, I2t phase A, I2t phase B and I2t phase C are given in the VIEW RECORDS menu in the setting file.

1.32 Circuit Breaker Failure Protection (50BF)

The circuit breaker failure 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 (PSL)). This contact is used to backtrip upstream switchgear, generally tripping all infeeds connected to the same busbar section.
- A re-tripping scheme, plus delayed back-tripping. 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 back-trip may be issued following an additional time delay. The back-trip uses **CB Fail 2 Timer**, which is also started at the instant of the initial protection element trip.

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 PSL.

Resetting of the CBF is possible from a breaker open indication (from the relay's pole dead logic) or from a protection reset. In these cases, resetting is only allowed provided the undercurrent elements have also reset. The resetting options are summarized in this table:

Initiation (menu selectable)	CB fail timer reset mechanism
Current based protection (e.g. 50/51/46/21/87..)	The resetting mechanism is fixed. [IA< operates] & [IB< operates] & [IC< operates] & [IN< operates]
Sensitive earth fault element	The resetting mechanism is fixed. [ISEF< operates]
Non-current based protection (e.g. 27/59/81/32L..)	Three 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]
External protection	Three 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]

Table 18 - CB fail timer reset mechanisms

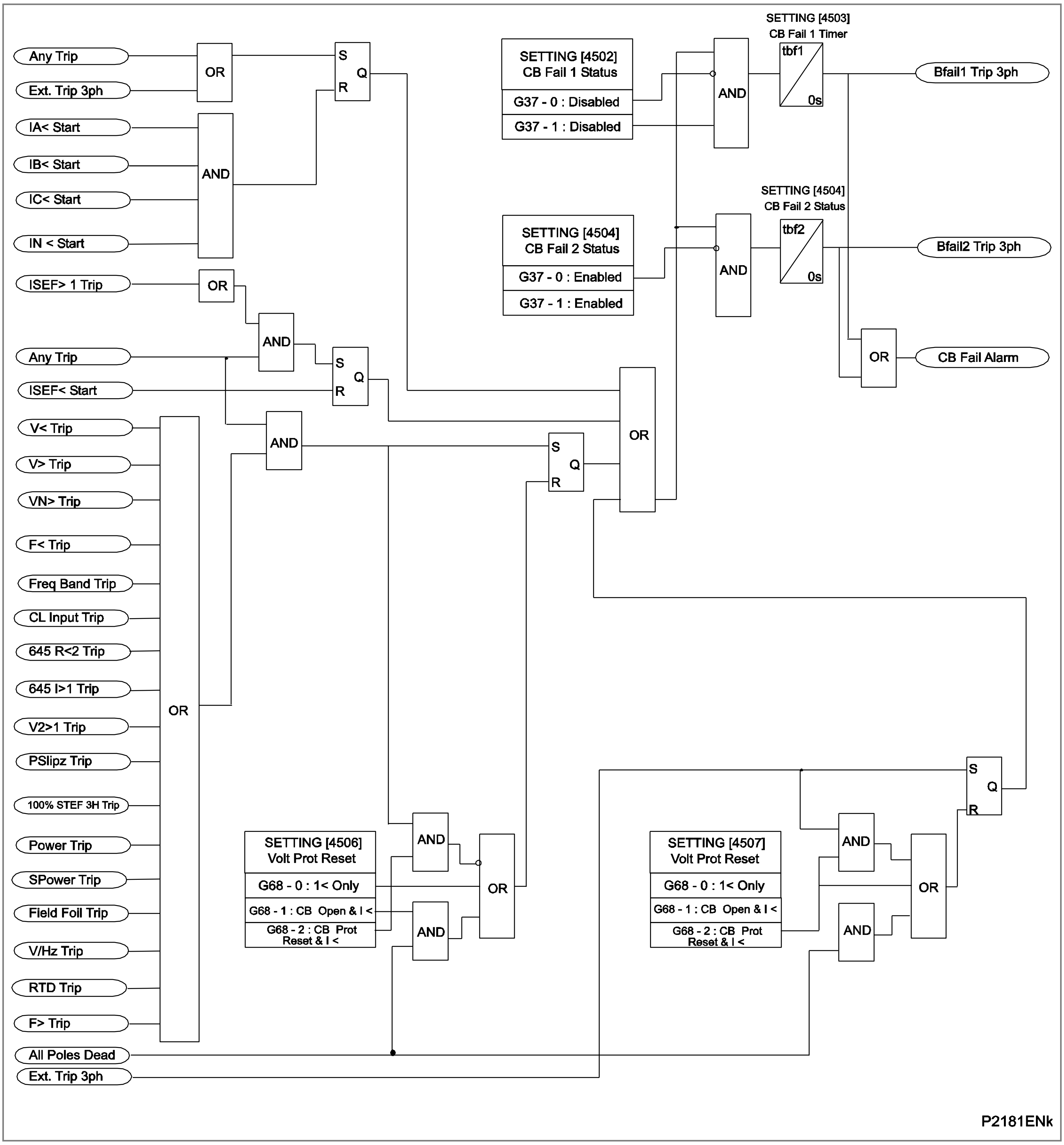


Figure 74 - CB fail logic

1.33 Current Loop Inputs and Outputs

1.33.1 Current Loop Inputs

Four analog (or current loop) inputs are provided for transducers with ranges of 0 - 1 mA, 0 - 10 mA, 0 - 20 mA or 4 - 20 mA. The analog inputs can be used for various transducers such as vibration monitors, tachometers and pressure transducers. Associated with each input there are two protection stages, one for alarm and one for trip. Each stage can be individually enabled or disabled and each stage has a definite time delay setting.

The Alarm and Trip stages can be set for operation when the input value falls below the Alarm/Trip threshold **Under** or when the input current is above the input value **Over**. The sample interval is nominally 50 ms per input.

The relationship between the transducer measuring range and the current input range is linear. The maximum and minimum settings correspond to the limits of the current input range. This relationship is shown in the *Relationship between the transducer measuring quantity and the current input range* diagram.

This diagram also shows the relationship between the measured current and the analog to digital conversion (ADC) count. The hardware design allows for over-ranging, with the maximum ADC count (4095 for a 12-bit ADC) corresponding to 1.0836 mA for the 0 - 1 mA range, and 22.7556 mA for the 0 - 10 mA, 0 - 20 mA and 4 - 20 mA ranges. The relay will therefore continue to measure and display values beyond the Maximum setting, within its numbering capability.

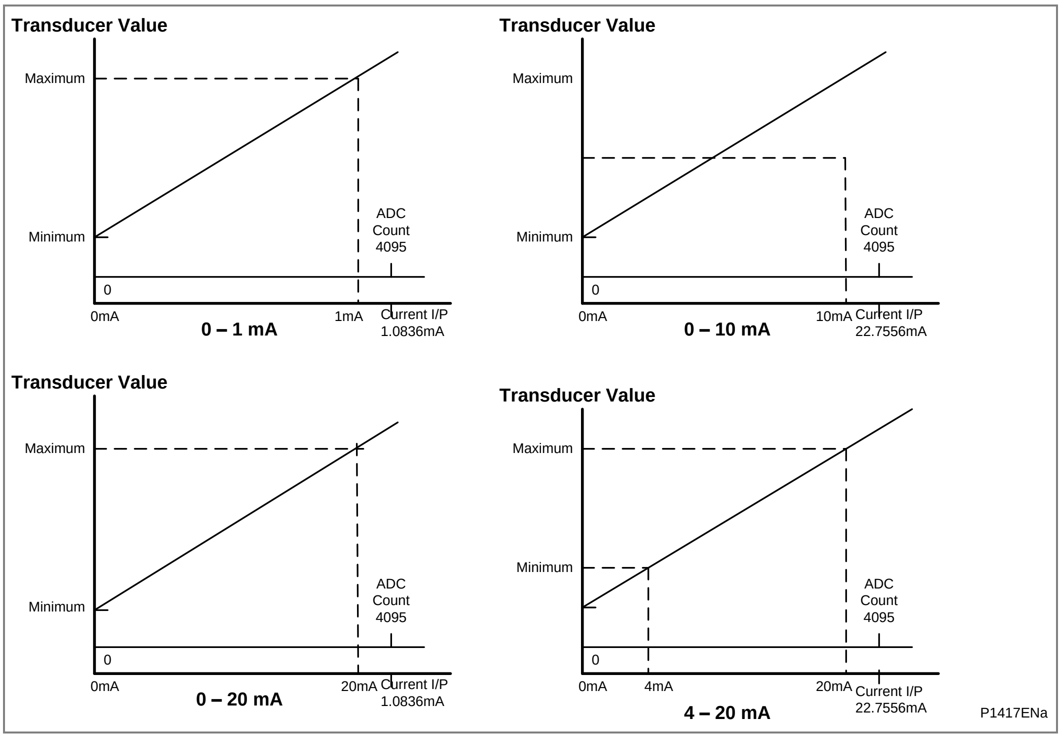


Figure 75 – Relationship between the Transducer measuring quantity and the current input range

Note	*If the Maximum is set less than the Minimum, the slopes of the graphs will be negative. This is because the mathematical relationship remains the same irrespective of how Maximum and Minimum are set, e.g., for 0 - 1 mA range, Maximum always corresponds to 1 mA and Minimum to 0 mA.*

Power-on diagnostics and continuous self-checking are provided for the hardware associated with the current loop inputs. When a failure is detected, the protection associated with all the current loop inputs is disabled and a single alarm signal (CL Card I/P Fail, DDB 384) is set and an alarm (CL Card I/P Fail) is raised. A maintenance record with an error code is also recorded with additional details about the type of failure.

For the 4 - 20 mA input range, a current level below 4 mA indicates that there is a fault with the transducer or the wiring. An instantaneous under current alarm element is available, with a setting range from 0 to 4 mA. This element controls an output signal (CLI1/2/3/4 I< Fail Alm., DDB 390-393) which can be mapped to a user defined alarm if required.

Hysteresis is implemented for each protection element. For **Over** protection, the drop-off/pick-up ratio is 95%, for 'Under' protection, the ratio is 105%.

A timer block input is available for each current loop input stage which will reset the CLI timers of the relevant stage if energized, (DDB 656-659). If a current loop input is blocked the protection and alarm timer stages and the 4 - 20 mA undercurrent alarm associated with that input are blocked. The blocking signals may be useful for blocking the current loop inputs when the CB is open for example.

DDB signals are available to indicate starting an operation of the alarm and trip stages of the current loop inputs, (CLI1/2/3/4 Alarm Start: DDB 1232-1235, CLI1/2/3/4 Trip Start: DDB 1236-1239, CL Input 1/2/3/4 Alarm: DDB 386-389, CLI Input1/2/3/4 Trip: DDB 987-990). 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.

The current loop input starts are mapped internally to the ANY START DDB signal – DDB 992.

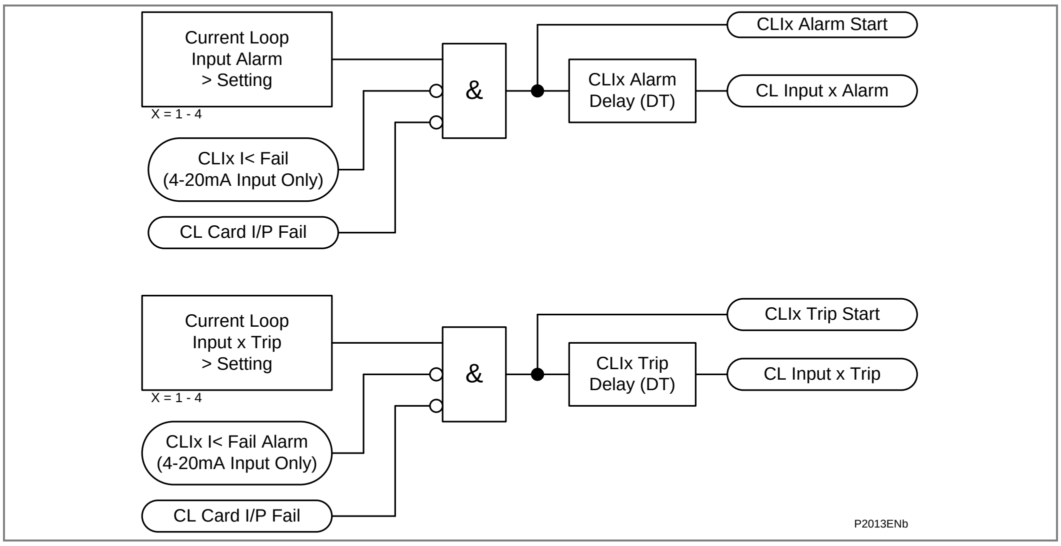


Figure 76 - Current loop input logic diagram

1.33.2 Current Loop Output

Four analog current outputs are provided with ranges of 0 - 1 mA, 0 - 10 mA, 0 - 20 mA or 4 - 20 mA which can alleviate the need for separate transducers. These may be used to feed standard moving coil ammeters for analog indication of certain measured quantities or into a SCADA using an existing analog RTU.

The CLIO output conversion task runs every 50 ms and the refresh interval for the output measurements is nominally 50 ms. The exceptions are marked with an asterisk in the table of current loop output parameters below. Those exceptional measurements are updated once every second.

The user can set the measuring range for each analog output. The range limits are defined by the Maximum and Minimum settings.

This allows the user to “zoom in” and monitor a restricted range of the measurements with the desired resolution. For voltage, current and power quantities, these settings can be set in either primary or secondary quantities, depending on the **CLO1/2/3/4 Set Values** - **Primary/Secondary** setting associated with each current loop output.

The output current of each analog output is linearly scaled to its range limits, as defined by the Maximum and Minimum settings. The relationship is shown in the *Relationship between the current output and the relay measurement* diagram.

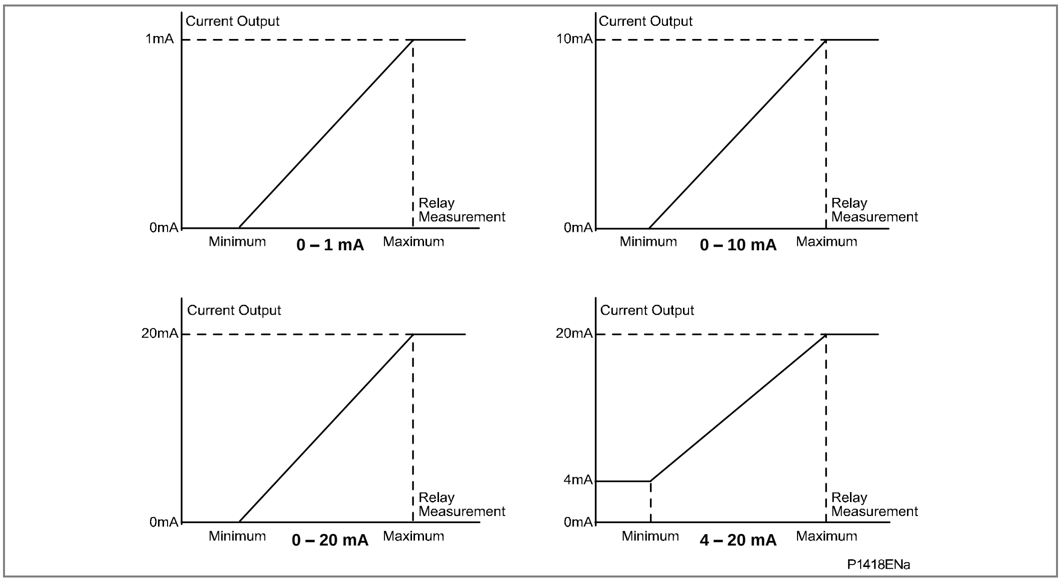


Figure 77 - Relationship between the current output and the relay measurement

Note	*If the Maximum is set less than the Minimum, the slopes of the graphs will be negative. This is because the mathematical relationship remains the same irrespective of how Maximum and Minimum are set, e.g., for 0 - 1 mA range, Maximum always corresponds to 1 mA and Minimum to 0 mA.*

The relay transducers are of the current output type. This means that the correct value of output will be maintained over the load range specified. The range of load resistance varies a great deal, depending on the design and the value of output current. Transducers with a full scale output of 10 mA will normally feed any load up to a value of 1000 Ω (compliance voltage of 10 V). This equates to a cable length of 15 km (approximately) for lightweight cable (1/0.6 mm cable). A screened cable earthed at one end only is recommended to reduce interference on the output current signal. The table below gives typical cable impedances/km for common cables. The compliance voltage dictates the maximum load that can be fed by a transducer output. Therefore, the 20 mA output will be restricted to a maximum load of 500 Ω approximately.

Cable	1/0.6 mm	1/0.85 mm	1/1.38 mm
CSA (mm2)	0.28	0.57	1.50
R (Ω/km)	65.52	32.65	12.38

Table 19 - Cable resistances

The receiving equipment, whether it be a simple moving-coil (DC milliamp meter) instrument or a remote terminal unit forming part of a SCADA system, can be connected at any point in the output loop and additional equipment can be installed at a later date (provided the compliance voltage is not exceeded) without any need for adjustment of the transducer output.

Where the output current range is used for control purposes, it is sometimes worthwhile to fit appropriately rated diodes, or Zener diodes, across the terminals of each of the units in the series loop to guard against the possibility of their internal circuitry becoming open circuit. In this way, a faulty unit in the loop does not cause all the indications to disappear because the constant current nature of the transducer output simply raises the voltage and continues to force the correct output signal round the loop.

Power-on diagnostics and continuous self-checking are provided for the hardware associated with the current loop outputs. When failure is detected, all the current loop output functions are disabled and a single alarm signal (CL Card O/P Fail, DDB 385) is set and an alarm (CL Card O/P Fail) is raised. A maintenance record with an error code is also recorded with additional details about the type of failure.

Current loop output parameters are shown in this table:

Current loop output parameter	Abbreviation	Units	Range	Step	Default min.	Default max.
Current Magnitude	IA Magnitude IB Magnitude IC Magnitude IN Measured Mag. (P342) IN-1 Measured Mag. (P343/P344/P345) IN-2 Measured Mag. (P343/P344/P345) IA Diff 2H (P343/P344/P345) IB Diff 2H(P343/P344/P345) IC Diff 2H(P343/P344/P345) IA Diff 5H (P343/P344/P345) IB Diff 5H(P343/P344/P345) IC Diff 5H(P343/P344/P345)	A	0 to 16A	0.01A	0A	1.2A
Sensitive Current Input Magnitude	I Sen Magnitude	A	0 to 2A	0.01A	0A	1.2A
Phase Sequence Current Components	I1 Magnitude I2 Magnitude I0 Magnitude	A	0 to 16A	0.01A	0A	1.2A
RMS Phase Currents	IA RMS* IB RMS* IC RMS*	A	0 to 16A	0.01A	0A	1.2A
P-P Voltage Magnitude	VAB Magnitude VBC Magnitude VCA Magnitude	V	0 to 200 V	0.1 V	0 V	140 V
P-N voltage Magnitude	VAN Magnitude VBN Magnitude VCN Magnitude	V	0 to 200 V	0.1 V	0 V	80 V
Neutral Voltage Magnitude	VN1 Measured Mag. VN Derived Mag. VN2 Measured Mag. (P344/P345)	V	0 to 200 V	0.1 V	0 V	80 V
3rd Harmonic Neutral Voltage	VN 3rd Harmonic	V	0 to 200 V	0.1 V	0 V	80 V

Current loop output parameter	Abbreviation	Units	Range	Step	Default min.	Default max.
Phase Sequence Voltage Components	V1 Magnitude* V2 Magnitude V0 Magnitude	V	0 to 200 V	0.1 V	0 V	80 V
RMS Phase Voltages	VAN RMS* VBN RMS* VCN RMS*	V	0 to 200 V	0.1 V	0 V	80 V
Frequency	Frequency	Hz	0 to 70 Hz	0.01 Hz	45 Hz	65 Hz
3 Ph Active Power	Three-Phase Watts*	W	-6000 W to 6000 W	1 W	0 W	300 W
3 Ph Reactive Power	Three-Phase Vars*	Var	-6000 Var to 6000 Var	1 Var	0 Var	300 Var
3 Ph Apparent Power	Three-Phase VA*	VA	0 to 6000 VA	1 VA	0 VA	300 VA
3 Ph Power Factor	3Ph Power Factor*	-	-1 to 1	0.01	0	1
Single-Phase Active Power	A Phase Watts* B Phase Watts* C Phase Watts*	W	-2000 W to 2000 W	1 W	0 W	100 W
Single-Phase Reactive Power	A Phase Vars* B Phase Vars* C Phase Vars*	Var	-2000 Var to 2000 Var	1 Var	0 Var	100 Var
Single-Phase Apparent Power	A Phase VA* B Phase VA* C Phase VA*	VA	0 to 2000 VA	1 VA	0 VA	100 VA
Single-Phase Power Factor	APh Power Factor* BPh Power Factor* CPh Power Factor*		-1 to 1	0.01	0	1
Three-Phase Current Demands	IA Fixed Demand* IB Fixed Demand* IC Fixed Demand* IA Roll Demand* IB Roll Demand* IC Roll Demand* IA Peak Demand* IB Peak Demand* IC Peak Demand*	A	0 to 16A	0.01A	0A	1.2A
3Ph Active Power Demands	3Ph W Fix Demand* 3Ph W Roll Dem* 3Ph W Peak Dem*	W	-6000 W to 6000 W	1 W	0 W	300 W
3Ph Reactive Power Demands	3Ph Vars Fix Dem* 3Ph Var Roll Dem* 3Ph Var Peak Dem*	Var	-6000 Var to 6000 Var	1 Var	0 Var	300 Var
Rotor Thermal State	NPS Thermal	%	0 to 200	0.01	0	120
Stator Thermal State	Thermal Overload	%	0 to 200	0.01	0	120
RTD Temperatures	RTD 1* RTD 2* RTD 3* RTD 4* RTD 5* RTD 6* RTD 7* RTD 8* RTD 9* RTD 10*	°C	-40°C to 300°C	0.1°C	0°C	200°C
Current Loop Inputs	CL Input 1 CL Input 2 CL Input 3 CL input 4	-	-9999 to 9999	0.1	0	9999
Flux, V/Hz	Volts/Hz	V/Hz	0-20	0.01	0	4
df/dt	df/dt	Hz/s	-10 to 10 Hz/s	0.01 Hz/s	-1 Hz/s	1 Hz/s

Current loop output parameter	Abbreviation	Units	Range	Step	Default min.	Default max.
Check Synch Voltages	C/S Voltage Mag C/S Bus Gen-Mag	V	0 to 200 V	0.1 V	0 V	80 V
Slip Frequency	Slip frequency	Hz	0 to 70 Hz	0.01 Hz	-0.5 Hz	0.5 Hz

Note 1 *For measurements marked with an asterisk, the internal refresh rate is nominally 1 s, others are 0.5 power system cycle or less.*

Note 2 *The polarity of Watts, Vars and power factor is affected by the Measurements Mode setting.*

Note 3 *These settings are for nominal 1A and 100/120 V versions only. For other nominal versions they need to be multiplied accordingly.*

Note 4 *For the P343/P344/P345, the IA/IB/IC Current magnitudes are IA-1 Magnitude, IB-1 Magnitude, IC-1 Magnitude.*

Table 20 - Current loop output parameters

1.34 Rotor Earth Fault Protection (64R)

Rotor earth fault protection is used to detect earth faults in the excitation circuit of synchronous machines. An earth fault in the rotor winding does not cause immediate damage; however, if a second earth fault occurs it constitutes a winding short-circuit of the excitation circuit. The resulting magnetic unbalances can cause extreme mechanical forces which may cause damage to the machine.

The rotor earth resistance is measured using an external low frequency square wave injection, coupling and measurement unit, P391, connected to the rotor circuit. The measurement of the rotor resistance is passed to the P342/P343/P344/P345 via a current loop output (0-20 mA) on the P391 connected to one of the 4 current loop inputs (0-20 mA) on the P342/P343/P344/P345. The rotor earth fault protection is only available if the relay includes the CLIO hardware option. Two under resistance stages of definite time protection are available for alarm and trip.

1.34.1 Basic Principle

1.34.1.1 Low Frequency Injection Technique

The rotor earth fault protection injects a DC voltage into the rotor circuit; the polarity of the voltage is reversed at low frequencies and the frequency is selectable by the user through a link selection, 0.25 Hz, 0.5 Hz, 1 Hz in the injection, coupling and measurement unit, P391. The voltage source is symmetrically coupled to the excitation circuit via high resistance resistors. It is also connected to the earthing brush of the rotor via a low resistance measuring shunt. The connection arrangement is a shown here:

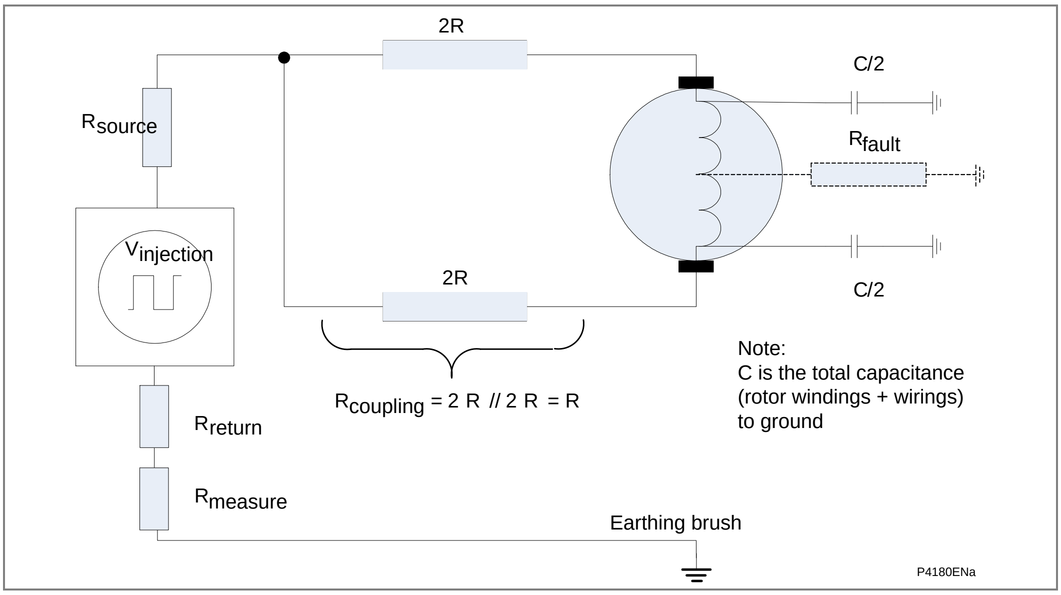


Figure 78 - Rotor earth fault protection low frequency injection arrangement

Every time the DC voltage is reversed in polarity, a charging current is applied due to the capacitance of the rotor windings to earth. Under no fault conditions, the charging current should be discharged to zero. If the measurements are made when the current reaches steady state, zero current should be measured indicating that the fault resistance is infinite.

When a rotor earth fault occurs, the steady state current will no longer be zero, the magnitude of which can then be used to calculate the fault resistance. This arrangement is complicated by the fact that, depending on the position of the fault on the excitation winding, the excitation voltage will generate an offset, Ioffset, to the fault current produced, as shown in the *Waveforms for calculating the fault current* diagram. Therefore, the measuring unit measures the steady state current for positive and negative reversal of the injection voltage; calculates the difference between the two and then takes the average. The resultant calculation is equal to the loop current through the equivalent circuit as shown in the diagram. This eliminates the effect of the capacitance from the excitation windings. It can also achieve a wider fault resistance measuring range compared to the more conventional 50/60 Hz AC injection technique.

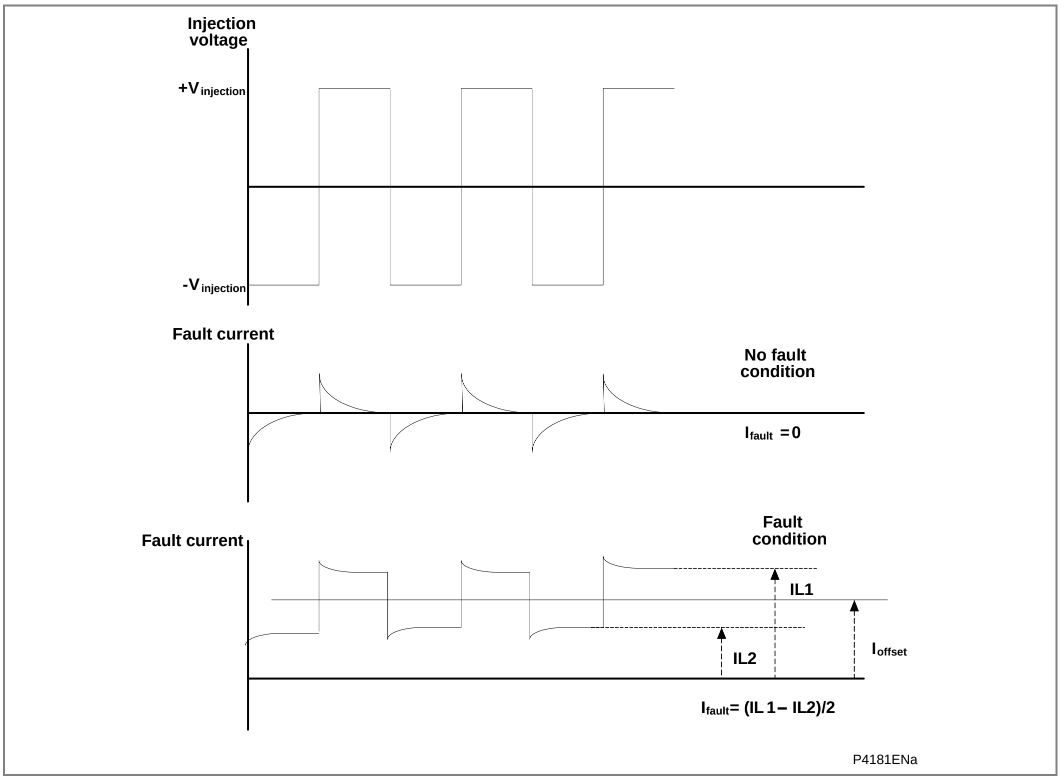


Figure 79 - Waveforms for calculating the fault current

Referring to the equivalent circuit in the following diagram, the resistor $R_{measure}$ is used as a shunt for the measurement of the steady-state loop current. By measuring the voltage across the shunt, the loop current can be established, which in turn can be used to calculate the fault resistance.

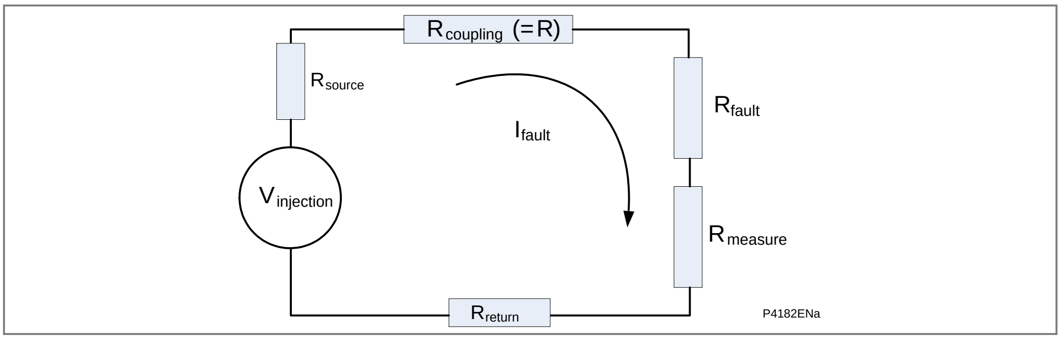


Figure 80 - Rotor earth fault equivalent circuit diagram

The injection, coupling and the measurement circuitry is implemented as a separate unit, P391, as it is desirable to mount this unit as close as possible to the excitation circuit to minimize any noise pick-up. The communication to the relay is via a 0-20 mA current loop output on the P391. The voltage drop $V_{measure}$ is passed over as a measuring quantity.

$$V_{measure} = I_{fault} * R_{measure}$$

The relay calculates the fault resistance, R_{fault}, based on the known configuration of the injection voltage, the coupling resistors, the measuring resistor, plus other resistance values in the measuring circuit (source resistance R_{source} and return path resistance R_{return}).

$$R_{fault} = \frac{V_{injection}}{V_{measure}/R_{measure}} - R_{source} - R_{coupling} - R_{measure} - R_{return}$$

$V_{measure}$ (or Ifault) and R_{fault} have an inverse relationship, as shown in the example in following diagram. This is handled intrinsically by the relay calculation.

$V_{injection} := 59.6v \quad R_{source} := 1K\Omega \quad R_{injection} := 30k\Omega \quad R_{return} := 7.5k\Omega \quad R_{measure} := 500\Omega$

$R_{total} := R_{source} + R_{injection} + R_{fault} + R_{return} + R_{\ measure}$

$I_{fault} := \dfrac{V_{injection}}{R_{total}} \qquad V_{measure} := I_{fault} \ \text{-} R_{measure}$

$R_{fault} =$ (kΩ)

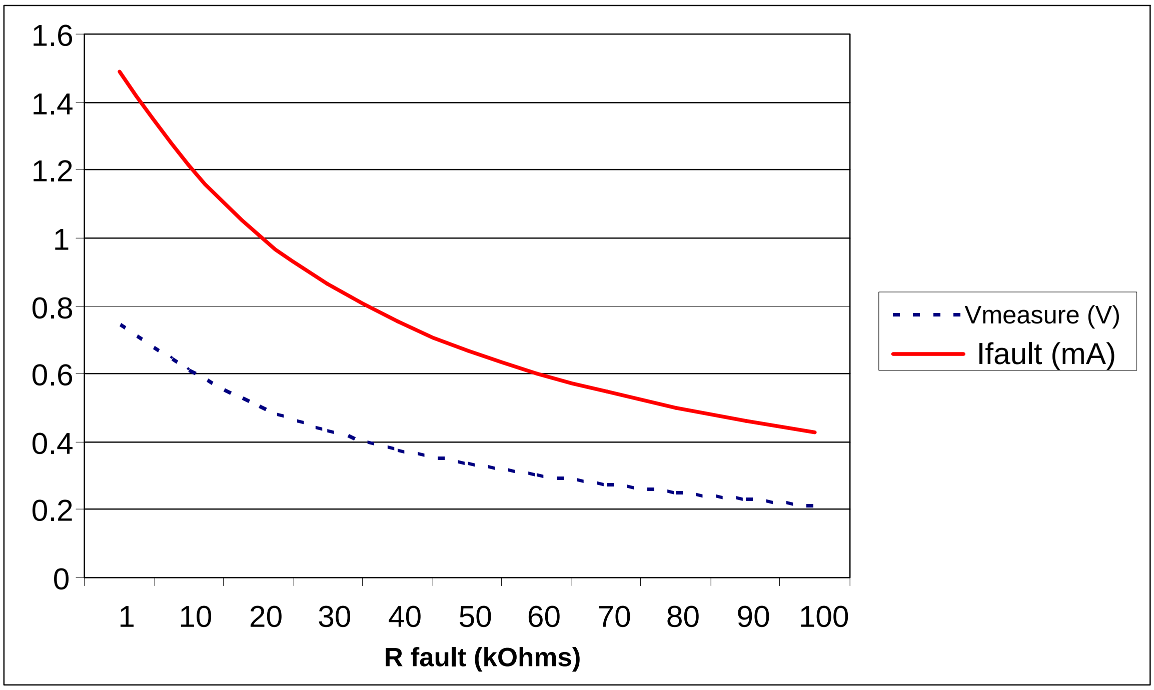
0	1
1	10
2	20
3	30
4	40
5	50
6	60
7	70
8	80
9	90
10	100

$I_{fault} =$ (mA)

0	1.49
1	1.216
2	1.01
3	0.864
4	0.754
5	0.67
6	0.602
7	0.547
8	0.501
9	0.462
10	0.429

$V_{measure} =$ (v)

0	1.49
1	1.216
2	1.01
3	0.864
4	0.754
5	0.67
6	0.602
7	0.547
8	0.501
9	0.462
10	0.429



P4184ENa

Figure 81 - Relationship between fault current and fault resistance

The P391 0-20 mA current loop output has been designed to drive 20 mA through a maximum load of 500 Ohms. The relay current loop input resistance is 360 Ohms. For redundant rotor earth fault applications, a repeater can be used to connect the P391 0-20 mA output to 2 x relays, see the Applications Notes chapter for more information on this application.

For 1/0.6 mm lightweight cable (CSA 0.28 mm^2) the cable resistance is 65 Ohms/km so for this cable the maximum cable distance between the P391 and P34x relays can be approx. 1km, (maximum cable length (km) = 140/loop resistance 2Rl = 140/2x65 = 1.07km). It is recommended that a screened cable earthed at one end is used to reduce interference.

1.34.2 Noise Filtering

As the injection, coupling and measuring unit performs the I_{fault} (or $V_{measure}$) measurement, it is essential that the filtering capability of the unit is sufficient to reject any noise which could interfere with the measuring process.

For the relays, it is necessary to ensure that the effect of noise coupled to the current loop input link is minimized to avoid acquisition of erroneous values.

The rate of data update between the injection, coupling and measuring unit and the relay is governed by the injection frequency. Even for the fastest injection frequency of 1 Hz the current loop input is updated only once a second. The sampling interval of the CLIO input is 50 ms (20 Hz sampling rate) therefore there are at least 20 samples for each calculation.

However, the noise immunity is good with a screened cable earthed at one end. There is also a low pass filter with a -3 db cut-off point of 23 Hz installed at the CLIO input.

A count strategy is implemented so as to remove any spikes or sporadic erroneous data acquisition. This supplements the existing security measures consisting of the low pass filter and a properly earthed screen connection. If there is any risk of mal-operation during the start-up and run-down of the generator, for example, then it is recommended that the inhibit signal should be utilized.

The rotor earth fault protection provides a consistency check of two consecutive acquisitions from the CLIO acquisition system before a start decision is made. This will give a delay of around 100 ms (based on the CLIO sampling interval of 50 ms) plus extra time caused by protection scheduling.

1.34.3 Fault Resistance Filtering

To overcome a sudden change in the fault resistance causing under/overshoot in the input data measurements input filtering is implemented.

When the filter detects an input resistance step change of greater than 5%, the previous CL input and fault resistance values are held (and continue to be produced at the filter's output), until the input data has settled. Two concurrent recovery strategies are implemented:

- Data consistency checking
- Time delay

1.34.3.1 Data Consistency Checking

To establish if the input data has settled, consistency checking is performed to determine when a certain number of consecutive data samples are consistent, within the required tolerance. This is achieved by recording data samples in a rolling buffer (cyclic buffer), starting when the step change occurs. The number of samples, and thus buffer size, depends on the injection frequency, obtained from the settings (see the *Filter parameters for each injection frequency* table). The check takes place over a period of 3 / 4f. Once enough samples have been captured, the oldest sample is compared with the others. If any differ by more than the required tolerance the oldest sample is rejected and the rolling buffer moves forward when the next sample is obtained. If all the samples are consistent the filter outputs are no longer held and are updated with the 'current' values (effectively the newest value in the sample buffer). The minimum time to achieve consistent data is the time to fill the rolling buffer, for example: at 0.25 Hz the buffer size is 60 samples which takes 3.0 seconds to fill (60 x 50 ms CLIO update time).

1.34.3.2 Time Delay

A time delay of 2/f is waited to allow the inputs to settle (where f is the injection frequency, obtained from the settings). If the 2/f delay expires (before the consistency check passes), a ‘snapshot’ of the ‘current’ input values is output from the filter, irrespective of the consistency check. When this occurs, the new data values are then held and the timer is immediately restarted. Therefore, the consistency check must be passed before consecutive ‘current’ samples are used, otherwise the timer will expire again and another ‘snapshot’ of data will be used.

The data is only considered ‘settled’ when the consistency check is passed. These two strategies complement each other, as the consistency check allows quicker recovery in most circumstances (see the *Stability recovery via consistent data @ 0.25 Hz* diagram), while the time delay strategy provides a timeout for the consistency checking, therefore preventing lock up.

When the ‘forced’ flag input is set, both filter strategies are immediately overridden, as any step change to a forced value is a legitimate change, due to an internal decision, rather than an unwanted overshoot.

The filter parameters for each injection frequency are shown in this table:

Frequency (Hz)	Hold Timeout 2/f (seconds)	Sample buffer size	Time to collect sample buffer size (seconds)
0.25	8	60	3.0
0.5	4	30	1.5
1.0	2	15	0.75

Table 21 - Filter parameters for each injection frequency

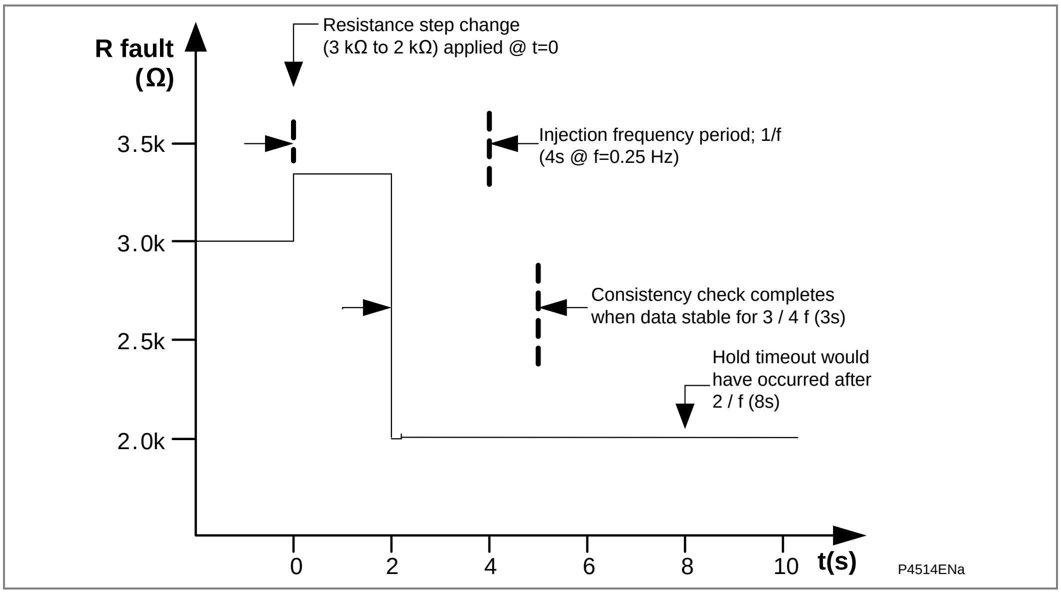


Figure 82 - Stability recovery via consistent data @ 0.25 Hz

1.34.4 Description

The rotor earth fault protection uses direct voltage injection, with low frequency polarity reversal as stated above. The low frequency range, 0.25 Hz, 0.5 Hz and 1 Hz, is selected via a link selection inside the injection, coupling and measuring unit P391. This protection is only available if the relay includes the CLIO hardware option.

The method to calculate the fault resistance is based on the equivalent circuit as shown in the *Rotor earth fault protection block* diagram. The injection, coupling and measuring unit measures the voltage across a measuring resistor, as shown in the *Rotor earth fault protection block* diagram. This measured voltage, $V_{measure}$, which is proportional to the fault current, I_{fault}, is passed to the relay through one of the 0-20 mA current loop inputs, selectable by the user.

The coupling resistance, injection voltage, and the measuring resistance values are dependent on the injection, coupling and measurement unit hardware design and are fixed inside the relay. These values are required for the fault resistance calculation. A setting **R Compensation** is included for calibration adjustment during commissioning.

The relay calculates the fault resistance R_{fault} using the following formula:

$$R_{fault} = \frac{V_{injection}}{V_{measure}/R_{measure}} - R_{source} - R_{coupling} - R_{measure} - R_{return} + R_{Compensation}$$

The rotor earth fault protection includes 2 stages of under resistance protection. The under resistance protection is designed as a two stage protection system, one alarm stage (64R R<1 Alarm) and one trip stage (64R R<2 Trip), with each stage having a definite time delay setting. All the protection stages have separate DDB signals to indicate the start and alarm or trip of each stage and DDB signals to inhibit operation of each stage.

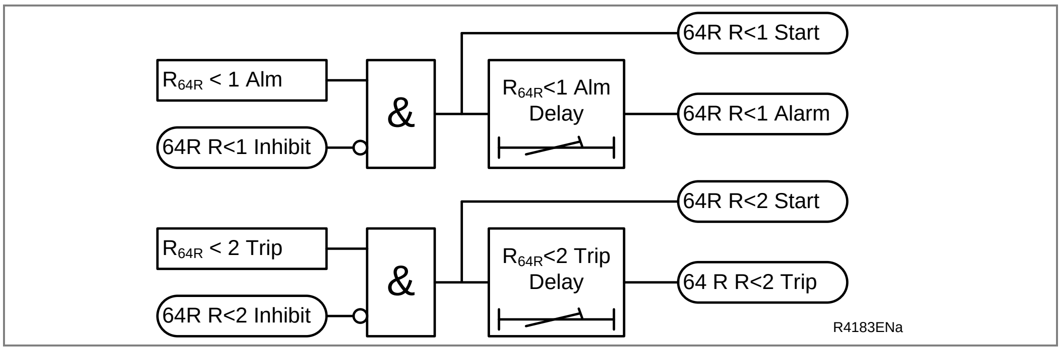


Figure 83 - Rotor earth fault protection block diagram

The 64R rotor earth fault 64R R<1/R<2 stages can be independently inhibited by energizing the relevant DDB signal via the PSL (64R R<1/R<2 Inhibit: DDB 556/557). DDB signals are also available to indicate the start, alarm and trip of the protection stages, (64R Start R<1 Alm/64R R<2 Start: DDB 1022/1023, 64R R<1 Alarm: DDB 394, 64R R<2 Trip: DDB 780). A DDB signal is also available to indicate the 64R current loop input failure (64R CL I/P Fail; DDB 395).

The rotor earth fault protection starts are mapped internally to the ANY START DDB signal – DDB 992.

The fault resistance calculation and the protection function is executed twice every power system cycle. Although rotor earth fault is essentially a "slow" protection due to the infrequent update of the input data acquisition, executing the protection twice per cycle provides some improvement to the response time, particularly when the power system frequency is low. A count strategy of 2 is implemented, the start output is asserted only if the fault resistance exceed the threshold for 2 consecutive calculations. A drop-off/pick-up ratio of 105% or 110% (depending on setting) is applied to the settings once the start has operated.

To avoid any overshoot problem when there is a sudden change in fault resistance, an 'input filter' is implemented which holds any start/trip and count decisions and measurement values. The 'hold' takes place if the resistance value change is greater than 5%. It lasts up to a duration of 2 periods of the injection frequency.

Note	*The measurement values in the disturbance records are not filtered.)*

An independent CLIO input monitoring element is included to monitor invalid input data from the selected current loop input. Consistent invalid inputs inhibit the protection and cause an alarm (64R CL I/P Fail :DDB 780) to be raised after 1 s.

1.34.5 Measurements

The following are available in the Measurements 3 column:

MEASUREMENTS 3
64R CL Input
64R R Fault

Table 22 - Measurements 3

The **64R CL Input** is the 0-20 mA current loop input measured by the relay. This provides monitoring of the current loop signal between the P391 and the P34x. The relay provides a forced value (**CL Input invalid** for the front panel, 0 mA for the remote communications) if the current loop input data is found to be invalid.

The **64R Fault** measurement is the fault resistance calculated by the relay. The relay provides capped values if the fault resistance measurement is beyond the supported range (e.g., 50 ohms to 1M ohms).

The Disturbance recorder analogue input selection includes the **64R CL Input Raw** and **64R R Fault Raw** (unfiltered values) and **64R R Fault** (filtered value) channels. They are sampled at the recorder's sampling frequency, 24 samples/power system cycle.

Forced R_{fault} value	Forced or capped value	Value meaning
9.999 MΩ	Capped	Infinity value (divide by zero prevented).
9.998 MΩ	Forced	CLIO input data invalid
9.997 MΩ	Forced	Rotor EF protection disabled.
9.996 MΩ	Capped	R fault above upper limit (1 MΩ)
0 Ω	Capped	R fault below lower limit (50 Ω).

Table 23 - Forced values for 64R

2 OPERATION OF NON PROTECTION FUNCTIONS

2.1 Check Synchronism (25)

2.1.1 Overview

In most situations it is possible for both the **Generator** and **Bus** sides of a circuit breaker to be live when the circuit breaker is open, for example where the Bus has a power source. 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 manual circuit breaker closing of any CB and auto-reclosure applications specific to feeder CBs. If a circuit breaker is closed when the generator 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).

For generator applications before closing the CB the frequency and voltage from the machine is varied automatically or manually until the generator voltage is in synchronism with the power system voltage. A check synchronizing relay is used to check the generator voltage is in synchronism with the system voltage in terms of voltage magnitude, voltage difference, phase angle and slip frequency before the generator CB is allowed to close.

2.1.2 VT Selection

The relay has a three-phase **Main VT** input for the generator protection functions in the relay and a single-phase **Check Sync VT** input. In the primary system arrangement, you have a busbar on one side and a generator on the other side; with the circuit breaker located between them. Therefore the **Main VT** can be located either between the circuit breaker and the busbar OR between the circuit breaker and the generator. The **Check Sync VT** is then on the other side of the circuit breaker (i.e. the side which does not have the **Main VT**). Hence, the relay has to be programmed with the location of the **C/S VT**. This is done via the **C/S VT Location** setting in the **SYSTEM CONFIG** menu. This is required for the voltage monitors to correctly define the Live Gen/Dead Gen and Live Bus/Dead Bus DDBs.

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.

The P342/P343 uses the neutral voltage input, VNeutral, for the Check Synch VT and so the user can not use check synch and measured neutral voltage (59N) protection (VN>3, VN>4) at the same time. The derived neutral voltage protection (VN>1, VN>2) from the 3 phase voltage input can still be used with the check synchronizing function.

The P344 uses the neutral voltage input, VN2, for the Check Synch VT and so the user can not use check synch and measured neutral voltage (59N) protection from VN2 (VN>5, VN>6) at the same time. The derived neutral voltage protection (VN>1, VN>2) from the 3 phase voltage input and the measured neutral voltage protection (VN>3, VN>4) from the VN1 voltage input can still be used with the check synchronizing function.

The P345 uses a dedicated V Check Sync voltage input for the Check Synch VT and so there are no restrictions in using the check synchronizing function and other protection functions in the relay.

2.1.3 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.

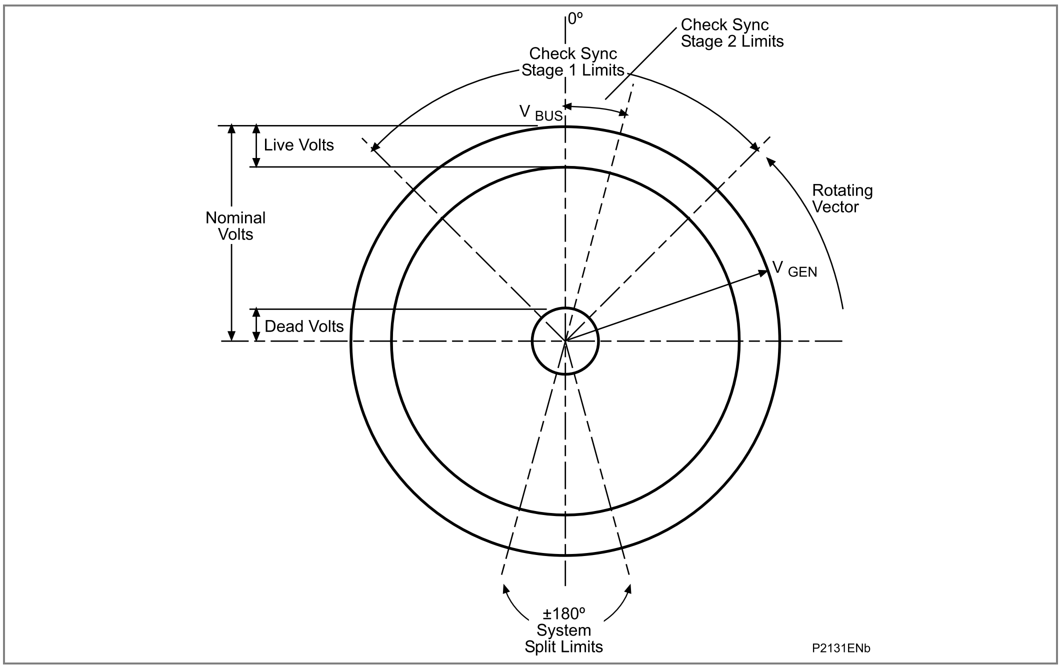


Figure 84 - Synchro check and synchro split functionality

The overall "**Check Sync.**" and "**System Split**" functionality is shown in the previous diagram.

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.

2.1.3.1 Voltage Monitors

The System Checks function includes voltage monitors to indicate if the generator and system busbar voltages are Live or Dead.

The voltage monitor DDBs, if required, are combined in the PSL to provide the manual CB close check synchronizing logic, eg Dead Line/Live Gen. The DDBs are connected to the Man Check Synch DDB (1362) which provides an input to the CB control logic to indicate a manual check synchronizing condition is satisfied.

- When Vgen magnitude is > Live Voltage, the generator is taken as Live (DDB 1328, Live Gen)
- When Vgen magnitude is < Dead Voltage, the generator is taken as Dead (DDB 1329, Dead Gen)
- When Vbus magnitude is > Live Voltage, the busbar is taken as Live (DDB 1330, Live Bus)
- When Vbus magnitude is < Dead Voltage, the busbar is taken as Dead (DDB 1331, Dead Bus)

2.1.3.2 Synchronism Check

The System Checks function includes 2 check synchronization elements, Check Sync 1 and Check Sync 2. The check synch 1 OK (1332) and Check Synch 2 OK (1333) DDBs, if required, are used in the PSL to provide the manual CB close check synchronizing logic. The DDBs are connected to the Man Check Synch DDB (1362) which provides an input to the CB control logic to indicate a manual check synchronizing condition is satisfied.

Each check synch element checks that the generator frequency, voltage magnitude, and phase angle match the system frequency, voltage magnitude, and phase angle before allowing the generator breaker to be closed. Each element includes settings for the phase angle difference and slip frequency between the generator and system busbar voltages.

The relay also includes independent under/over voltage monitors for the generator and system side of the CB as well as a differential voltage monitor applicable to both the Check Sync 1 and 2 elements. The user can select a number of under/over/differential voltage check synchronizing blocking options using the setting **CS Voltage Block** – **None, V<, V>, Vdiff>, V< and V>, V< and Vdiff>, V> and Vdiff>, V< V> Vdiff>.**

The slip frequency used by Check Synch 1/2 can be calculated from the **CS1/2 Phase Angle** and **CS1/2 Slip Timer** settings as described below or can be measured directly from the frequency measurements, slip frequency = |Fgen-Fbus|. The user can select a number of slip frequency options using the settings **CS1 Slip Control** – **None, Timer Only, Frequency Only, Frequency + Timer , Frequency + CB** and **CS2 Slip Control** – **None, Timer, Frequency**.

If Slip Control by **Timer** or **Frequency + Timer**/**Both** is selected, the combination of **CS Phase Angle** and **CS Slip Timer** settings determines an effective maximum slip frequency, calculated as:

$$\frac{2 \text{ x } A}{T \text{ x } 360} \quad \text{Hz. for Check Sync. 1, or}$$

$$\frac{A}{T \text{ x } 360} \quad \text{Hz. for Check Sync. 2}$$

A = Phase Angle setting (°)

T = Slip Timer setting (seconds)

The **Frequency + CB** (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 therefore minimizing 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 four times per power system cycle, based on frequency tracking over the frequency range of 5 Hz to 70 Hz.

Check Sync 1 and Check Sync 2 are two synchronism check logic modules with similar functionality, but independent settings (see the *Synchro check and synchro split functionality* diagram).

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:

Gen volts and bus volts are both live (Gen Live and Bus Live signals both set)
AND

measured phase angle is < **CS1/2 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 **CS1/2 Slip Control** is set to **Frequency Only** or **Frequency** or **Frequency + Timer**, the measured slip frequency is < **CS1/2 Slip Freq** Setting
AND

if **CS Voltage Block** is set to **V>** or **V< and V>** or **V> and VDiff>** or **V< V> Vdiff>,** both generator voltage and busbar voltage magnitudes are < **Gen Over Voltage** and **Bus Over Voltage** setting respectively
AND

if **CS Voltage Block** is set to **V<**, or **V< and V>** or **V< and Vdiff>** or **V< V> Vdiff>,** generator voltage and busbar voltage magnitudes are > **Gen Under Voltage** and **Bus Under Voltage** setting respectively
AND

if **CS Voltage Block** is set to **Vdiff>** or **V< and Vdiff** or **V> and VDiff>** or **V< V> Vdiff>**, the voltage magnitude difference between generator voltage and busbar voltage is < **CS Diff Voltage** setting
AND

if **CS 1/2 Slip Control** is set to **Timer** or **Frequency + Timer** (CS1) / **Freq + Timer** (CS2), the above conditions have been true for a time > or = **CS 1/2 Slip Timer** setting

2.1.3.3 System Split

For the System Split module to function:

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:

Gen volts and bus volts are both live (Line Gen and Bus Live signals both set)
AND

measured phase angle is > **SS Phase Angle** setting
AND

if **SS Volt Blocking** is set to **Enabled**, both gen 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.

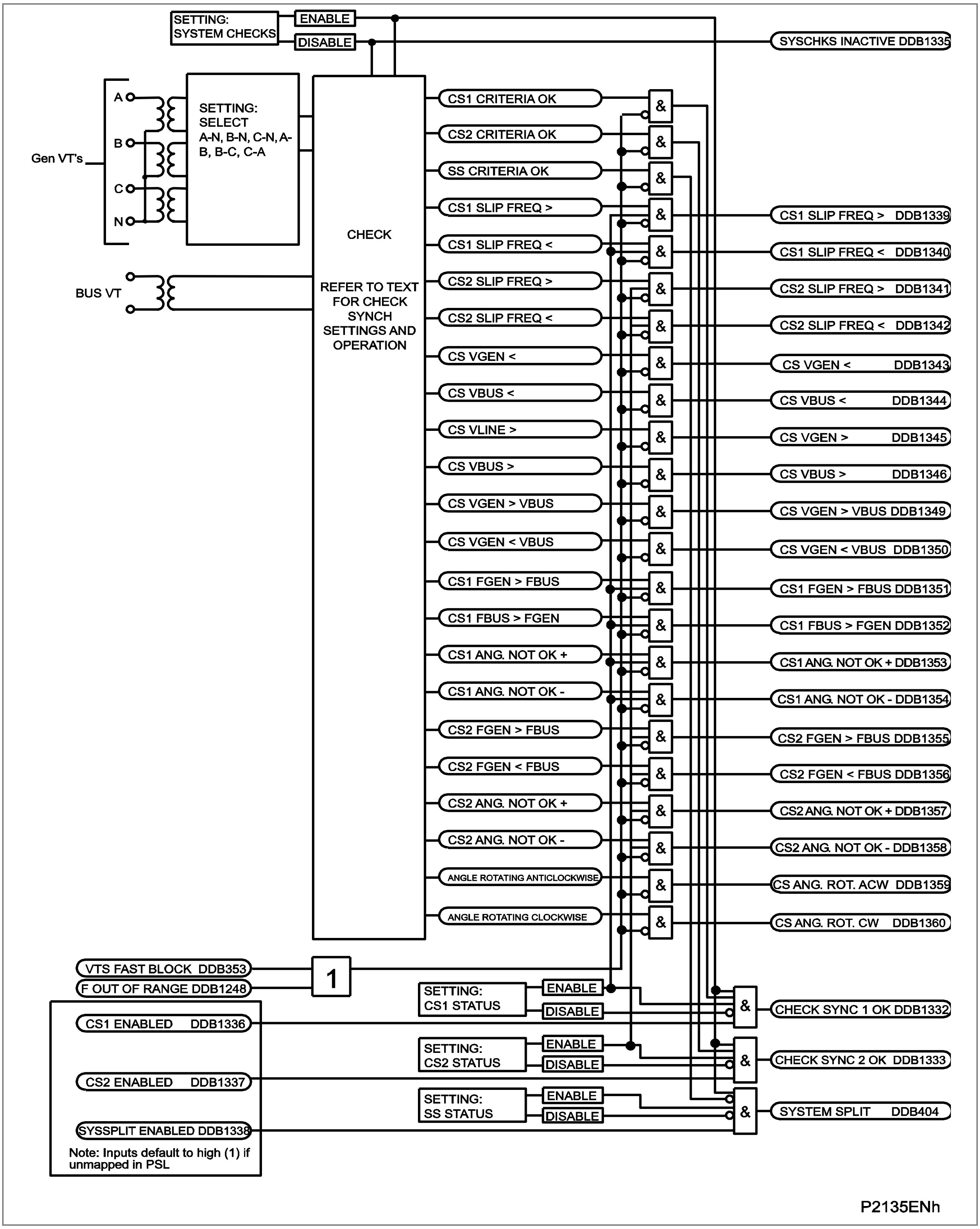


Figure 85 - System checks functional logic diagram

2.1.3.4 Voltage and Phase Angle Correction

This **C/S V Ratio Corr** setting in the **SYSTEM CONFIG** menu is used by the **System Check** function to provide magnitude correction to the check synch VT to correct for small differences between the main VT and check synch VT. Magnitude differences may be introduced by unmatched or slightly erroneous voltage transformer ratios, normally the setting is close to 1.0.

The **Main VT Vect Grp** setting in the **SYSTEM CONFIG** menu is used by the **System Check** function to provide vector correction between the main VT and check synch VT caused by the vector group phase shift (eg 30 degree phase shift for a Dy11 or Dy1 transformer vector group) across the generator-transformer.

There are some applications where the main VT is on the generator side of a transformer and the check sync VT is in the transformer LV side or vice-versa where vector group correction may be required.

2.2 Voltage Transformer Supervision (VTS)

The Voltage Transformer Supervision (VTS) feature is used to detect failure of the ac voltage inputs to the relay. 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:

- Loss of one or two phase voltages
- Loss of all three phase voltages under load conditions
- Absence of three phase voltages on line energization

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

2.2.1 Loss of all Three-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), 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 0.1 In.

2.2.2 Absence of Three-Phase Voltages on Line Energisation

If a VT were inadvertently left isolated prior to line energization, incorrect operation of voltage dependent elements could result. The previous VTS element detected 3-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 3-phase VT failure is therefore required on-line energization.

The absence of voltage measurements on all three phases with line energized can result of two conditions:

- A 3-phase VT failure
- A close up 3-phase fault

The first condition would require blocking of the voltage dependent function and the second would require tripping.

To differentiate between these two conditions, an overcurrent level detector (“VTS Imax> Inh”) 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 3-phase VT failure is present, the overcurrent detector will not operate and a VTS block will be applied. Closing onto a 3-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, where no voltage will be present and the **VTS I> Inhibit** overcurrent element will not be picked up.

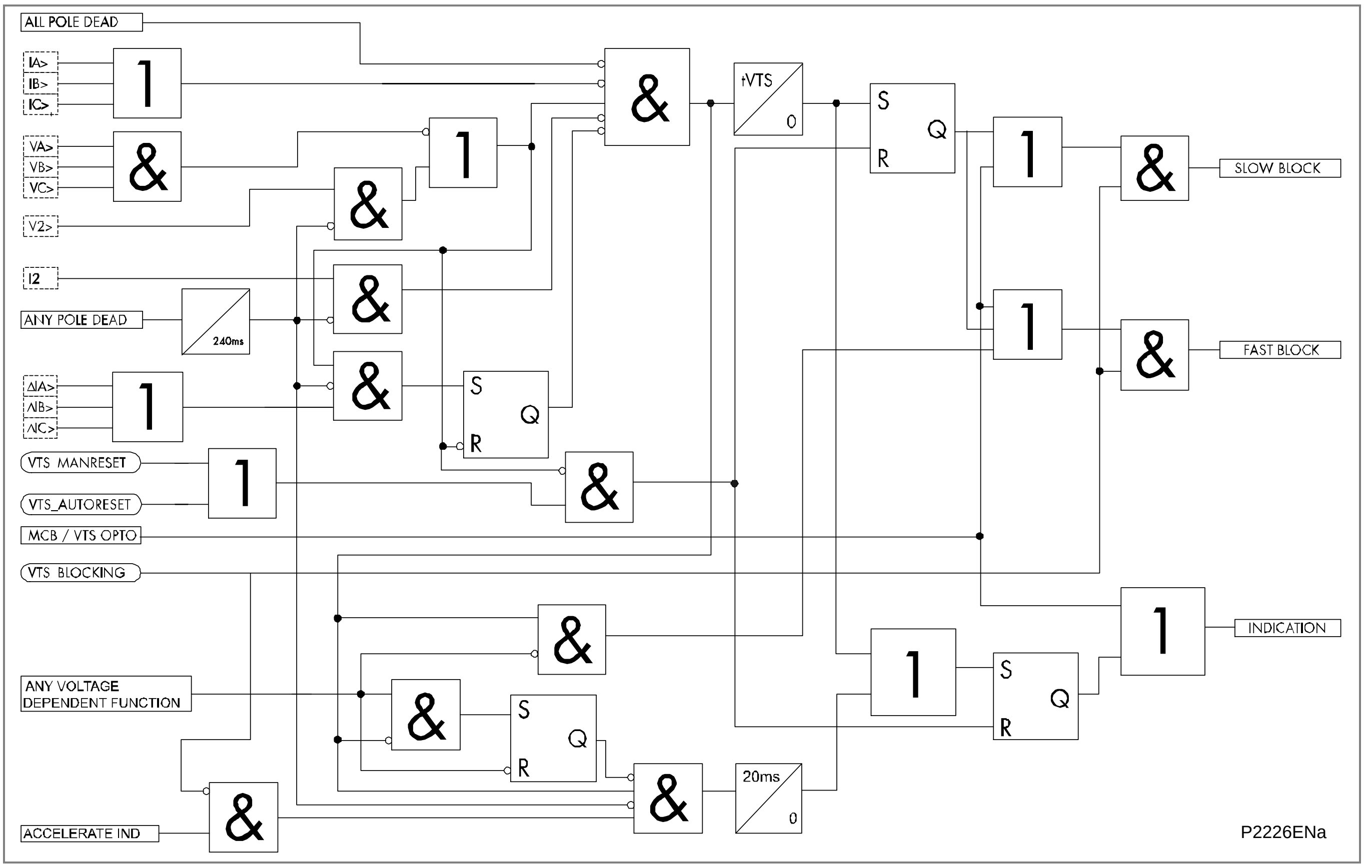


Figure 86 - VTS logic

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 20 ms and their settings should be greater than load current. This setting is specified as the VTS current threshold. These level detectors pick-up at 100% of setting and drop-off at 95% of setting.
- I2>, this level detector operates on negative sequence current and has a user setting. This level detector picks-up at 100% of setting and drops-off at 95% of setting.
- ∆IA>, ∆IB>, ∆IC>, these level detectors operate on superimposed phase currents and have a fixed setting of 10% of nominal. These level detectors are subject to a count strategy such that 0.5 cycle of operate decisions must have occurred before operation.
- VA>, VB>, VC>, these level detectors operate on phase voltages and have a fixed setting, Pick-up level = 30 V (Vn = 100/120 V), 120 V (Vn = 380/480 V), Drop Off level = 10 V (Vn = 100/120 V), 40 V (Vn = 380/480 V).
- V2>, this level detector operates on negative sequence voltage, it has a fixed setting of 10 V/40 V depending on VT rating (100/120 or 380/480) with pick-up at 100% of setting and drop-off at 95% of setting.

2.2.2.1 Inputs

Signal name	Description
IA>, IB>, IC>	Phase current levels (Fourier magnitudes)
I2>	I2 level (Fourier magnitude).
∆IA, ∆IB, ∆IC	Phase current samples (current and one cycle previous)
VA>, VB>, VC>	Phase voltage signals (Fourier magnitudes)
V2>	Negative sequence voltage (Fourier magnitude)
ALL POLE DEAD	Breaker is open for all phases (driven from auxiliary contact or pole dead logic).
VTS_MANRESET	A VTS reset performed via front panel or remotely.
VTS_AUTORESET	A setting to allow the VTS to automatically reset after this delay.
MCB/VTS OPTO	To remotely initiate the VTS blocking via an opto
Any Voltage Dependent Function	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.
Accelerate Ind	Signal from a fast tripping voltage dependent function used to accelerate indications when the indicate only option is selected
Any Pole Dead	Breaker is open on one or more than one phases (driven from auxiliary contact or pole dead logic)
tVTS	The VTS timer setting for latched operation

Table 24 - VTS inputs

2.2.2.2 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 25 - VTS outputs

2.2.3 Operation

The relay may respond as follows to an operation of any VTS element:

- VTS set to provide alarm indication only (DDB 356 VT Fail Alarm);
- Optional blocking of voltage dependent protection elements (DDB 1248 VTS Fast Block, DDB 1249 VTS Slow Block);
- Optional conversion of directional SEF, directional overcurrent and directional NPS 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.

Time delayed protection elements (Directional NPS Overcurrent, Directional SEF, Power, Sensitive Power, Field Failure) are blocked after the VTS Time Delay on operation of the VTS Slow Block. Fast operating protection elements (Directional overcurrent, Neutral Voltage Displacement, System Backup, Undervoltage, Dead Machine, Pole Slipping, NPS Overpower) are blocked on operation of the VTS Fast Block.

Note	*The directional SEF and neutral voltage displacement protection are only blocked by VTS if the neutral voltage input is set to Derived and not Measured.*

Other protections can be selectively blocked by customizing the PSL, integrating DDB 1248 VTS Fast Block and DDB 1249 VTS Slow Block with the protection function logic.

The VTS I> Inhibit or VTS I2> Inhibit elements are used to override a VTS block in event of a fault occurring on the system which could trigger the VTS logic. Once the VTS block has been established, however, then it would be undesirable for subsequent system faults to override the block. The VTS block will therefore 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) provided the VTS condition has been removed and secondly, when in ‘Auto’ mode, by the restoration of the 3-phase voltages above the phase level detector settings mentioned previously.

A VTS indication will be given after the VTS Time Delay has expired. In the case where the VTS is set to indicate only the relay may potentially maloperate, depending on which protection elements are enabled. In this case the VTS indication will be given prior to the VTS time delay expiring if a trip signal is given.

Where a Miniature Circuit Breaker (MCB) is used to protect the voltage transformer ac output circuits, it is common to use MCB auxiliary contacts to indicate a three-phase output disconnection. It is possible for the VTS logic to operate correctly without this input. However, this facility has been provided for compatibility with various utilities current practices. Energizing an opto-isolated input assigned to MCB/VTS (DDB 874) on the relay will therefore provide the necessary block.

Where directional overcurrent elements are converted to non-directional protection on VTS operation, it must be ensured that the current pick-up setting of these elements is higher than full load current.

The blocking of the VTS logic for a number of different fault conditions is considered below, assuming Vn = 100/120 V.

1. Phase-earth fault

    The I2> element should detect phase-earth faults and block the VTS logic when the CB is closed for solidly earthed generators.

    For a high impedance earthed system the level of Io, I2 and V2 will be very small <5% for an earth fault. For a generator connected to load if there is a close-up earth fault where the voltage on 1 phase < 10 V and the delta change in current on the faulted phase is >10%In the VTS logic is blocked.

    For example if load current is 0.5 In and there is an A-N fault then the current in the faulted phase will drop to say 1%In during an earth fault and so delta IA = 0.49 In which is > 0.1 In delta threshold. So, Delta I = ON, Any Pole Dead = OFF, VA> = OFF (<10 V) for a close up fault and so the VTS is blocked.

    During starting of the machine if the CB auxiliary contacts are indicating the CB is open the VTS logic is blocked. However, if a contact is used to indicate the CB is closed during the start up of the machine then the VTS logic will be active.

    If there is an A-N fault during the start-up of the machine and the CB is closed and the voltage was >30 V (VA>/VB>/VC>) if the VA> element drops off (<10 V) due to the fault and the delta change in current is <10% In (delta IA>) there could be a potential incorrect operation of the VTS logic.

    So, if the load current during the start up period is < 0.1In then there could be a false VTS operation if the relay thinks the CB is closed. If the VTS operates it will block the derived neutral voltage protection but the measured neutral voltage protection is not blocked and will trip correctly during an earth fault.

2. Phase-phase fault

    The I2> element should detect phase-phase faults and block the VTS logic when the CB is closed.

3. Three-phase faults

    The delta current level detectors should detect the change in current for a close up three-phase fault when the CB is closed and block the VTS.

    The IA>/IB>/IC> level detectors should detect a three-phase fault when closing the CB onto a fault and block the VTS logic.

2.3 CT Supervision

The CT supervision feature operates on detection of derived residual current, in the absence of corresponding derived or measured residual voltage that would normally accompany it.

The CT supervision can be set to operate from the residual voltage measured at the VNEUTRAL input (VN1 input for P342/P343/P344/P345) or the residual voltage derived from the three-phase-neutral voltage inputs as selected by the 'CTS Vn Input' setting.

The voltage transformer connection used must be able to refer residual voltages from the primary to the secondary side. Therefore, this element should only be enabled where the three-phase VT is of five limb construction, or comprises three single-phase units, and has the primary star point earthed. A derived residual voltage or a measured residual voltage is available.

There are two stages of CT supervision CTS-1 and CTS-2. The derived neutral current is calculated vectorially from IA, IB, IC for CTS-1 and IA-2, IB-2, IC-2 for CTS-2. The neutral voltage is either measured or derived, settable by the user.

CTS-1 supervises the CT inputs to IA, IB, IC which are used by the biased differential protection and all the power, impedance and overcurrent based protection functions. CTS-2 supervises the CT inputs to IA-2, IB-2, IC-2 which are used by the biased or high impedance differential or interturn protection in the P343/P344/P345. The CTS-2 independent enabled/disabled setting is to prevent CTS-2 from giving unnecessary alarms when the Generator Differential is disabled. For interturn faults, some utilities may isolate the faulted winding section and return the generator to service, therefore producing unbalanced phase currents. Under these circumstances the CTS-2 may also need to be disabled or de-sensitized to prevent a false alarm and a false block.

Operation of the element will produce a time-delayed alarm visible on the LCD and event record (plus DDB 357: CT-1 Fail Alarm, DDB 381 CT-2 Fail Alarm), with an instantaneous block (DDB 1263: CTS-1 Block, DDB 1264 CTS-2 Block) for inhibition of protection elements. Protection elements operating from derived quantities, (Negative Phase Sequence (NPS) Overcurrent, NPS Thermal, NPS Overpower, Thermal Overload protection) are always blocked on operation of the CTS-1 supervision element; other protections can be selectively blocked by customizing the PSL, integrating DDB 1263: CTS-1 Block and DDB 1264: CTS-2 Block with the protection function logic. If blocking of the generator differential protection or interturn protection is required from the CT supervision this must be done in PSL by connecting DDB 1263: CTS-1 Block OR DDB 1264: CTS-2 Block to DDB 512: Gen Diff Block.

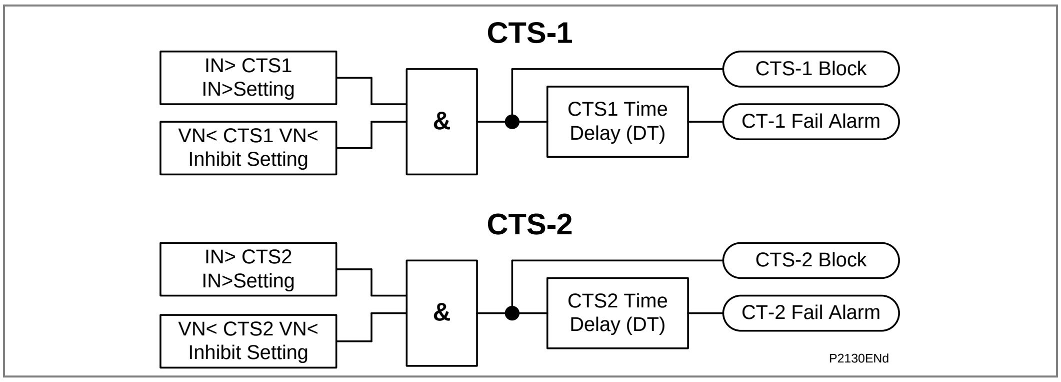


Figure 87 - CT supervision diagram

2.4 Differential Current Transformer Supervision (P343/P344/P345)

The differential current transformer supervision is based on the measurement of the ratio of I2/I1 at all ends. When this ratio is not zero, one of these two conditions may be present:

- An unbalanced fault is present on the system – both I2 and I1 are non-zero
- There is a 1 or 2 phase CT problem – both I2 and I1 are non-zero

If the I2/I1 ratio is greater than the set value, **CTS I2/I1>2**, at all ends, it is almost certainly a genuine fault condition (**CTS I2/I1>2** set above maximum unbalanced load and below the minimum unbalanced fault current). Therefore, CTS will not operate. If this ratio is detected at one end only, one of these conditions may be present:

- A CT problem
- A single end fed fault condition

I1 is used to confirm whether it is a CT problem or not. If I1 is greater than **CTS I1** at all ends, it must be a CT problem and CTS is allowed to operate. If this condition (I1 greater than CTS I1) is detected at only one end, it is assumed that either an inrush condition or a single end fed internal fault is present. Therefore, the CTS operation is blocked.

The CTS status under the **CT SUPERVISION** heading can be set either as indication or restraint. In indication mode, the CTS alarm time delay is automatically set to zero. If a CT failure is present, an alarm would be issued without delay, but the differential protection would remain unrestricted. Therefore, the risk of unwanted tripping under load current is present. In restraint mode, the differential protection is blocked for 20 ms after CT failure has been detected. Then the new setting **Is-CTS** is applied to the differential protection, as shown in the diagram below, the restraint region of the bias characteristic increases. The low impedance REF, derived earth fault (P341) and NPS overcurrent protections are internally blocked by CTS when a CT failure is detected in the CT used by each protection function.

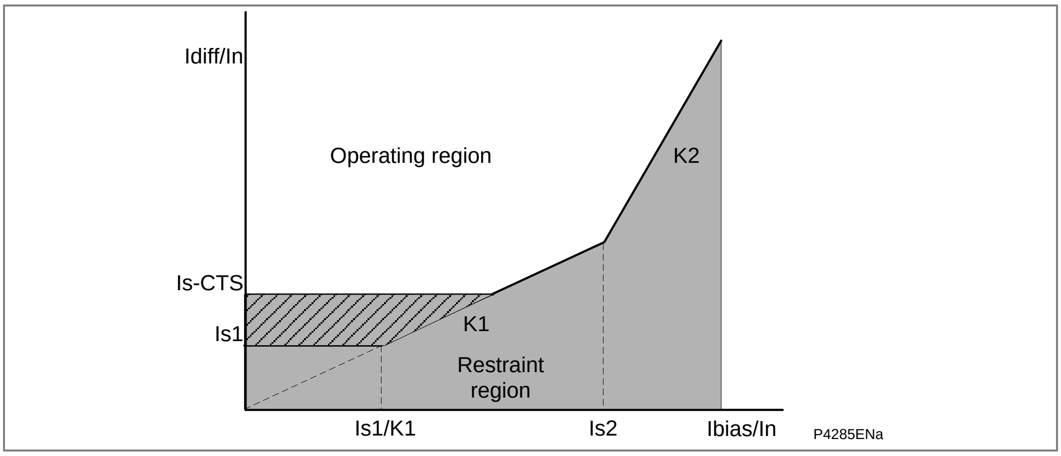


Figure 88 - CTS I1 setting applied to the differential protection

The simplified logic diagram of CTS is shown below:

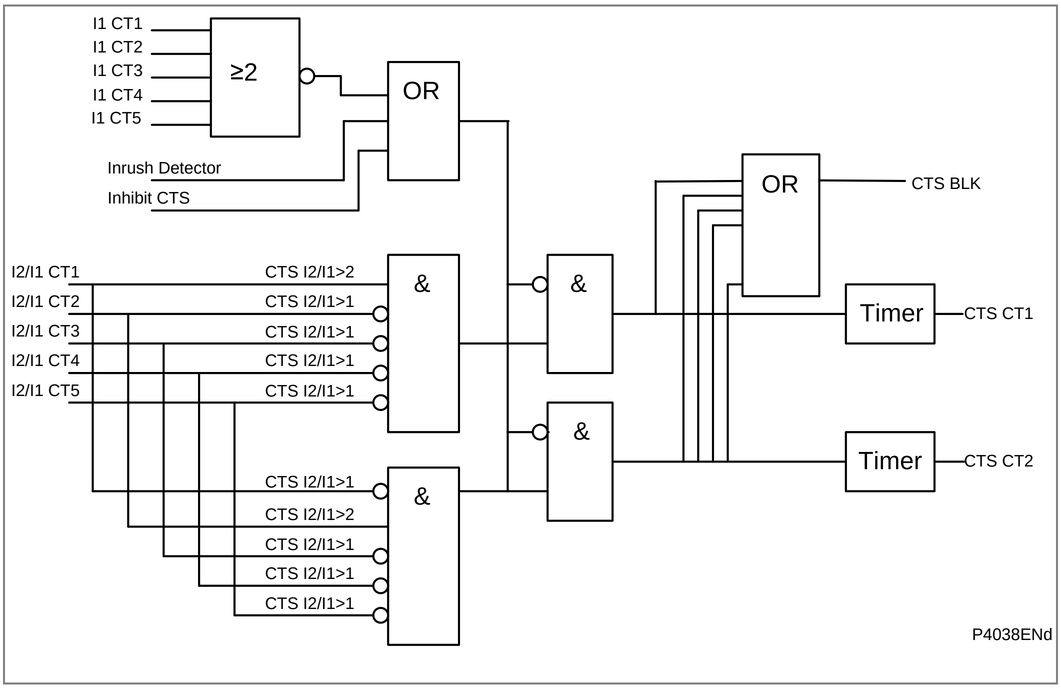


Figure 89 - Differential CTS logic diagram

The above diagram shows the CTS monitors the positive and negative sequence currents of all ends (2). A faulty CT is determined if the following conditions are present at the same time:

- The positive sequence current in at least two current inputs exceeds the set release threshold I1 (**CTS I1** setting under the **SUPERVISON** menu). This also means that CTS can only operate if minimum load current of the protected object is present.
- On exactly one end a high set ratio of negative to positive sequence current, CTS I2/I1>2, is exceeded.
- On all other ends the ratio of negative to positive sequence current is less than a low set value, CTS I2/I1> 1, or no significant current is present (positive sequence current is below the release threshold I1)

Only a single or double phase CT failure can be detected by this logic. The probability of symmetrical three-phase CT failures is very low, therefore in practice this is not a significant problem.

2.5 Circuitry Fail Alarm

The circuitry fail alarm logic requires the following settings: **Is-cctfail>**, **K-cctfail** and **Cct Fail Delay**. If the differential current is bigger than **Is-cctfail>** setting and not trip is issued after the **tIs-cctfail>** time delay has elapsed, an alarm would be issued indicating a CT problem.

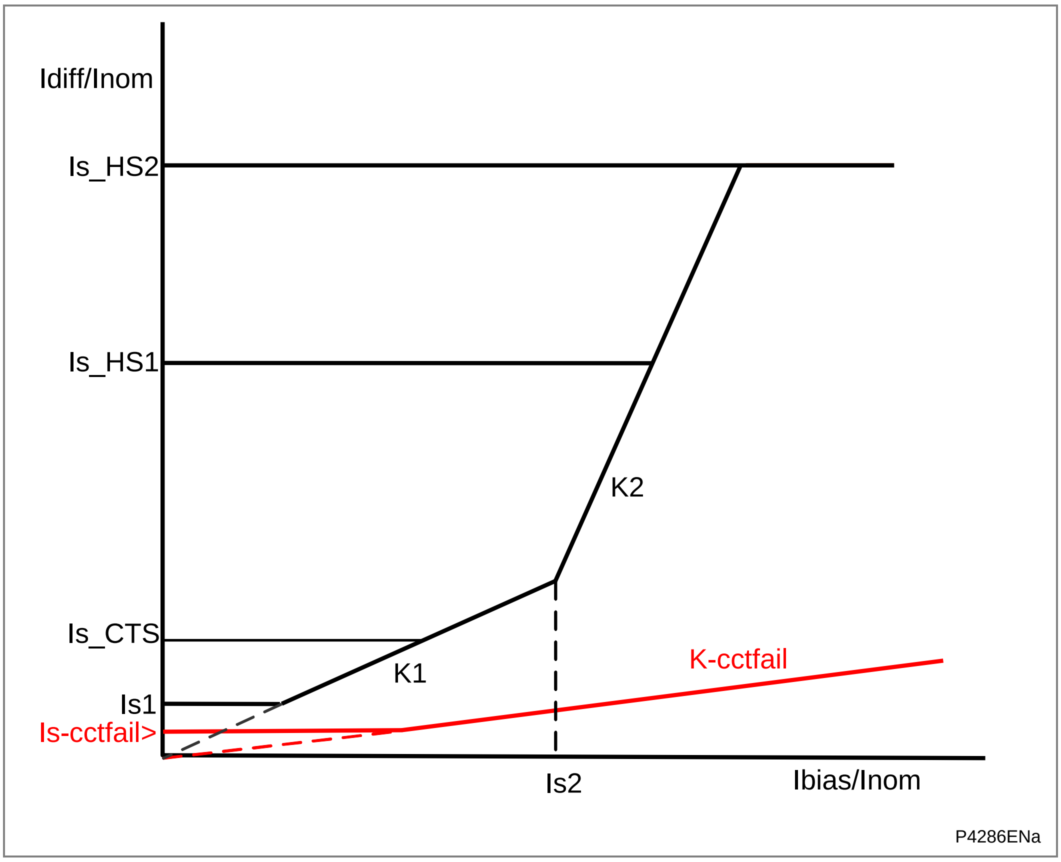


Figure 90 - Circuitry fail alarm fault characteristic

2.6 Circuit Breaker State Monitoring

An operator at a remote location requires a reliable indication of the state of the switchgear. Without an indication that each circuit breaker is either open or closed, the operator has insufficient information to decide on switching operations. 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.

2.6.1 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 these 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.

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 26 - CB status logic

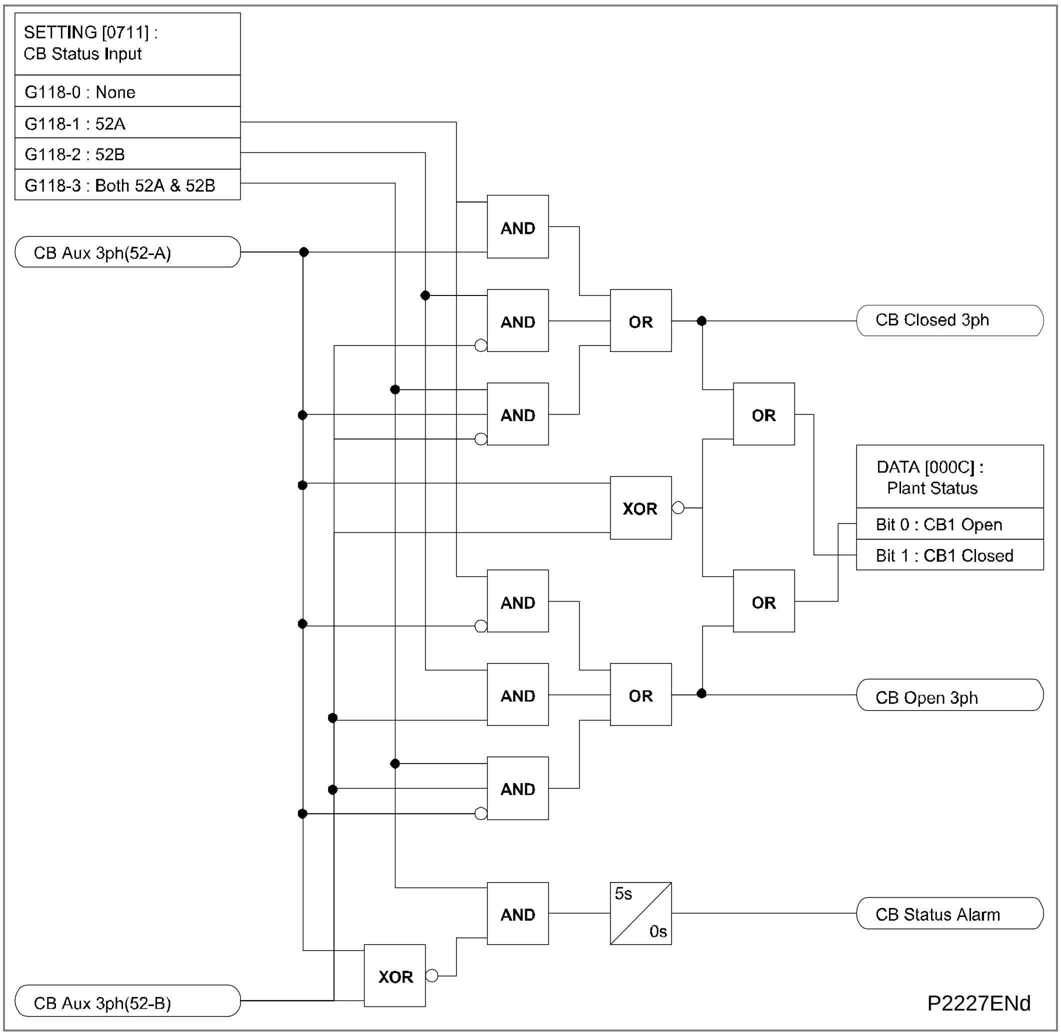


Figure 91 - CB state monitoring

2.7 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 underfrequency, undervoltage and power elements. The undervoltage 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**. The Power and Sensitive Power protection will be blocked by a pole dead condition provided the **Pole Dead Inhibit** setting is enabled.

A pole dead condition can be 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 1042) 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 undervoltage (V<) and undercurrent (I<) thresholds have the following, fixed, pickup and drop-off levels:

Settings	Range	Step size
V< Pick-up and drop off	10 V and 30 V (100/120 V) 40 V and 120 V (380/480 V)	Fixed
I< Pick-up and drop off	0.05 In and 0.055 In	Fixed

Table 27 - Pole dead logic

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 1285). If all phases were dead the ANY POLE DEAD signal would be accompanied by the ALL POLE DEAD DDB signal (DDB 1285).

In the event that the VT fails a signal is taken from the VTS logic (DDB 1249 - Slow Block) to block the pole dead indications that would be generated by the undervoltage and undercurrent thresholds. However, the VTS logic will not block the pole dead indications if they are initiated by a **CB Open** signal (DDB 1282).

The pole dead logic diagram is shown in in this diagram:

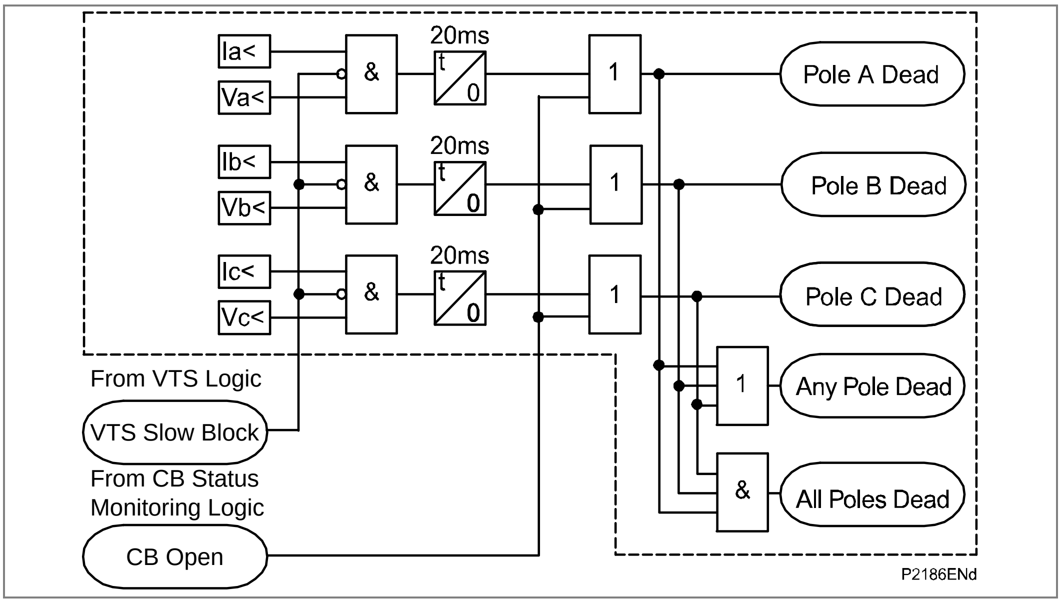


Figure 92 - Pole dead logic

2.8 Circuit Breaker Condition Monitoring

The relay records 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.

2.8.1 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	0	0	10000	1
Displays the total number of trips issued by the relay.				
Total IA Broken	0	0	25000 In^	1
Displays the total accumulated fault current interrupted by the relay for the A phase.				
Total IB Broken	0	0	25000 In^	1
Displays the total accumulated fault current interrupted by the relay for the A phase.				
Total IC Broken	0	0	25000 In^	1 In^
Displays the total accumulated fault current interrupted by the relay for the A phase.				
CB Operate Time	0	0	0.5 s	0.001
Displays the calculated CB operating time. CB operating time = time from protection trip to undercurrent elements indicating the CB is open.				
Reset All Values	No		Yes, No	
Reset CB Data command. Resets CB Operations and Total IA/IB/IC broken current counters to 0.				

Table 28 - CB condition monitoring 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 (using the programmable scheme logic) to accept a trigger from an external device. The signal that is mapped to the opto is called **Ext. Trip 3Ph**, DDB 610.

Note	*When in **Commissioning Test Mode** the CB condition monitoring counters will not be updated.*

2.9 Circuit Breaker Control

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

- Local tripping and closing, via the relay menu
- 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. Where this feature is not required the same output contact(s) can be used for both protection and remote tripping.

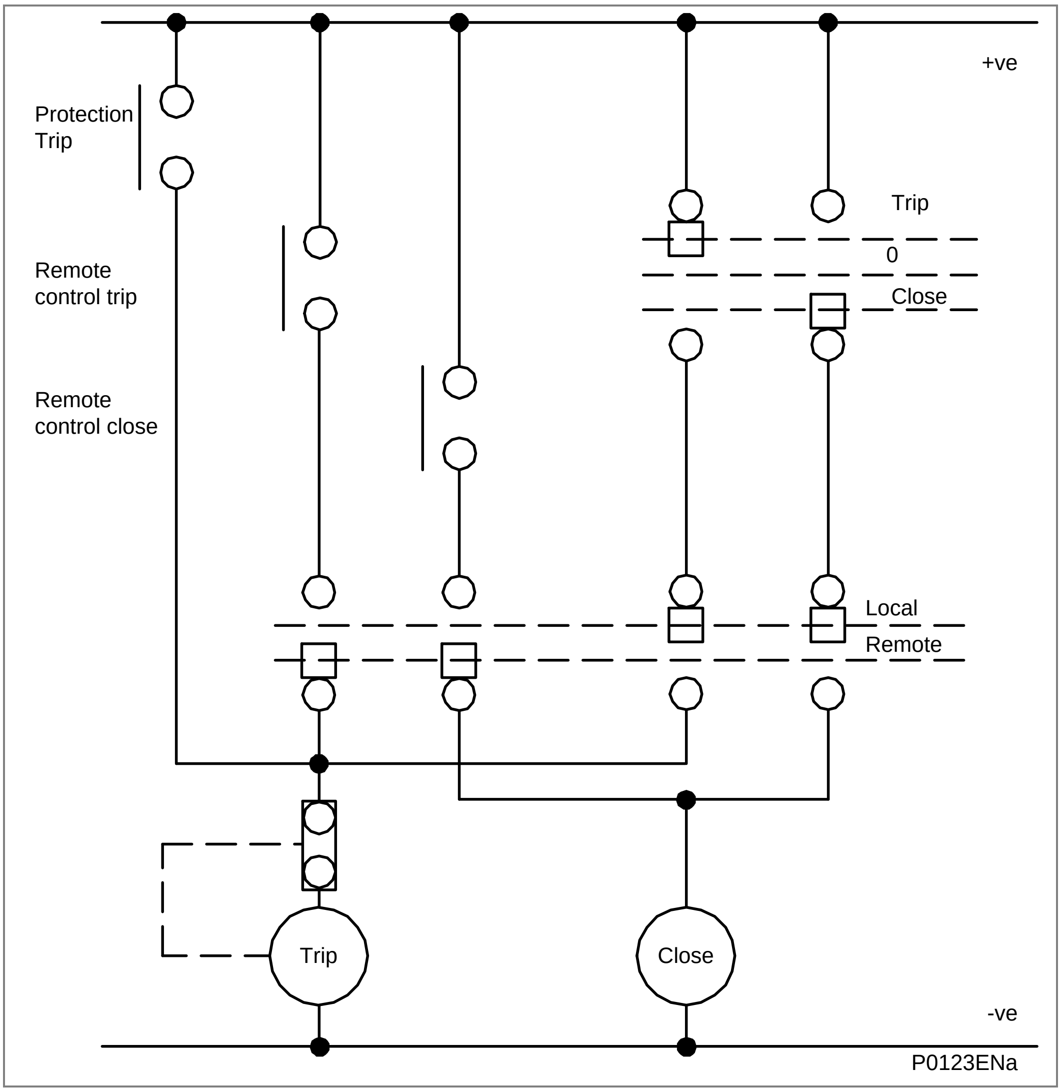


Figure 93 - Remote control of circuit breaker

The *CB control settings* table is taken from the relay menu and shows the available settings and commands associated with circuit breaker control. Depending on the relay model some of the cells may not be visible:

Menu text	Default setting	Setting range		Step size
		Min.	Max.	
CB control				

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+Rem+Local		
Close Pulse Time	0.5 s	0.01 s	10 s	0.01 s
Trip Pulse Time	0.5 s	0.01 s	5 s	0.01 s
Man Close Delay	10 s	0.01 s	600 s	0.01 s
CB Healthy Time	5 s	0.01 s	9999 s	0.01 s
Lockout Reset	No	No, Yes		
Reset Lockout By	CB Close	User Interface, CB Close		
Man Close RstDly	5 s	0.01 s	600 s	0.01 s
CB Status Input	None	None, 52A, 52B, Both 52A and 52B		

Table 29 - CB control settings

A manual trip will be possible if the circuit breaker is closed. Likewise, a close command can only be issued if the CB is open.

Therefore, it will be necessary to use the breaker positions 52A and/or 52B contacts via the PSL (the different selection options are given from the **CBx Status Input** cell above). If no CB auxiliary contacts are available, this cell should be set to **None**. Under these circumstances no circuit breaker 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 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	*CB close command is in the '**System Data**' column ('**CB Trip/Close**' cell).*

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.

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).

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).

The lockout alarms can be reset using the **Lockout Reset** command or the by pressing the Clear key after reading the alarm or by closing the CB if the **Reset Lockout By** setting is set to **CB Close** or via an opto input using DDB 690, Reset Lockout. If lockout is reset by closing the CB then there is a time delay after closing the CB to resetting of lockout, the **Man Close RstDly**.

2.9.1 CB Control using Hotkeys

The hotkeys allow direct access to the manual trip and close commands without the need to use the SYSTEM DATA menu column. The CB trip and close functionality via the hotkey menu is identical to that of the SYSTEM DATA menu.

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 displaying the circuit breaker 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. If the command has been executed, a screen confirming the present status of the circuit breaker will be displayed. The user is then prompted to select the next appropriate command or to exit - this will return to the default relay screen.

If no keys are pressed for a period of 25 seconds whilst the relay is waiting for the command confirmation, the relay will revert to showing the circuit breaker status. If no key presses are made for a period of 25 seconds whilst the relay is displaying the circuit breaker status screen, the relay will revert to the default relay screen. The *Circuit breaker control hotkey menu* diagram shows the hotkey menu associated with circuit breaker control functionality.

To avoid accidental operation of the trip and close functionality, the hotkey circuit breaker control commands are disabled for 10 seconds after exiting the hotkey menu.

2.10 Changing Setting Groups

The setting groups can be changed either via 2 DDB signals or via a menu selection selection or via the hotkey menu. In the Configuration column if **Setting Group - select via DDB** is selected then DDBs 676 (SG Select 1x) and 675 (SG Select x1), which are dedicated for setting group selection, can be used to select the setting group as shown in the table below. These DDB signals can be connected to opto inputs for local selection or control inputs for remote selection of the setting groups. 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.

SG select 1x	SG select x1	Selected setting group
0	0	1
1	0	2
0	1	3
1	1	4

Table 30 - Setting group selection logic

Note	*Setting groups comprise both Settings and Programmable Scheme Logic (PSL). Each is independent per group - not shared as common. The settings are generated in the Settings and Records application within S1 Studio, or can be applied directly from the relay front panel menu. The PSL can only be set using the PSL Editor application within S1 Studio, generating files with extension ".psl".*

It is essential that where the installation needs application-specific PSL that the appropriate .psl file is downloaded (sent) to the relay, for each and every 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, then factory default PSL will still be resident. This may have severe operational and safety consequences.

2.11 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 31 - 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 which can be set to a logic 1 or On state, as described above, are available to perform control functions defined by the user.

In the PSL editor 32 Control Input signals, use DDB 1152 – 1183.

The status of the Control Inputs are held in non-volatile memory (battery backed RAM) such that when the relay is power-cycled, the states are restored upon power-up.

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 32 - Control input configuration

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 33 - Control input 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	*With the exception of pulsed operation, the status of the control inputs is stored in battery backed memory. In the event that the auxiliary supply is interrupted the status of all the inputs will be recorded. Following the restoration of the auxiliary supply the status of the control inputs, prior to supply failure, will be reinstated. If the battery is missing or flat the control inputs will set to logic 0 once the auxiliary supply is restored.*

2.12 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.*

2.13 Auto Reset of Trip LED Indication

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 reclosed and the **Any Pole Dead** signal (DDB 1045) has been reset for three seconds. Resetting, however, will be prevented if the **Any start** signal is active after the breaker closes.

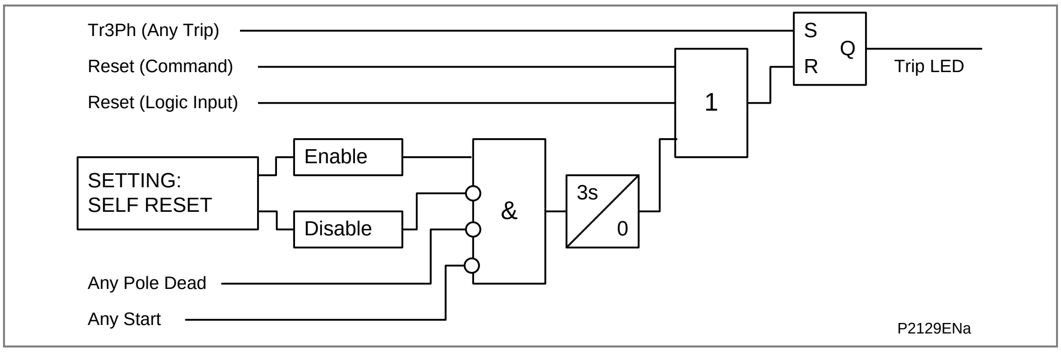


Figure 94 - Trip LED logic diagram

2.14 Reset of Programmable LEDs and Output Contacts

The programmable LEDs and output contacts can be set to be latched in the Programmable Scheme Logic. If there is a fault record, then clearing the fault record by pressing the Ⓒ key once the fault record has been read will clear any latched LEDs and output contacts. If there is no fault record, then as long as the initiating signal to the LED or output contact is reset the LEDs and contacts can be reset by one of these methods.

- Via the **View Records - Reset Indications** menu command cell
- Via DDB 116 **Reset Latches** which can be mapped to an Opto Input or a Control Input for example

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, if fitted, or via the communication interface connected to the substation control system. In addition to these methods the relay offers the facility to synchronize via an opto-input by routing it in PSL to DDB 621 (Time Sync.). Pulsing this input will result in the real time clock snapping to the nearest minute if the pulse input is ± 3 s of the relay clock time. If the real time clock is within 3 s of the pulse the relay clock will crawl (the clock will slow down or get faster over a short period) to the correct time. The recommended pulse duration is 20 ms to be repeated no more than once per minute. An example of the time sync. function is shown in the following table:

Time of “Sync. Pulse”	Corrected time	
19:47:00 to 19:47:29	19:47:00	This assumes a time format of hh:mm:ss
19:47:30 to 19:47:59	19:48:00	

Table 34 - Time sync example

To avoid the event buffer from being filled with unnecessary time sync. events, it is possible to ignore any event that 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
DDB 63 – 32 (Opto Inputs)	Set “Time Sync.” associated opto to 0

Table 35 - Event filtering of time sync signal

To improve the recognition time of the time sync. opto input by approximately 10 ms, the opto input filtering could be disabled. This is achieved by setting the appropriate bit to 0 in the **Opto Filter Cntl** cell in the **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.

2.16 Any Trip

The **Any Trip** DDB (DDB674) has been made independent from Relay 3 in the version 32 software. In previous versions of software the **Any Trip** signal was the operation of Relay 3. In the version 32 software DDB626 is the **Any Trip** signal and any output contact used for tripping can be connected to the **Any Trip** DDB leaving Relay 3 to be freely assigned for any function. The **Any Trip** signal affects these functions:

- Operates the Trip LED
- Triggers CB condition maintenance counters
- Used to measure the CB operating time
- Triggers the circuit breaker failure logic
- Used in the Fault recorder logic

In the default PSL, Relay 3 is still mapped to the **Any Trip** DDB and the **Fault REC TRIG** DDB signals. If the user wants to make use of the CB maintenance features, CB failure function etc they should map the output contact(s) assigned for tripping the monitored circuit breaker to the **Any Trip** DDB. The output contact(s) assigned for tripping the monitored circuit breaker should also be connected to the fault record trigger **Fault REC TRIG** DDB 623 for fault record triggering.

Where relay 3 or any other contact is used to initiate the **Any Trip** signal the contact should not be set to latched as the **Any Trip** is used to trigger (on pick-up) and reset (on drop-off) the fault recorder window. So if the **Any Trip** is latched the fault recording window never resets and so you won’t see a fault record on the relay front display as the relay thinks the fault is still present.

The default setting for relay 3 is a dwell time of 100 ms, a dwell is the minimum time the contact will be ON and is used for trip functions to ensure a good quality trip signal is obtained. As an example of a dwell timer, a dwell of 100 ms means that if the initiating signal is ON for 10 ms then the output contact is ON for 100 ms and if the initiating signal is ON for 200 ms then the output contact is ON for 200 ms.

2.17 Function Keys (P343/P344/P345)

The relay offers users 10 function keys for programming any operator control functionality via PSL. Each function key has an associated programmable tri-colour 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 the Settings chapter). 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, 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.

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.*

2.18 Read Only Mode

With IEC 61850 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 IEC 61850 protocol options. In IEC 60870-5-103 protocol, Read Only Mode function is different from the existing Command block feature.

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 (“tunneled”)

Notes:

APPLICATION NOTES

CHAPTER 6

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

CONTENTS

FIGURES

TABLES

1 INTRODUCTION

1.1 Protection of Generators

An ac generator forms the electromechanical stage of an overall energy conversion process that results in the production of electrical power. A reciprocating engine, or one of many forms of turbine, is a prime mover to provide the rotary mechanical input to the alternator.

There are many forms of generating plant that use different sources of energy such as combustion of fossil fuels, hydro dams and nuclear fission. Generation schemes may be provided for base-load production, peak-lopping or for providing standby power.

Electrical protection should quickly detect and initiate shutdown for major electrical faults associated with the generating plant. Electrical protection can also detect abnormal operating conditions which may lead to plant damage.

Abnormal electrical conditions can be caused by a result of a failure in the generating plant, but can also be externally imposed on the generator. Common categories of faults and abnormal conditions that can be detected electrically are listed as follows: (Not all conditions have to be detected for all applications)

Major electrical faults

- Insulation failure of stator windings or connections

Secondary electrical faults

- Insulation failure of excitation system
- Failure of excitation system
- Unsynchronized over voltage
- Abnormal prime mover or control conditions

Failure of prime mover

- Dead machine energization
- Breaker flashover
- System related
- Feeding an uncleared fault
- Prolonged or heavy unbalanced loading
- Prolonged or heavy overload
- Loss of synchronism
- Overfrequency
- Underfrequency
- Synchronized over voltage
- Overfluxing
- Undervoltage

In addition, various types of mechanical protection may be necessary, such as vibration detection, lubricant and coolant monitoring, temperature detection etc.

The action required following response of an electrical or mechanical protection is often categorized as follows:

- Urgent shutdown
- Non-urgent shutdown
- Alarm only

An urgent shutdown would be required, for example, if a phase to phase fault occurred within the generator electrical connections. A non-urgent shutdown might be sequential, where the prime mover may be shutdown prior to electrically unloading the generator, in order to avoid over speed. A non-urgent shutdown may be initiated in the case of continued unbalanced loading. In this case, it is desirable that an alarm should be given before shutdown becomes necessary, to allow for operator intervention to remedy the situation.

For urgent tripping, it may be desirable to electrically maintain the shutdown condition with latching protection output contacts, which would require manual resetting. For a non-urgent shutdown, it may be required that the output contacts are self-reset, so that production of power can be re-started as soon as possible.

The P34x relay is able to maintain all protection functions in service over a wide range of operating frequency due to its frequency tracking system (5-70 Hz). The P34x relay frequency tracking capability is of particular interest for pumped storage generation schemes, where synchronous machines can be operated from a variable frequency supply when in pumping mode. Additionally, in the case of combined cycle generating plant, it may be necessary to excite and synchronize a steam turbine generating set with a gas turbine set at low frequency, prior to running up to nominal frequency and synchronizing with the power system.

When the P34x relay protection functions are required to operate accurately at low frequency, it will be necessary to use CTs with larger cores. In effect, the CT requirements need to be multiplied by fn/f, where f is the minimum required operating frequency and fn is the nominal operating frequency.

1.2 Protection of Generator-Transformers

1.2.1 Introduction

The development of modern power systems has been reflected in the advances in transformer design. This has resulted in a wide range of transformers with power rating from a few kVA to several hundred MVA being available for use in a wide variety of applications.

The considerations for transformer protection vary with the application and importance of the transformer. To reduce the effects of thermal stress and electrodynamic forces, the overall protection should minimize the time that a fault is present within a transformer.

On smaller distribution transformers, effective and economically justifiable protection can be achieved by using either fuse protection or IDMT/instantaneous overcurrent relays. Due to the requirements of co-ordination with the downstream power system protection, this results in time-delayed fault clearance for some low-level faults. Time delayed clearance of major faults is unacceptable on larger distribution, transmission and generator transformers, where the effects on system operation and stability must be considered. High speed protection is desirable for all faults.

Transformer faults are generally classified into these categories:

- Winding and terminal faults
- Core faults
- Abnormal operating conditions such as overvoltage, overfluxing and overload
- Sustained or uncleared external faults

All of the above conditions must be considered individually and the transformer protection designed accordingly.

To provide effective protection for faults within a transformer and security for normal operation and external faults, the design and application of transformer protection must consider factors such as:

- Magnetizing inrush current
- Winding arrangements
- Winding connections
- Connection of protection secondary circuits

The way that the protection of larger transformers is typically achieved is best illustrated by examining the protective devices associated with common applications.

1.2.2 Transformer Connections

There are several possible transformer connections but the more common connections are divided into the main groups shown in the following table:

Group	Phase displacement	Transformer connections
Group 1	0° Phase displacement	Yy0 or Dz0 or Dd0
Group 2	180° Phase displacement	Yy6 or Dd6 or Dz6
Group 3	30° lag Phase displacement	Dy1 or Yz1 or Yd1
Group 4	30° lead Phase displacement	Yd11 or Dy11 or Yz11

High voltage windings use capital letters and low voltage windings by lower-case letters (reference to high and low is relative). The numbers refer to positions on a clock face and indicate the phase displacement of the low voltage phase to neutral vector with respect to the high voltage phase to neutral vector. For example, Yd1 indicates that the low voltage phase vectors lag the high voltage phase vectors by 30° (-30° phase shift).

Determining transformer connections is best shown with a particular example. These points should be noted:

- The line connections are normally made to the end of the winding which carries the subscript $_2$, such as: A_2, B_2, C_2 and a_2, b_2, c_2.
- The line terminal designation (both letter and subscript) are the same as those of the phase winding to which the line terminal is connected.

Consider the Yd1 connection. The transformer windings shown in the following diagram should be connected in Yd1 configuration.

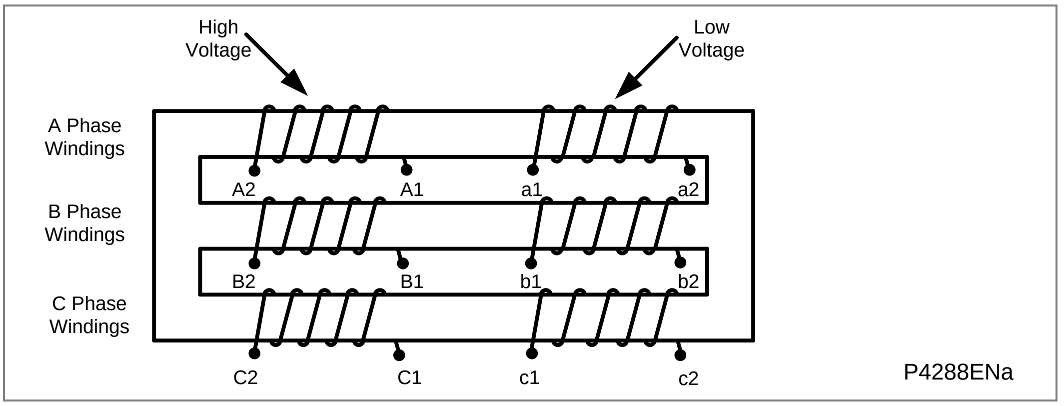


Figure 1 - Transformer windings to be connected in Yd1 configuration

Follow these steps to connect the transformer windings:

1. Draw the primary and secondary phase to neutral vectors showing the required phase displacement.

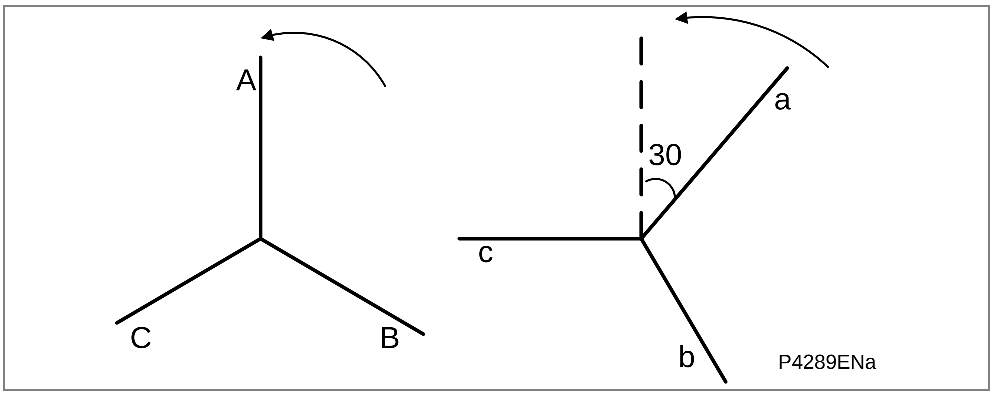


Figure 2 - Phase-neutral voltage vectors

1. Complete the delta winding connection on the secondary side and indicate the respective vector directions. Magnetically coupled windings are drawn in parallel, winding “A” in the star side is parallel to winding “a” in the delta side. The same applies for the other two phases.

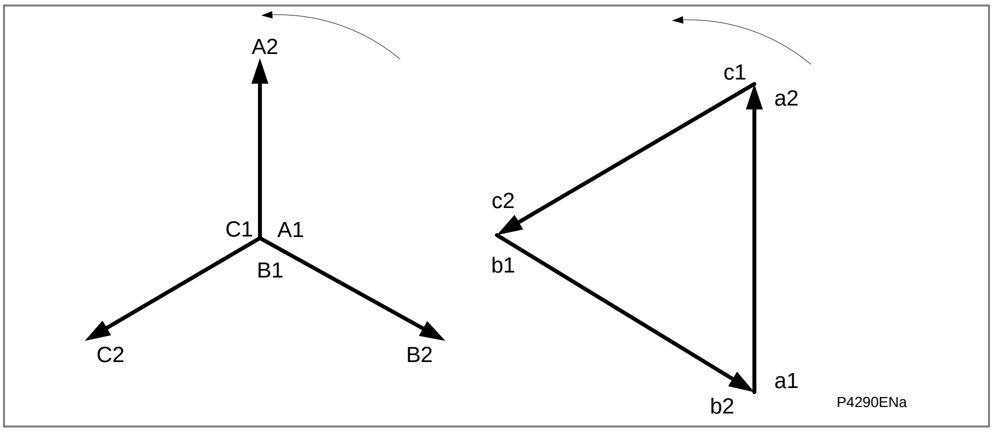


Figure 3 - Draw the delta

1. It is now possible to indicate the winding subscript numbers bearing in mind that if the direction of induced voltage in the high voltage winding at a given instant is from A1 to A2 (or vice versa) then the direction of the induced voltage in the low voltage winding at the same instant will also be from a1 to a2.
1. The delta connection should be made by connecting a2 to c1, b2 to a1 and c2 to b1:

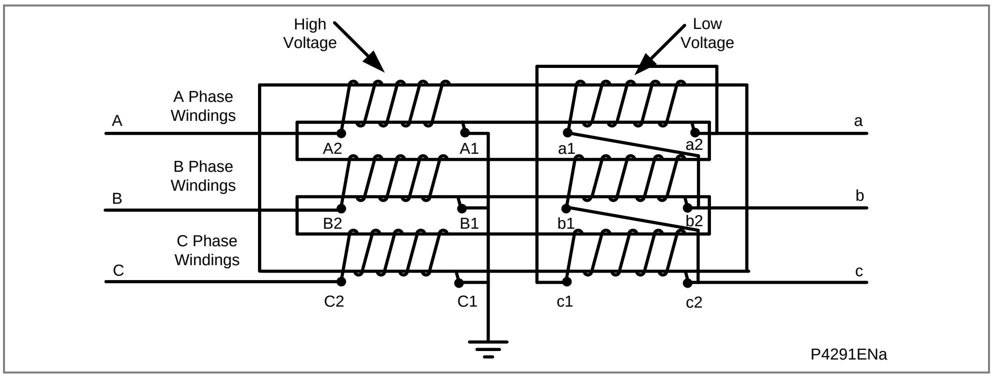


Figure 4 - Yd1 transformer configuration

1.2.3 Generator-Transformer Example

The following diagram shows typical protection functions for a generator-transformer.

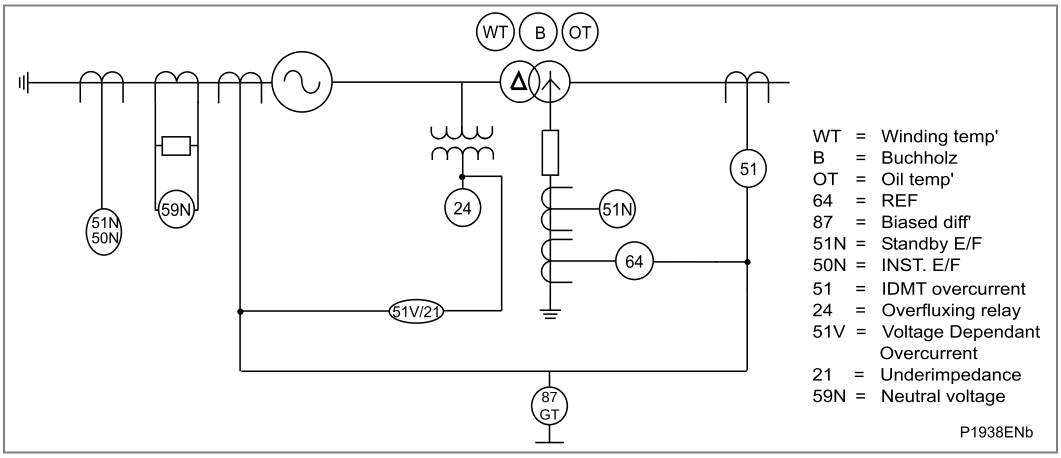


Figure 5 - Typical protection package for a generator-transformer

High speed protection is provided for faults on both the HV and LV windings by biased differential protection (87). The relay operates on the basic differential principle that HV and LV CT secondary currents entering and leaving the zone of protection can be balanced under load and through fault conditions, whereas under internal fault conditions balance will be lost and a differential current will cause the relay to trip. The zone of protection is clearly defined by the CT locations and, as the protection is stable for through faults, it can be set to operate without any intentional time delay.

The application of this differential relay includes software vector group and amplitude matching to provide phase and ratio correction of CT signals in addition to filtering HV zero sequence current to prevent maloperation of the differential element for external HV earth faults. Interposing CTs (ICTs) are no longer required.

More sensitive high speed earth fault protection for the HV star winding is provided by restricted earth fault protection (64). Due to the limitation of phase fault current on the LV side for HV winding earth faults and the fact that any unrestricted earth fault protection in the transformer earth path requires a discriminative time delay, restricted earth fault protection is widely applied.

Earth fault protection is provided on the LV winding and generator by the inherently restricted earth fault protection on the generator. This could be neutral voltage (59N) or current based earth fault protection (50 N) depending on how the generator is earthed. The delta winding of the transformer draws no LV zero sequence current for HV earth faults, hence there is no requirement to grade this element with other earth fault protection and it can be set to operate without any intentional time delay. For delta windings this is known as balanced earth fault protection.

Sustained external HV faults are cleared by the IDMT overcurrent protection (51) on the HV winding or IDMT voltage dependent overcurrent protection or underimpedance protection on the LV winding/generator (51 V/21) or by the standby earth fault protection (51N) in the transformer HV earth connection. The extent of backup protection used will vary according to the transformer installation and application.

Overfluxing protection (24) is commonly applied to generator circuits to prevent generator or transformer damage from prolonged overfluxing conditions.

The protection scheme may be further enhanced by the use of other protective devices associated with the transformer, such as the Buchholz, pressure relief and winding temperature devices. These devices can act as another main protective system for large transformers and they may also provide clearance for some faults which might be difficult to detect by protection devices operating from line current transformers, for example, winding inter turn faults or core lamination faults. These devices are connected to directly trip the breaker in addition to operating auxiliary relays for indication purposes.

Other protection devices will again complement the main relay 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. Each section also gives an extract from the respective menu columns to demonstrate how the settings are actually applied to the relay.

All the phase current based protection functions (overcurrent, power, impedance protection) use the IA/IB/IC 3 phase current inputs which are connected to the neutral end CTs in the standard connection diagrams except for the high impedance differential and interturn protection which use the IA-2/IB-2/IC-2 current inputs. The overcurrent, restricted earth fault, NPS overcurrent, dead machine protection and CB Fail undercurrent elements can use the IA/IB/IC or IA-2/IB-2/IC-2 current inputs selectable in the settings. The biased differential protection uses both sets of 3 phase current inputs.

2.1 Phase Rotation

2.1.1 Description

A facility is provided in the relay to maintain correct operation of all the protection functions even when the generator is running in a reverse phase sequence. This is achieved through user configurable settings available for the four setting groups.

The default phase sequence for relay is the clockwise rotation ABC. Some power systems may have a permanent anti-clockwise phase rotation of ACB. In pump storage applications there is also a common practice to reverse two phases to facilitate the pumping operation, using phase reversal switches. However, depending on the position of the switches with respect to the VTs and CTs, the phase rotation may not affect all the voltage and current inputs to the relay. The following sections describe some common scenarios and their effects.

For pump storage applications the correct phase rotation settings can be applied for a specific operating mode and phase configuration in different setting groups. The phase configuration can then be set by selecting the appropriate setting group, see the ***Operation*** chapter for more information of changing setting groups. This method of selecting the phase configuration removes the need for external switching of CT circuits or the duplication of relays with connections to different CT phases. The phase rotation settings should only be changed when the machine is off-line so that transient differences in the phase rotation between the relay and power system due to the switching of phases don’t cause operation of any of the protection functions. To ensure that setting groups are only changed when the machine is off-line the changing of the setting groups could be interlocked with the IA/IB/IC undercurrent start signals and an undervoltage start signal in the PSL.

2.1.1.1 Case 1 – Phase Reversal Switches affecting all CTs and VTs

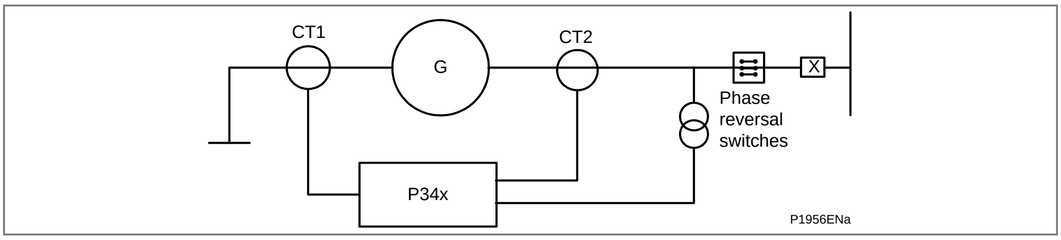


Figure 6 - Case 1 - phase reversal switches affecting all CTs and VTs

The phase reversal affects all the voltage and current measurements in the same way, irrespective of which two phases are being swapped. This is also equivalent to a power system that is permanently reverse phase reversed.

All the protection functions that use the positive and negative sequence component of voltage and current will be affected (NPS overcurrent and NPS overvoltage, thermal overload, voltage transformer supervision). Directional overcurrent is also affected as the polarizing signal (Vbc, Vca, Vab) is reversed by the change in phase rotation. The generator differential protection is not affected, since the phase reversal applies to CT1 and CT2 in the same way.

The relationship between voltages and currents from CT1 for the standard phase rotation and reverse phase rotation are as shown below.

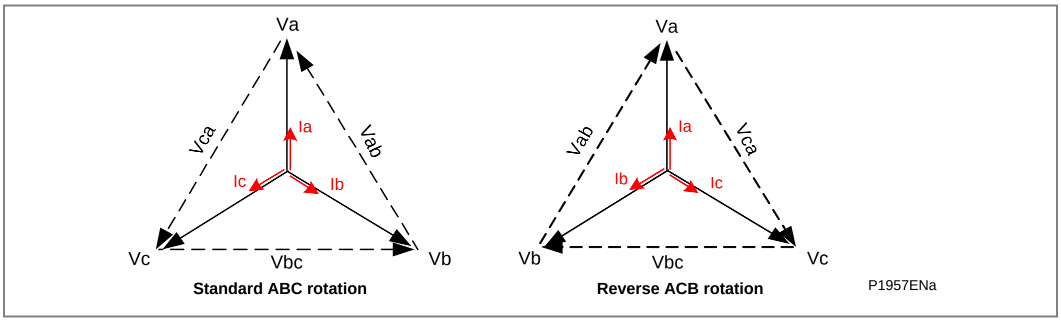


Figure 7 - Standard and reverse phase rotation

In the above example, the System Config settings - Standard ABC and Reverse ACB can be used in 2 of the Setting Groups to affect the phase rotation depending on the position of the phase reversal switch.

2.1.1.2 Case 2 – Phase Reversal Switches affecting CT1 only

The phase reversal affects CT1 only. All the protection functions that use CT1 currents and the 3 phase voltages (power, pole slipping, field failure, underimpedance, voltage controlled overcurrent, directional overcurrent) will be affected, since the reversal changes the phase relationship between the voltages and currents. The generator differential protection and protection that use positive and negative sequence current and voltage will also be affected.

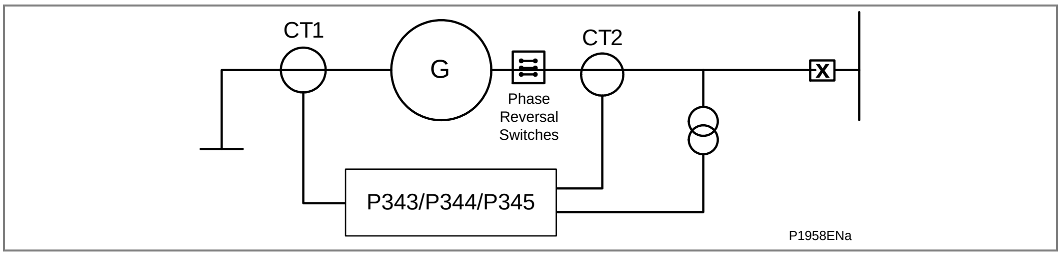


Figure 8 - Case 2 - phase reversal switches affecting CT1 only

Note	*There are 2 approaches to using the System Config settings where 2 phases are swapped. The settings can be used to maintain a generator view of the phase sequence or a system (or busbar) view of the phase sequence for a generator fault.*

For example, in Case 2, for a generator A-phase winding fault, the relay will report a B phase fault if the CT1 Reversal setting is set to A-B Swapped (system or busbar view of faulted phase). For a busbar fault the correct faulted phase will be given in the fault record.

In the above example, instead of swapping A-B phase of CT1, the user can alternatively set A-B Swapped for CT2 Reversal and the VT Reversal and apply the Phase Sequence setting to Reverse ACB. With this approach, internal faults (e.g., A-phase winding fault) will give the correct phase information in the fault records (generator view of faulted phase), whereas an external A-phase fault will be presented as a B-phase fault.

So, to obtain a phase sequence maintaining a generator viewpoint for a generator fault the CTs/VTs not affected by the change must have the phase swapping setting to match the external switching. Also, since the machine's sequence rotation has been affected, the Phase Sequence setting will also need to be applied accordingly.

To obtain a phase sequence maintaining a system viewpoint for a generator fault the CTs/VTs affected by the change must have the phase swapping setting to match the external switching.

The Sensitive Power is a single phase power element; one of three phases could be selected. If phase ϕ (ϕ= A, B or C if setting Phase Select = A, B or C) was selected, the current $I\phi$ and voltage $V\phi$ was used. If Sensitive Power is applied and the ϕ phase current only has been swapped, the power calculation will be wrong since the voltage and current inputs are not from the same phase. If for example in Case 2 the A-B phases are swapped and the sensitive CT is on the generator side of the switch. It is possible to use the alternative approach where the CT2 and VT phases are swapped so that the ϕ -phase voltage (from generator's view point) is restored for the correct calculation of the ϕ -phase power. This problem cannot be resolved with the other approach where only CT1 phases are swapped, therefore the protection will need to be disabled or the phase reversal switches arranged such that the ϕ -phase is not swapped or the sensitive power CT placed on the same side of the switch as the VT.

2.2 Generator Differential Protection (87G)

Failure of stator windings, or connection insulation, can result in severe damage to the windings and the stator core. The extent of the damage will depend on the fault current level and the duration of the fault. Protection should be applied to limit the degree of damage in order to limit repair costs. For primary generating plant, high-speed disconnection of the plant from the power system may also be necessary to maintain system stability.

For generators rated above 1 MVA, it is common to apply generator differential protection. This form of unit protection allows discriminative detection of winding faults, with no intentional time delay, where a significant fault current arises. The zone of protection, defined by the location of the CTs, should be arranged to overlap protection for other items of plant, such as a busbar or a step-up transformer.

Heavy through current, arising from an external fault condition, can cause one CT to saturate more than the other, resulting in a difference between the secondary current produced by each CT. It is essential to stabilize the protection for these conditions. Two methods are commonly used. A biasing technique, where the relay setting is raised as through current increases. Alternatively, a high impedance technique, where the relay impedance is such that under maximum through fault conditions, the current in the differential element is insufficient for the relay to operate.

The generator differential protection function available in the P343/P344/P345 relay can be used in either biased differential or high impedance differential mode. Both modes of operation are equally valid; users may have a preference for one over the other. The generator differential protection may also be used for interturn protection. The operating principle of each is described in the Operation chapter.

2.2.1 Setting Guidelines for Biased Generator Differential Protection

The differential setting, Configuration - Differential, should be set to Enabled. If the winding type in the SYSTEM CONFIG - Winding Config is set to Generator, then the settings related to Generator differential protection will be displayed in the column DIFFERENTIAL - Generator Diff.

To select biased differential protection, the Gen Diff Func cell should be set to Percentage Bias.

The differential current setting, Gen Diff Is1, should be set to a low setting to protect as much of the machine winding as possible. A setting of 5% of rated current of the machine is generally considered to be adequate. Gen Diff Is2, the threshold above which the second bias setting is applied, should be set to 120% of the machine rated current.

The initial bias slope setting, Gen Diff k1, should be set to 0% to provide optimum sensitivity for internal faults. The second bias slope may typically be set to 150% to provide adequate stability for external faults.

Note	*The default settings for Gen Diff Is2 (1.2 In), Gen Diff K1 (0%) and Gen Diff K2 (150%) should always be used as the CT requirements are based on these settings.*

2.2.2 Setting Guidelines for High Impedance Generator Differential Protection

The differential setting, Configuration - Differential, should be set to Enabled. If the winding type in the SYSTEM CONFIG - Winding Config is set to Generator, then the settings related to Generator differential protection will be displayed in the column DIFFERENTIAL - Generator Diff.

To select high impedance differential protection, the Gen Diff Func cell should be set to High Impedance.

The differential current setting, Gen Diff Is1, should be set to a low setting to protect as much of the machine winding as possible. A setting of 5% of rated current of the machine is generally considered to be adequate. This setting may need to be increased where low accuracy class CTs are used to supply the protection. A check should be made to ensure that the primary operating current of the element is less than the minimum fault current for which the protection should operate.

The primary operating current (Iop) will be a function of the current transformer ratio, the relay operating current (Gen Diff 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.

$$I_e < \frac{1}{n} \text{ x} \left(\frac{I_{op}}{\text{CT ratio}} - \text{Gen Diff REF} > I_s1 \right)$$

1. To determine the maximum relay current setting to achieve a specific primary operating current with a given current transformer magnetizing current.

$$\text{Gen Diff.}I_s1 < \left(\frac{I_{op}}{\text{CT.Ratio}} - nI_e \right)$$

1. To express the protection primary operating current for a particular relay operating current and with a particular level of magnetizing current.

I_{OP} = (CT.Ratio) x (Gen Diff Is1 + nI_e)

To achieve the required primary operating current with the current transformers that are used, a current setting (Gen Diff Is1) must be selected for the high impedance element, as detailed in expression (ii) above. The setting of the stabilizing resistor (R_{ST}) 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 (Gen Diff Is1).

$$R_{st} = \frac{V_s}{\text{Gen Diff } I_s1} = \frac{1.5 \text{ x } I_F (R_{CT} + 2RL)}{\text{Gen Diff } I_s1}$$

Note	*The above formula assumes negligible relay burden.*

2.2.2.1 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.

This prospective voltage will be a function of maximum internal fault secondary current, the current transformer ratio, the current transformer secondary winding resistance, the current transformer lead resistance to the common point, the relay lead resistance and the stabilizing resistor value.

$$Vp = 2 \sqrt{2V_k (V_f - V_k)}$$

$V_f = I'_f (R_{ct} + 2R_L + R_{ST})$

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 these requirements:

- 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.
- 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.

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:

1. At the relay voltage setting, the Metrosil current should be less than 30 mA rms.
2. At the maximum secondary internal fault current the Metrosil unit should limit the voltage to 1500 V 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.*

Table 1 - Recommended Metrosil types for 1A CTs

Metrosil units for relays with a 5 amp CT

These Metrosil units have been designed to comply with these requirements:

- 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.
- 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 *, **, ***).

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/S1221 C = 570/670** 100 mA rms	600 A/S3/P/S1222 C =620/740*** 100 mA rms
Note:			**2200 V peak	*2400 V peak ***2600 V peak

Table 2 - Recommended Metrosil types for 5 A CTs

In some situations single disc assemblies may be acceptable, contact Schneider Electric for detailed applications.

1. The Metrosil units recommended for use with 5 Amp CTs can also be applied for usewith 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.
2. Metrosil units for higher relay voltage settings and fault currents can be supplied if required.
3. To express the protection primary operating current for a particular relay operating current and with a particular level of magnetizing current.

For further advice and guidance on selecting Metrosils please contact the Applications department at Schneider Electric.

2.2.3 Interturn (Split Phase) Protection

For generators with multi-turn stator windings, there is the possibility of a winding inter-turn fault occurring. Unless such a fault evolves to become a stator earth fault, it will not otherwise be detected with conventional protection arrangements. Hydro generators usually involve multi-stator windings with parallel windings.

2.2.3.1 Generator Differential Interturn Protection

One differential scheme using bushing type CTs that is commonly used for interturn protection is shown in the *Generator interturn protection using separate CTs* diagram. In this scheme the circuits in each phase of the stator winding are split into two equal groups and the current of each group are compared. A difference in these currents indicates an unbalance caused by an interturn fault. Since there is normally some current unbalance between windings the protection is set so that it will not respond to this normal unbalance but will pick-up for the unbalance caused by a single turn fault. In some cases, the generator may run with a faulted turn until it is repaired and therefore the current pick-up level should be increased to allow operation but still be able to detect a second fault. The P343/P344/P345 IA2/IB2/IC2 current inputs can be used for this type of application and has independent settings per phase (Interturn Is_A, Interturn Is_B, Interturn Is_C). Therefore, the current setting can be increased on the faulted phase only without affecting the sensitivity of the protection on the other unfaulted phases. A time delay is used to prevent operation on CT transient error currents that may occur during external faults. The problem of CT transient error currents can be eliminated by using core balance (window) type CTs (see the *Generator interturn protection using core balance (window) CTs* diagram).

This method of interturn protection will detect phase and some ground faults in the stator winding. However, because of the slow operating time of this protection it is common practice to provide standard high speed differential protection for each phase and separate earth fault protection. If there are main 1 and main 2 P343/P344/P345 protection relays, the IA2/IB2/IC2 inputs could be used for interturn protection on the one relay and used for standard differential protection across the generator in the other relay.

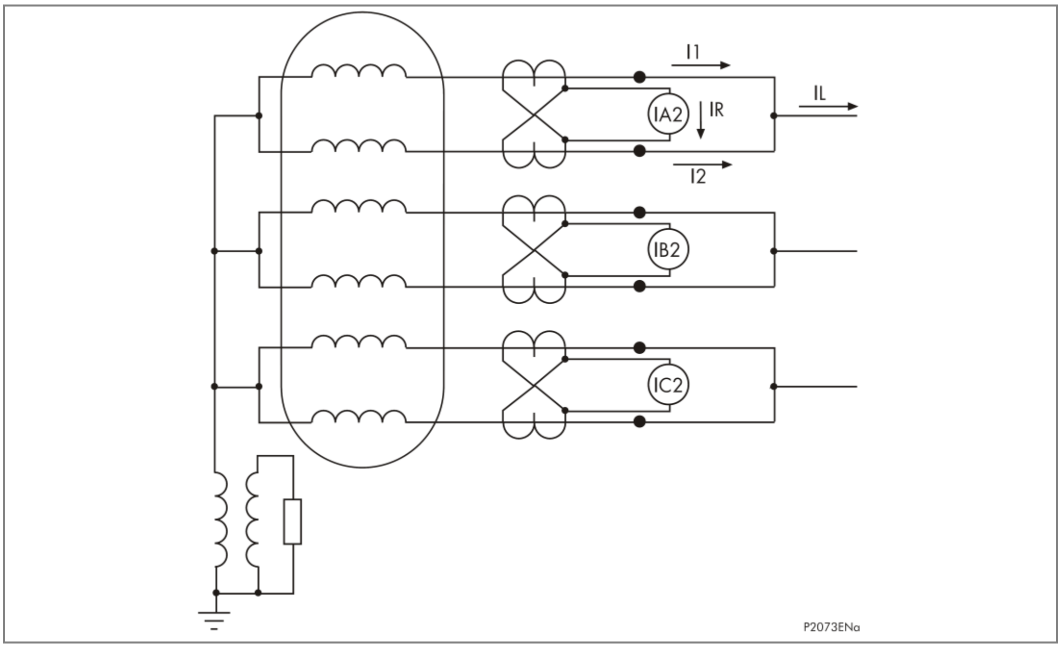


Figure 9 - Generator interturn protection using separate CTs

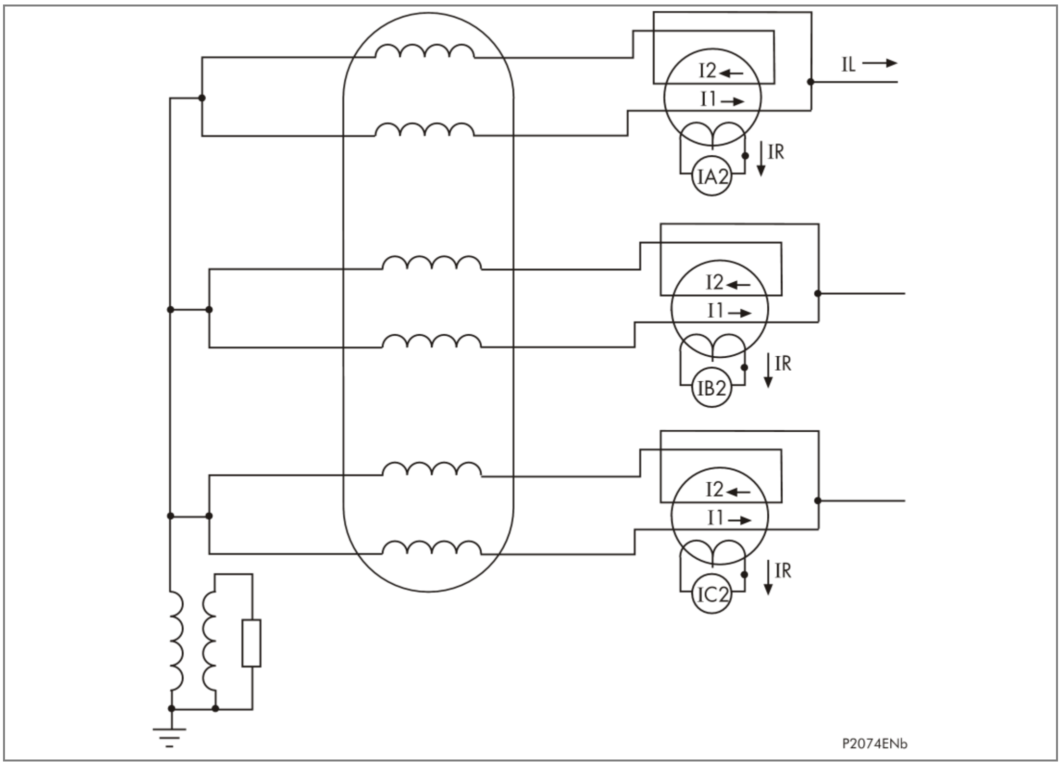


Figure 10 - Generator interturn protection using core balance (window) CTs

2.2.3.1.1 <u>Setting Guidelines for Generator Differential Interturn Protection</u>

The differential setting, Configuration - Differential, should be set to Enabled. If the winding type in the SYSTEM CONFIG - Winding Config is set to Generator, then the settings related to Generator differential protection will be displayed in the column DIFFERENTIAL - Generator Diff.

To select interturn differential protection the Gen Diff Func cell should be set to Interturn.

The differential current settings, Interturn Is_A, Interturn Is_B, Interturn Is_C, should be set to a low setting to protect as much of the machine winding as possible. A setting of 5% of rated current of the machine is generally considered to be adequate. This setting may need to be increased where low accuracy class CTs are used to supply the protection.

The time delay setting Interturn Delay should be set to prevent operation on CT transient error currents that may occur during external faults. A typical time setting would be 0.1 s.

2.2.3.2 Application of Biased Generator Differential Protection for Interturn Protection

For inter-turn protection applications where the generator stator is wound with 2 or more identical three-phase windings connected in parallel, provided the windings are brought out separately, biased differential protection can be used connected to CTs in the line ends of the 2 or more windings, see the *Transverse biased differential protection for double wound machines* diagram. In this type of application a biased system should always be used as it is not possible to guarantee in advance that exact current sharing between the windings will take place. A small error in this sharing current would produce instability in an unbiased system at high levels of through fault current. Balanced current in the two windings produces a circulation of current in the current transformer secondary circuit, but any in zone fault, including an interturn fault, will result in a circulation of current between the windings producing an output in the relay operating circuit.

The biased differential protection in the P343/P344/P345 uses both sets of three-phase current inputs and so if the P343/P344/P345 generator differential protection was used for inter-turn protection no other protection function in the P343/P344/P345 would be available. As normally differential protection plus the many other protection functions in the P343/P344/P345 are required for the generator protection in addition to the interturn protection it is advisable to use a separate biased differential relay for the interturn protection in this application.

Another scheme that could be used on this type of generator is shown in the *Generator differential and interturn protection* diagram. This arrangement is an attempt to get the benefits of inter-turn and differential protection with a saving in CTs and relays. However, this arrangement is not as sensitive as other schemes using separate inter-turn relays or differential relays. The scheme in the *Generator differential and interturn protection* diagram requires the neutral end CTs having half the turns ratio of the terminal end CTs. The sensitivity of the protection for inter-turn faults is limited by the fact that the two CT ratios applied must be selected in accordance with the generator rated current.

A P343/P344/P345 could be used for this application with the IA/IB/IC inputs connected to the terminal side CTs as these see the full rated current. Note, the IA/IB/IC inputs feed the current, impedance and power based protection. However, in the case of a single generator feeding an isolated system, back-up protection should use CTs at the neutral end of the machine to ensure internal faults on the generator windings are detected. Therefore for this type of application it is advised that a separate biased differential protection is used for the inter-turn protection. A P342 from separate CTs at the neutral end of the generator could then be used for the rest of the protection.

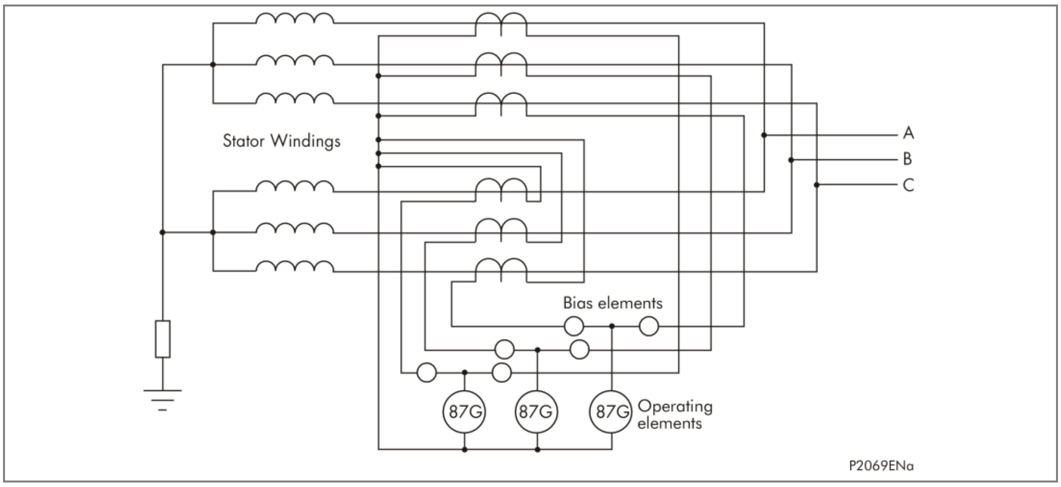


Figure 11 - Transverse biased differential protection for double wound machines

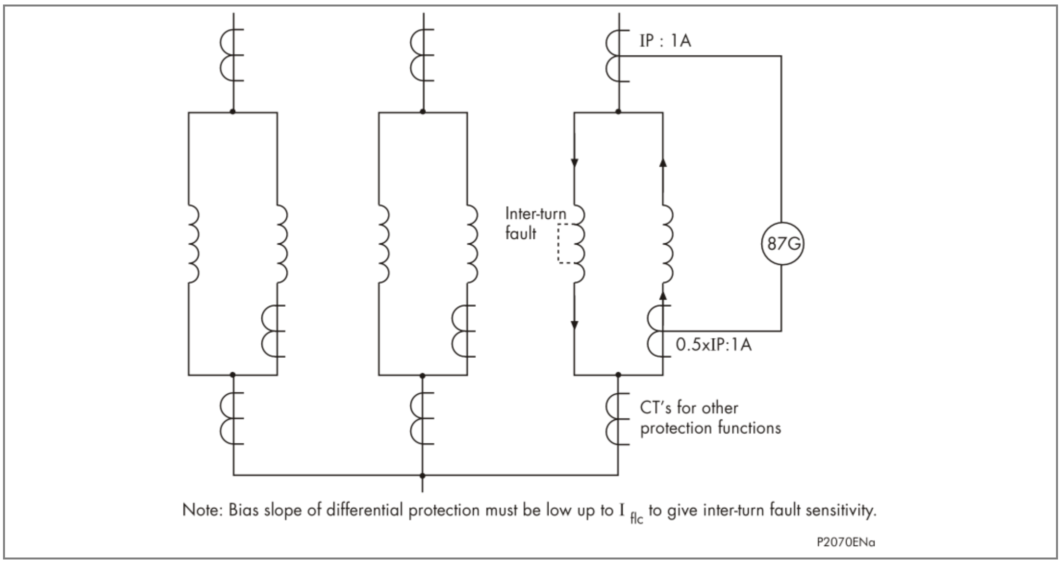


Figure 12 - Generator differential and interturn protection

2.2.3.3 Application of Overcurrent Protection for Interturn Protection

Another method that could be used for inter-turn protection is to use the current operated stator earth fault protection function using an additional single CT as shown in the following diagram.

In this application the neutral voltage displacement protection (59N) would act as the main stator earth fault protection even though the current based stator earth fault protection could still respond to some stator earth fault conditions. This form of interturn fault protection, using the 51N stator earth fault current operated element (IN>1/2 or ISEF>1) offers the possibility of greater sensitivity compared to the technique shown in the previous diagram. This is due to the fact that the required ratio of the single CT for this application is arbitrary. The current setting of the main current operated element (IN>1/2 or ISEF>1) should be set in accordance with the selected CT ratio to provide adequate primary sensitivity for the minimum interturn fault current. For similar reasons the time delay applied should be set similar to that recommended for applications of the main current operated element of normal stator earth fault protection.

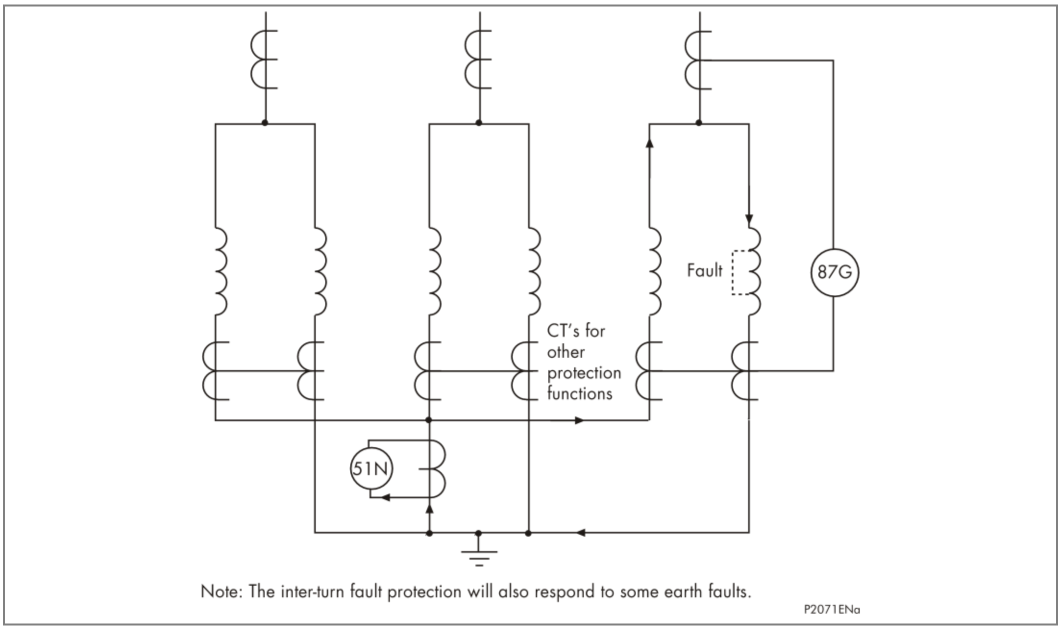


Figure 13 - Overcurrent interturn protection

2.2.3.4 Interturn Protection by Zero Sequence Voltage Measurement

Interturn faults in a generator with a single winding can be detected by observing the zero sequence voltage across the machine. Normally, no zero sequence voltage should exist but a short circuit of one or more turns on one phase will cause the generated emf to contain some zero sequence component. This method of interturn protection can be provided using the neutral voltage displacement protection in the P342/P343/P344/P345, see the *Residual Overvoltage/Neutral Voltage Displacement Protection Function (59N)* section.

External earth faults will also produce a zero sequence voltage on a directly connected generator. Most of the voltage will be dropped across the earthing resistor, the drop on the generator being small and the zero sequence component being limited to one or two percent. It is preferable, therefore, to measure the voltage drop across the winding, rather than the zero sequence voltage to earth at the line terminals. This can be done using a voltage transformer connected to the line side of the generator, with the neutral point of the primary winding connected to the generator neutral, above the earthing resistor or earthing transformer. This arrangement is shown in the following diagram.

The zero sequence voltage can be measured directly from the voltage transformer broken delta winding connected to the neutral voltage input, VN1 (VN>3/4), on the P342/P343 and VN1 (VN>3/4) or VN2 (VN>5/6) on the P344/P345. Alternatively, the zero sequence voltage can be derived (VN>1/2) from the three-phase voltage inputs, VA, VB, VC, to the relay.

The 3rd harmonic component of the emf may be larger than the required setting, however, there is no danger of maloperation as the 3rd harmonic component is filtered by the relay's Fourier filter.

With a direct-connected machine it is still possible that a close up earth fault will produce a zero sequence voltage drop greater than that produced by the short circuiting of one turn. It is therefore necessary to apply a short time delay to the tripping element. With a generator-transformer unit an external earth fault can not draw zero sequence current through the delta winding of the transformer. Therefore, no residual voltage will be produced from the voltage transformer and so no time delay is required in this case for the trip element.

With this type of VT connection the zero sequence voltage from the VT is small for an external fault. Also, the output from the star connected secondary winding of the VT will not be able to correctly represent phase-ground voltages (for external faults), only phase-phase voltages will remain accurate. Therefore, the sensitive directional earth fault protection and CT supervision element, which use zero sequence voltage, may not operate if the VN polarizing input is set to Derived. The VN polarizing input should be set to Measured or the function disabled for these functions where the Main VT is used for interturn protection (Measured is the VN1 input for P342/P343/P344/P345). The under and over voltage protection can be set as phase to phase measurement with this type of VT connection. The underimpedance and the voltage dependent overcurrent use phase-phase voltages anyway, therefore the accuracy should not be affected. The protection functions which use phase-neutral voltages are the power, the loss of excitation and pole slipping protection; all are for detecting abnormal generator operation under three-phase balanced conditions, therefore the accuracy of these protection functions should not be affected.

If the neutral voltage displacement element is required for 95% stator earth fault protection as well as interturn protection a separate VT connection at the terminals of the generator or a distribution transformer at the generator earth is required to obtain the correct zero sequence voltage. The neutral voltage displacement protection in the P342/P343 relay can use the measured residual voltage from the VN1 input and the derived residual voltage from the three-phase voltage inputs. So, if the derived residual voltage is used for interturn protection, then the measured residual voltage from a distribution transformer at the generator neutral point can not be used for 95% stator earth fault protection using one relay. The P344/P345 has two dedicated neutral voltage displacement inputs, VN1 and VN2, as well as a derived neutral voltage element. So one neutral voltage input can be used for interturn protection and one for 95% stator earth fault protection, see the following diagram. See the *Residual Overvoltage/Neutral Voltage Displacement Protection Function (59N)* section for more information on the P342/P343/P344/P345 neutral voltage displacement protection.

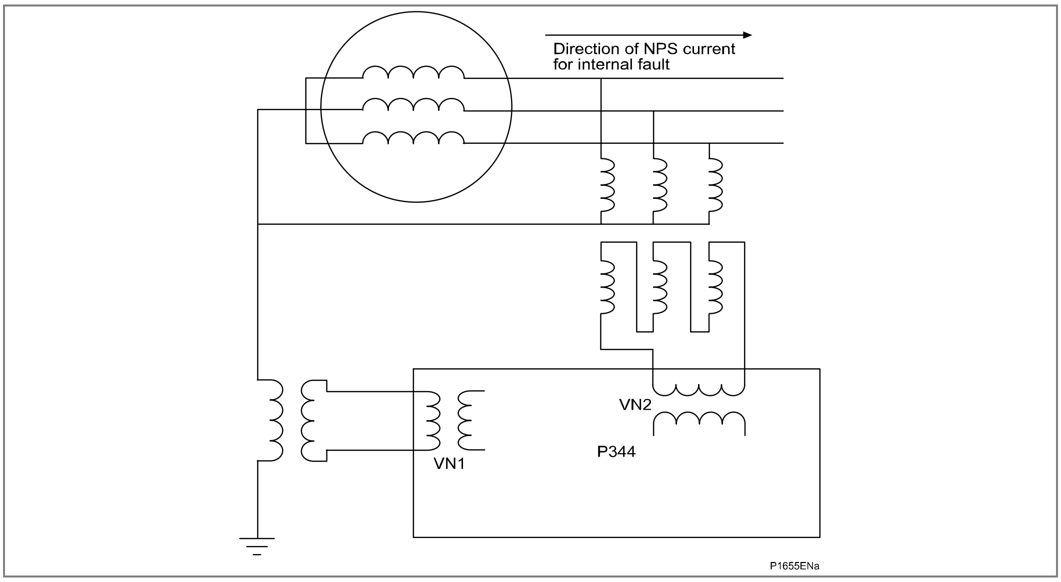


Figure 14 - Interturn protection (VN2) and earth fault protection (VN1) by zero sequence voltage measurement

2.2.3.4.1 <u>NPS Overpower and NPS Overcurrent Interlocking for Zero Sequence Voltage Interturn Protection</u>

To prevent the neutral voltage (zero sequence) element used for interturn protection from maloperation for an external phase-phase or earth fault, the element can be interlocked with a NPS apparent power element (S2 = I2 x V2, non-directional) and a directional NPS overcurrent element looking away from the machine. The trip signal is issued only if all of the elements, VNx>, S2> and I2> operate. An example of the PSL logic for this interlocking is shown in the following diagram.

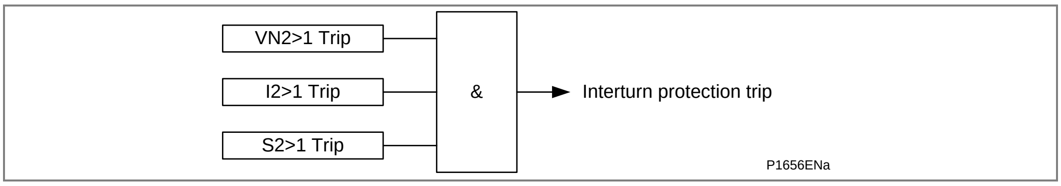


Figure 15 - Interturn protection interlocking PSL logic

See these sections for more information on the NPS Overpower and directional NPS overcurrent protection.

- NPS Overpower (32NP)
- Negative Phase Sequence (NPS) Overcurrent Protection (46OC)

The following two diagrams show the negative phase sequence fault current direction during an internal fault and external fault for a generator application. These diagrams show the direction of negative phase sequence current at the neutral point is always the same for internal and external faults. The direction of the negative phase sequence current is different for internal and faults from the terminal side CTs.

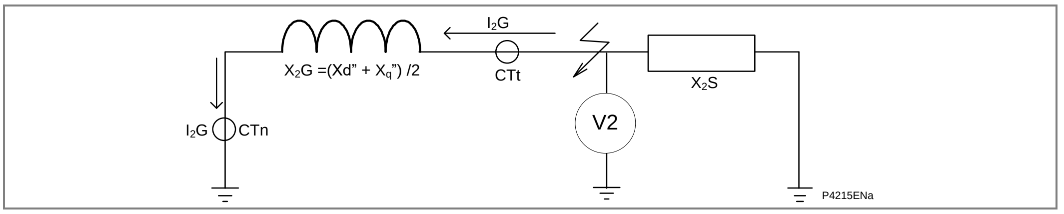


Figure 16 - Negative sequence diagram for external fault

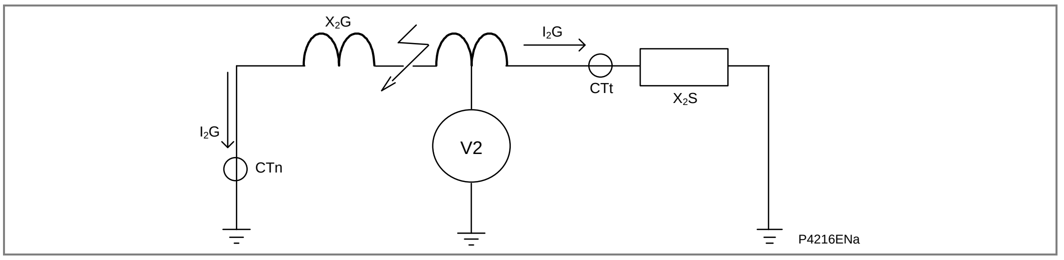


Figure 17 - Negative sequence diagram for internal fault

2.3 Generator-Transformer Differential Protection (87GT)

In applying the well established principles of differential protection to a generator-transformer unit, a variety of considerations have to be taken into account. These include compensation for any phase shift across the transformer, possible unbalance of signals from current transformers either side of windings and the effects of the variety of earthing and winding arrangements. In addition to these factors, which can be compensated for by correct application of the relay, the effects of normal system conditions on relay operation must also be considered. The differential element must be blocked for system conditions which could result in maloperation of the relay, such as high levels of magnetizing current during inrush conditions or during transient overfluxing.

In traditional transformer differential schemes, the requirements for phase and ratio correction were met by the application of external interposing current transformers, as a secondary replica of the main transformer winding arrangements, or by a delta connection of main CTs (phase correction only). The P343/P344/P345 has settings to allow flexible application of the protection to a wide variety of transformer configurations, or to other devices where differential protection is required, without the need for external interposing CTs or delta connection of secondary circuits.

2.3.1 Biased Elements

The relay percentage bias calculation is performed 4 times per cycle. A triple slope percentage bias characteristic is implemented. Both the flat and the lower slope provide sensitivity for internal faults. Under normal operation steady state magnetizing current and the use of tap changers result in unbalanced conditions and hence differential current. To accommodate these conditions, the initial slope, K1, may be set to 30%. This ensures sensitivity to faults while allowing for mismatch when the power transformer is at the limit of its tap range and CT ratio errors. At currents above rated, extra errors may be gradually introduced as a result of CT saturation, so the higher slope may be set to 80% to provide stability under through fault conditions, during which there may be transient differential currents due to saturation effect of the CTs. The through fault current in all but ring bus or mesh fed transformers is given by the inverse of the per unit reactance of the transformer. For most transformers, the reactance varies between 0.05 to 0.2 pu, therefore typical through fault current is given by 5 to 20 In.
The number of biased differential inputs required for an application depends on the transformer and its primary connections. It is recommended that, where possible, a set of biased CT inputs is used for each set of current transformers. According to IEEE Std. C37.110-2007 separate current inputs should be used for each power source to the transformer. If the secondary windings of the current transformers from two or more supply breakers are connected in parallel, under heavy through fault conditions, differential current resulting from the different magnetizing characteristics of the current transformers will flow in the relay. This current will only flow through one current input in the relay and can cause misoperation. If each CT is connected to a separate current input, the total fault current in each breaker provides restraint. It is only advisable to connect CT secondary windings in parallel when both circuits are outgoing loads. In this condition, the maximum through fault level will then be restricted solely by the power transformer impedance. The P343/P344/P345 relays only have 2 biased differential inputs so can only be used to protect 2 winding generator-transformer configurations. The typical connection for this relay is shown in this diagram.

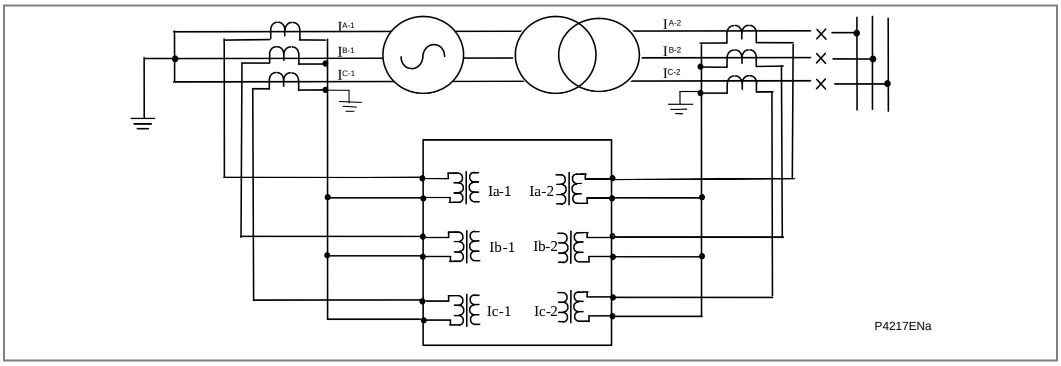


Figure 18 - P34x & P391 typical connection for generator-transformer unit connection

The relay achieves stability for through faults in two ways, both of which are essential for correct relay operation. The first consideration is the correct sizing of the current transformers; the second is by providing a relay bias characteristic as shown in this diagram:

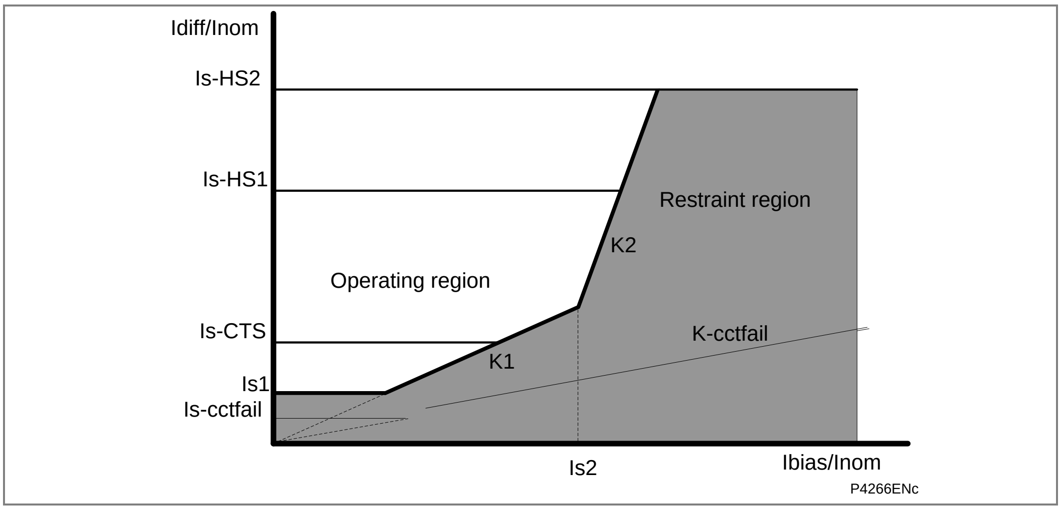


Figure 19 - Relay triple slope (flat, K1, K2) biased differential protection

The flat and lower slope, K1, provides sensitivity for internal faults. The higher slope, K2, provides stability under through fault conditions, during which there may be transient differential currents due to asymmetric CT saturation.

The differential and biased current calculations are done on a per phase basis after amplitude, vector group matching and zero sequence filtering are performed. The following equations are valid for uniformly defined current arrows relative to the protected equipment, so the current arrows of all windings point either towards the protected object or away from it.

The differential current, I_{diff}, and the bias current I_{bias} are defined by the following expressions:

$$I_{diff} = \left| \underline{I_1} + \underline{I_2} \right|$$

$$I_{diff} = \frac{\left|\underline{I_1}\right| + \left|\underline{I_2}\right|}{2}$$

The differential current, I_{diff}, is the vector sum of the phase currents measured at the two ends of the generator-transformer. The mean bias current, I_{bias} is the scalar mean of the magnitude of the currents at the two ends of the generator-transformer.

To provide stability for external faults the following measures are taken on the bias calculations:

- Delayed bias: the bias quantity is the maximum of the bias quantities calculated within the last cycle. This is to maintain the bias level, providing stability during the time when an external fault is cleared. This featured is implemented on a per phase basis
- Transient bias: an additional bias quantity is introduced into the bias calculation, on a per phase basis, if there is a sudden increase in the mean-bias measurement. This quantity will decay exponentially afterwards. The transient bias is reset to zero once the relay has tripped or if the mean-bias quantity is below the Is1 setting. The transient bias algorithm is executed 4 times per cycle.
- Maximum bias: the bias quantity used per phase for the percentage bias characteristic is the maximum delayed bias current calculated from all three phases.

$$Ibias_{max} = \text{Maximum}\left[Ia_{bias}, Ib_{bias}, Ic_{bias}\right]$$

For these relays the restraining effect (bias current) never disappears when there is an internal fault; the restraining effect is even reinforced. However, the restraining current factor ½ means that the differential current Id has twice the value of the restraining current I_{bias}, so that safe and reliable tripping is also guaranteed in the case of multi-end infeed for internal faults.

As shown in the *Relay triple slope (flat, K1, K2) biased differential protection* diagram, the tripping characteristic of the differential protection has two knees. The first knee is dependent on the setting of the basic threshold value Is1. The second knee of the tripping characteristic is defined by the setting Is2.

The basic pick up level of the low set differential element, Is1, is dependant on the item of plant being protected and by the amount of differential current that might be seen during normal operating conditions. A setting of 0.2 pu is generally recommended when the relay is used to protect a generator-transformer unit.

The flat section of the tripping curve represents the most sensitive region of the tripping characteristic in the form of the settable basic threshold value Is1. The default setting of 0.2 pu takes into account the steady state magnetizing current of the transformer, which flows even in a no-load condition and is generally less than 5% of the nominal transformer current.

Characteristic equation:

$$Ibias < \frac{Is1}{K1}$$

$$Idiff >= Is1$$

The flat and K1 slopes of the tripping curve cover the load current range, so that in these sections we must account for not only the transformer steady state magnetizing current, which appears as differential current, but also with differential currents that can be attributed to the transformation errors of the current transformer sets and on load tap changers.

If we calculate the worst case with IEC class 10P current transformers, the maximum allowable amplitude error according to IEC 60044-1 is 3 % for nominal current. The phase-angle error can be assumed to be 2° for nominal current. The maximum allowable total error for nominal current is then obtained, in approximation, as $(0.03 + \sin 2°) \approx 6.5$ %. If the current is increased to the nominal accuracy limit current, the total error for Class 10P current transformers can be 10 % maximum, as may be the case under heavy fault conditions. Beyond the nominal accuracy limit current, the transformation error can be of any magnitude.

The dependence of the total error of a current transformer on current is therefore non-linear. In the operating current range (the current range below the nominal accuracy limit current) we can expect a worst case total error of approximately 10 % per current transformer set.

The first slope section of the tripping characteristic forms a straight line, the slope of which should correspond to the cumulative total error of the participating current transformer sets and on load tap changer. The curve slope, K1, can be set. The default setting for K1 is 30%.

Characteristic equation:

Idiff > Is1

and

Ibias < Is2

Idiff >= K1 x Ibias

The second knee point, Is2, is settable. It has a default setting of 1 pu and must be set in accordance with the maximum possible operating current.

Restraining currents that go beyond the set knee point (Is2) are typically considered as through fault currents. For through fault currents, the third section of the tripping characteristic could therefore be given an infinitely large slope. Since, however, we also need to take into account the possibility that a fault can occur in the transformer differential protected zone, a finite slope K2 is provided for the third section of the tripping curve. The default setting for K2 is 80%.

Characteristic equation:

Idiff >= Is2

Idiff >= K1 x Is2 + K2 (Ibias – Is2)

Note	*The default settings for Xform Is2 (1pu), Xform K1 (30%) and Xform K2 (80%) should always be used as the CT requirements are based on these settings.*

2.3.2 Ratio Correction

To ensure correct operation of the differential element, it is important that under load and through fault conditions the currents into the differential element of the relay balance. In many cases, the HV and LV current transformer primary ratings will not exactly match the transformer winding rated currents. Ratio correction factors are therefore provided. The CT ratio correction factors are applied to ensure that the signals to the differential algorithm are correct.

A reference power, identical for both HV/LV windings, is defined in the Sref setting cell under the SYSTEM CONFIG menu heading. The ratio correction factor for each winding of the generator-transformer is calculated by the relay on the basis of the set reference power, the set primary nominal voltages of the transformer and the set primary nominal currents of the current transformers.

$$K_{amp,n} = \frac{I_{primCT,nom,n}}{\dfrac{S_{prim,ref}}{\sqrt{3V_{primCT,nom,n}}}}$$

Where:

$K_{amp,n}$ = amplitude matching factor for the respective CT input

$I_{primCT,nom,n}$: primary nominal current for the respective CT input

$V_{primCT,nom,n}$: nominal voltage for the respective CT input. Where on-load tap changing is used, the nominal voltage chosen should be that for the mid tap position.

$S_{prim,ref}$: common primary reference value of S for all windings

Therefore, the only data needed for ratio correction or amplitude matching calculations done by the relay are the nominal values read from the generator/transformer nameplate.

For the generator-transformer shown in the "Ratio Correction or Amplitude Matching Factor" diagram, the phase C amplitude matched currents of the HV and LV windings are the same.

$I_{amp,HV,C} = K_{amp,HV} \times I_{HV,C}$

$I_{amp,LV,C} = K_{amp,LV} \times I_{LV,C}$

Where:

$I_{amp,\ HV,C}$; HV side phase C amplitude matched current

$K_{amp,HV}$: HV side calculated ratio correction factor

$I_{HV,C}$: HV side phase C current magnitude

$I_{amp,\ LV,C}$; LV side phase C amplitude matched current

$K_{amp,LV}$: LV side calculated ratio correction factor

$I_{LV,C}$: LV side phase C current magnitude

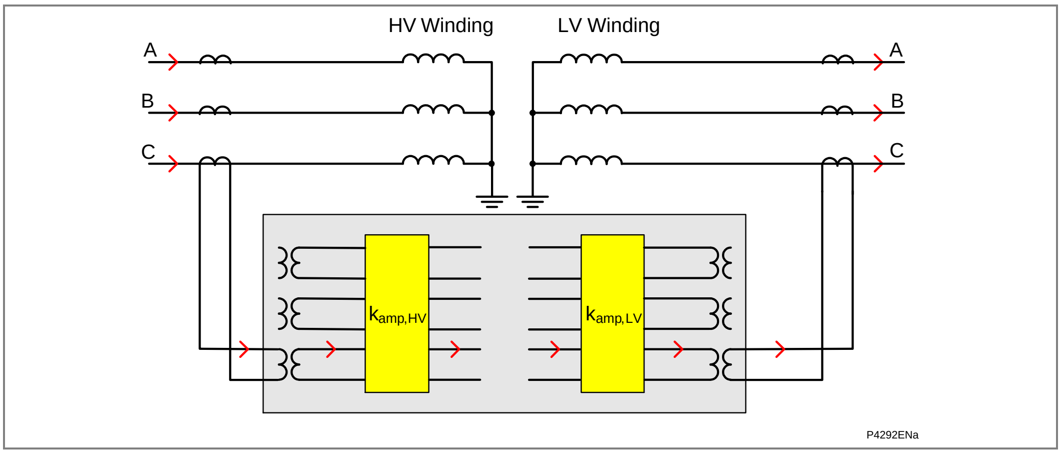


Figure 20 - Ratio correction or amplitude matching factor

Matching factors are displayed by the relay in the **Match Factor HV** and **Match Factor LV** data cells under the **SYSTEM CONFIG** menu heading. The relay derives amplitude matching factors automatically so that all biased currents are compared on a like for like basis. The range of the calculated matching factors is from 0.05 to 20. Amplitude matching factors above 20 are not recommended since the probability of tripping due to electrical noise is very high.

2.3.3 Vector Group Correction

To compensate for any phase shift between two windings of a generator-transformer it is necessary to provide vector group correction. This was traditionally provided by the appropriate connection of physical interposing current transformers, as a replica of the main transformer winding arrangements, or by a delta connection of the main CTs.

This matching operation can be carried out regardless of the phase winding connections, since the phase relationship is described unambiguously by the characteristic vector group number.

Vector group matching is therefore performed by mathematical phasor operations on the amplitude-matched phase currents of the low-voltage side in accordance with the characteristic vector group number. The vector group is the clock-face hour position of the LV A-phase voltage, with respect to the A-phase HV voltage at 12-o'clock (zero) reference. Phase correction is provided in the P34x using SYSTEM CONFIG then LV Vector Group for phase shift between HV and LV windings.

This is shown in the following figure for vector group characteristic number 5, where vector group Yd5 is used as the example:

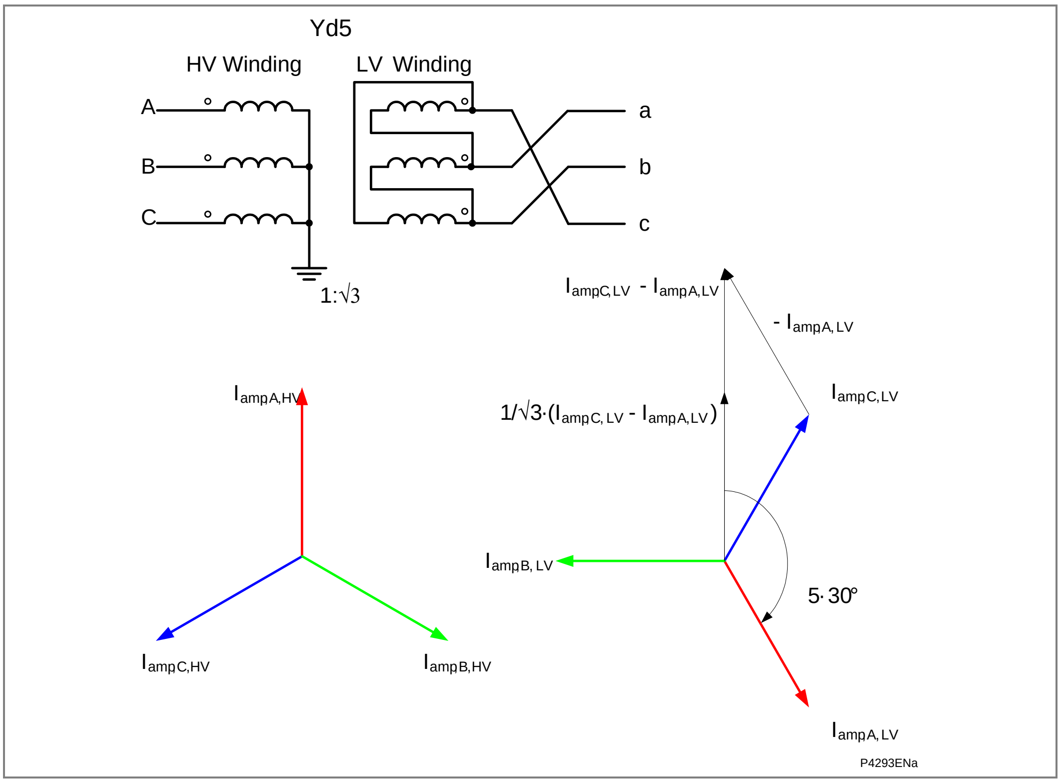


Figure 21 - Yd5 transformer example

The angle of positive sequence primary current is used as a default; therefore, no vector correction is applied to the high voltage side.

As shown in the above *Yd5 transformer example* diagram, the positive sequence current at the low voltage end is shifted by 150° clockwise for ABC (anti-clockwise) rotation. Therefore the relay setting, **LV Vector Group**, equal to "5" will rotate back the current at the low side for 150° in an anti-clockwise direction. This assures that the primary and secondary currents are in phase for load and external fault conditions. The vector correction also considers amplitude matching. If the vector group is any odd number, the calculated current will be greater by √3; therefore; this current will be automatically divided by √3. Hence, this effect does not need to be taken into account when CT correction compensation is automatically calculated or set.

Setting the vector group matching function is very simple and does not require any calculations. Only the characteristic vector group number needs to be set in **LV Vector Group**.

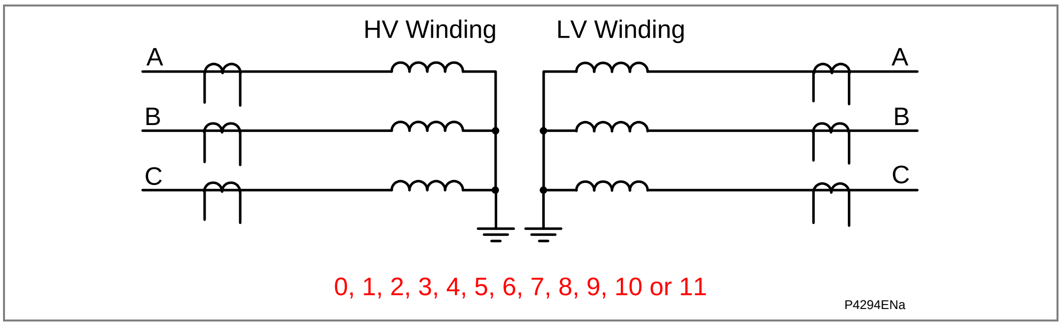


Figure 22 - Vector group selection

Other nameplate designations may be used instead of the clock notation. Common examples are:

Alternatives		Equivalent standard	LV group setting
D_{AB}/Y	D_{AB} – Y	Dy1	1
D_{AC}/Y	D_{AC} – Y	Dy11	11
Y/Y	Y_0 - Y0	Yy0	0
Y/Y	Y_0 - Y6	Yy6	6

Table 3 - Vector group designations

2.3.4 Zero Sequence Filter

In addition to mimicking the phase shift of the protected transformer, it is also necessary to mimic the distribution of primary zero sequence current in the protection scheme. The necessary filtering of zero sequence current has also been traditionally provided by appropriate connection of interposing CTs or by delta connection of main CT secondary windings. In the relay, the user does not need to decide which windings need zero sequence filtering. The user just needs to set which windings are grounded using a Yn, Zn or in zone-earthing transformer. The relay will adjust itself accordingly. In the advanced setting mode, it is possible to override the self adaptive setting with the zero sequence filtering enabled/disabled setting.

Where a transformer winding can pass zero sequence current to an external earth fault, it is essential that some form of zero sequence current filtering is used. This ensures that out of zone earth faults will not cause the relay to maloperate.

An external earth fault on the star side of a Dyn11 transformer will result in zero sequence current flowing in the current transformers associated with the star winding. However, due to the effect of the delta winding, there will be no corresponding zero sequence current in the current transformers associated with the delta winding.

To ensure stability of the protection, the LV zero sequence current must be eliminated from the differential current. Traditionally this has been achieved by either delta connected line CTs or by the inclusion of a delta winding in the connection of an interposing current transformer.

In accordance with its definition, the zero-sequence current is determined as follows from vector and amplitude matched phase currents:

$$\vec{I}_0 = \frac{1}{3} \cdot \left(\vec{I}_{A,vector\_comp} + \vec{I}_{B,vector\_comp} + \vec{I}_{C,vector\_comp} \right)$$

The current that is used in the differential equation is the filtered current per phase:

$$\vec{I}_{A,filtered} = \vec{I}_{A,vector\_comp} - \vec{I}_0$$

$$\vec{I}_{B,filtered} = \vec{I}_{B,vector\_comp} - \vec{I}_0$$

$$\vec{I}_{C,filtered} = \vec{I}_{C,vector\_comp} - \vec{I}_0$$

Setting the zero-sequence current filtering function is very simple and does not require any calculations. Zero-sequence current filtering should only be activated for those ends where there is operational earthing (grounding) of a neutral point:

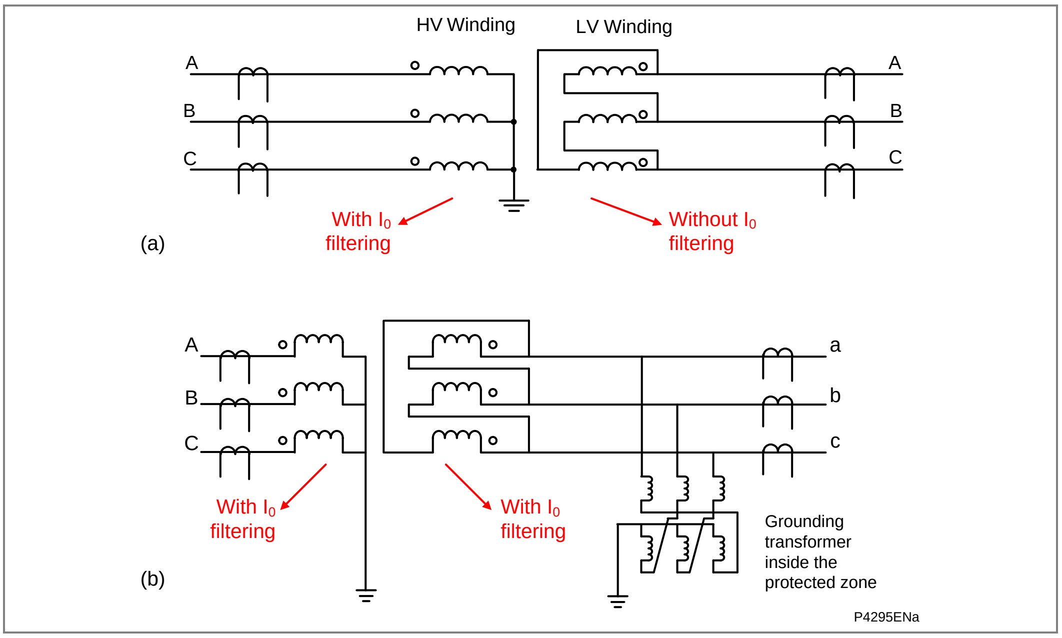


Figure 23 - Zero sequence current filtering

The following figure shows the current distribution for an AN fault on the delta side of a Yd1 transformer with a grounding transformer inside the protected zone.

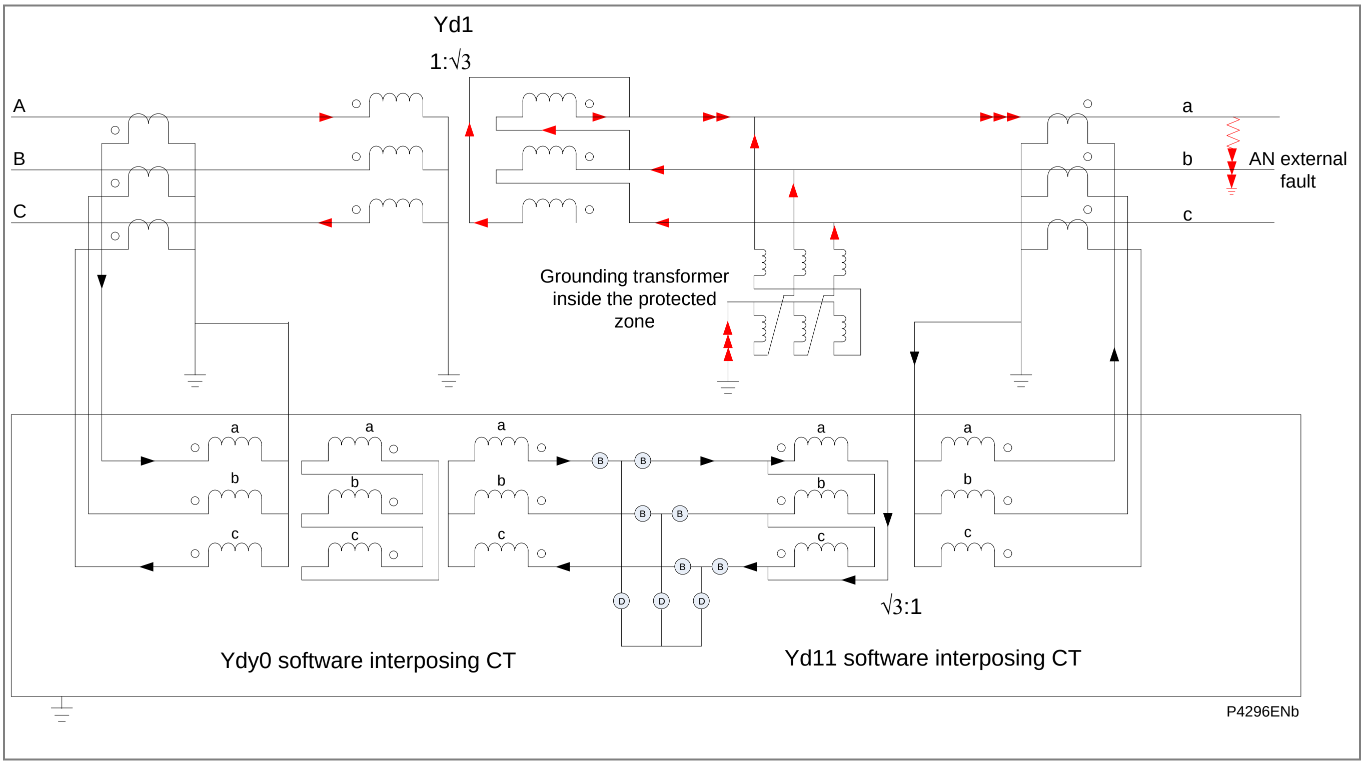


Figure 24 - Current distribution for an external fault on the delta side of a Yd1 transformer

2.3.5 Magnetizing Inrush Stabilization

When a transformer is first energized, a transient magnetizing current flows, which may reach instantaneous peaks of 8 to 30 times the full load current. The factors controlling the duration and magnitude of the magnetizing inrush are:

- Size of the transformer bank
- Size of the power system
- Resistance in the power system from the source to the transformer bank
- Residual flux level
- Type of iron used for the core and its saturation level.

There are three conditions which can produce a magnetizing inrush effect:

- First energization
- Voltage recovery following external fault clearance
- Sympathetic inrush due to a parallel transformer being energized.

The following diagram shows under normal steady state conditions the flux in the core changes from maximum negative value to maximum positive value during one half of the voltage cycle, which is a change of 2.0 maximum.

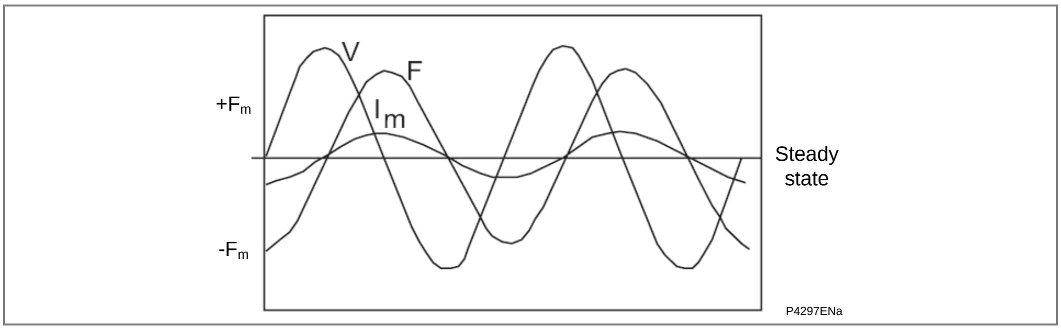


Figure 25 - Steady state magnetizing inrush current

If the transformer is energized at a voltage zero when the flux would normally be at its maximum negative value, the flux will rise to twice its normal value over the first half cycle of voltage. To establish this flux, a high magnetizing inrush current is required. The first peak of this current can be as high as 30 times the transformer rated current. This initial rise could be further increased if there was any residual flux in the core at the moment the transformer was energized.

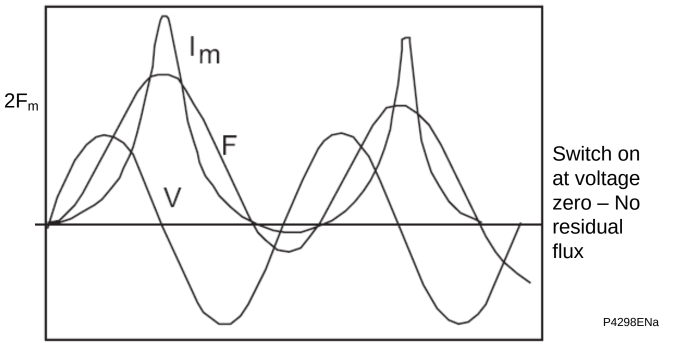


Figure 26 - Magnetizing inrush current during energization

As the flux enters the highly saturated portion of the magnetizing characteristic, the inductance falls and the current rises rapidly. Magnetizing impedance is of the order of 2000% but under heavily saturated conditions this can reduce to around 40%, which is an increase in magnetizing current of 50 times normal. This figure can represent 5 or 6 times normal full load current.

Analysis of a typical magnitude inrush current wave shows (fundamental = 100%):

Component	-DC	2nd H	3rd H	4th H	5th H	6th H	7th H
	55%	63%	26.8%	5.1%	4.1%	3.7%	2.4%

The offset in the wave is only restored to normal by the circuit losses. The time constant of the transient can be quite long, typically 0.1 second for a 100 KVA transformer and up to 1 second for larger units. The initial rate of decay is high due to the low value of air core reactance. When below saturation level, the rate of decay is much slower. The following graph shows the rate of decay of the DC offset in a 50 Hz or 60 Hz system in terms of amplitude reduction factor between successive peaks.

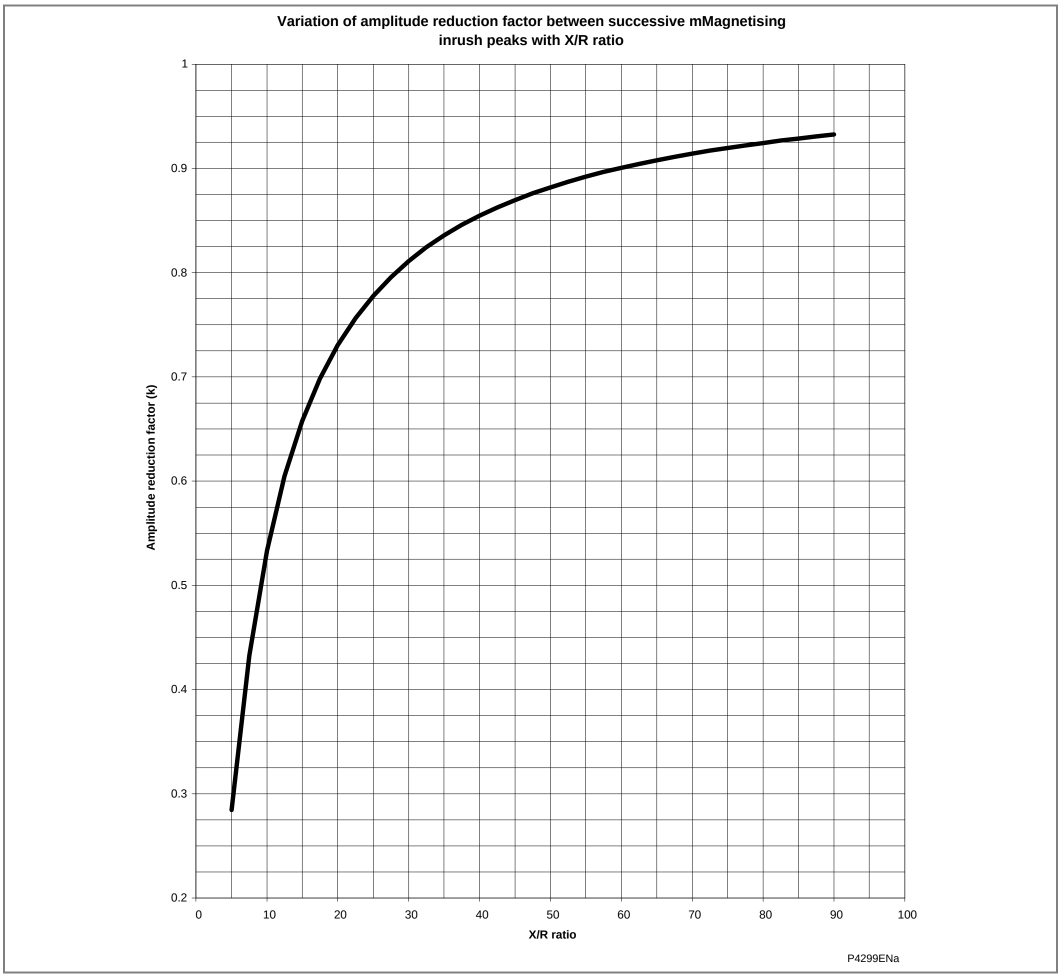


Figure 27 - Variation of amplitude reduction factor

The magnitude of the inrush current is limited by the air core inductance of the windings under extreme saturation conditions. A transformer with concentric windings will draw a higher magnetizing current when energized from the LV side, since this winding is usually on the inside and has a lower air core inductance. Sandwich windings have approximately equal magnitude currents for both LV and HV. Resistance in the source will reduce the magnitude current and increase the rate of decay.

The magnetizing inrush phenomenon is associated with a transformer winding which is being energized where no balancing current is present in the other winding(s). This current appears as a large operating signal for the differential protection. Therefore, special measures are taken with the relay design to ensure that no maloperation occurs during inrush. The fact that the inrush current has a high proportion of harmonics having twice the system frequency offers a possibility of stabilization against tripping by the inrush current.

The second harmonic blocking may not be effective in all applications with all types of transformers. The P64x filters the differential current. The fundamental $I_{diff}(f_0)$ and second harmonic components $I_{diff}(2*f_0)$ of the differential current are determined. If the ratio $I_{diff}(2*f_0)/I_{diff}(f_0)$ exceeds a specific adjustable value (typical setting 20%) in at least one phase, the low-set differential element is blocked optionally in one of these modes:

- Across all three phases if cross blocking is selected
- Selectively for one phase because the harmonic blocking is phase segregated
- There is no blocking if the differential current exceeds the high set thresholds Is-HS1 or Is-HS2.

2.3.6 High Set Operation

The relay incorporates independent transformer differential high set elements, Xform Is-HS1 and Xform Is-HS2 to complement the protection provided by the biased differential low set element, the high set could be disabled and enabled individually. The instantaneous high set offers faster clearance for heavy internal faults and it is not blocked for magnetizing inrush or transient overfluxing conditions.

Stability is provided for heavy external faults, but the operating threshold of the high set differential element must be set to avoid operation with inrush current.

When a transformer is energized, a high magnetizing inrush current is drawn. The magnitude and duration of this inrush current depends on several factors including:

- Size and impedance of the transformer
- Point on wave of switching
- Remnant flux in the transformer
- Number of transformers connected in parallel

It is difficult to accurately predict the maximum anticipated level of inrush current. Typical waveform peak values are of the order of 8 - 30x rated current. A worst-case estimation of inrush could be made by dividing the transformer full load current by the per-unit leakage reactance quoted by the transformer manufacturer. In the simple mode, the relay calculates the setting for Xform Is-HS1 as the reciprocal of the transformer reactance.

A setting range of 2.5 – 16 pu is provided in the P34x relay for Xform Is-HS1 and Xform Is-HS2. Both elements should be set in excess of the anticipated or estimated peak value of inrush current after ratio correction.

The Xform Is-HS2 element uses the fundamental component of the differential current. This element is not restrained by the bias characteristic, so the P34x will trip regardless of the restraining current. Xform Is-HS2 should be set so that the relay will not maloperate during external faults. When through fault current is limited by the transformer impedance, Xform Is-HS2 can be set as $1.3 \times (1/Xt)$. In breaker and a half, ring bus or mesh applications, the through fault current is not limited by the transformer impedance but by the system source impedance. This current can be higher than $1.3 \times (1/Xt)$, therefore the user should consider the actual through fault current when setting Xform Is-HS2. To avoid high values of spurious differential current due to CT saturation during through fault conditions, it is important to equalize the burden on the CT secondary circuits.

2.3.7 Setting Guidelines for Biased Differential Protection

The differential setting, Configuration - Differential, should be set to Enabled. If the winding type in the SYSTEM CONFIG - Winding Config is set to Xformer, then the settings related to Generator-Transformer differential protection will be displayed in the column DIFFERENTIAL - Xformer Diff.

The basic pick up level of the low set differential element, Xform Is1, is variable between 0.1 pu and 2.5 pu in 0.01 pu steps. The setting chosen is dependant on the item of plant being protected and by the amount of differential current that might be seen during normal operating conditions. A default setting of 0.2 pu is generally recommended.

The biased low-set differential protection is blocked under magnetizing inrush conditions and during transient over fluxing conditions if the appropriate settings are enabled. The second harmonic measurement and blocking are phase segregated. If cross blocking is set to enabled, phases A, B and C of the low set differential element are blocked when an inrush condition is detected. The fifth harmonic measurement and blocking are also phase segregated, but no cross blocking is available.

As shown in the following diagram, the first slope is flat and depends on the Xform Is1 setting. It ensures sensitivity to internal faults. The second slope, Xform K1, is user settable. K1 ensures sensitivity to internal faults up to full load current. It allows for the 15% mismatch which can occur at the limit of the transformer's tap-changer range and an additional 5% for any CT ratio errors. The K1 slope should be set above the errors due to CT mismatch, load tap changers and steady state magnetizing current. The errors slope, which is the combined tap changer (T/C) and current transformer (CT) error, should always be below the K1 slope to avoid mal operations. It is recommended to set K1 to 30%, as long as the errors slope is below the K1 slope by a suitable margin. The second slope, Xform K2, is also user settable, and it is used for bias currents above the rated current. To ensure stability under heavy through fault conditions, which could lead to increased differential current due to asymmetric saturation of CTs, K2 is set to 80%.

Note	*The default settings for Xform Is2 (1pu), Xform K1 (30%) and Xform K2 (80%) should always be used as the CT requirements are based on these settings.*

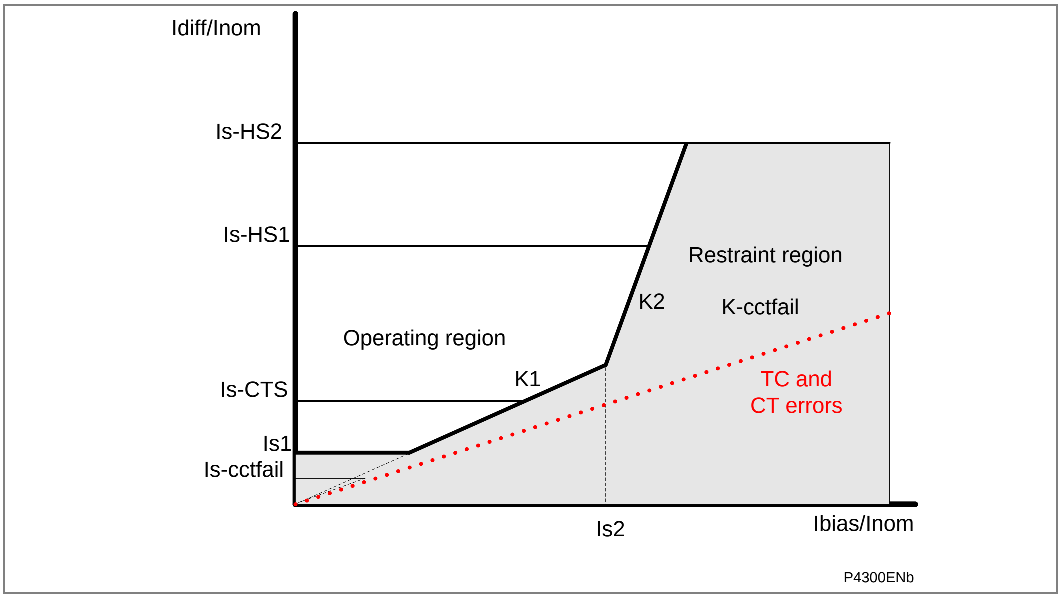


Figure 28 - Tap changer and CT combined errors

Example 1: Two winding transformer for P34x – no tap changer

The following diagram shows the application of P34x to protect a two winding transformer. The power transformer data is: 90 MVA Transformer, Ynd9, 132/33 kV. The current transformer ratios are as follows: HV CT ratio - 400/1, LV CT ratio - 2000/1.

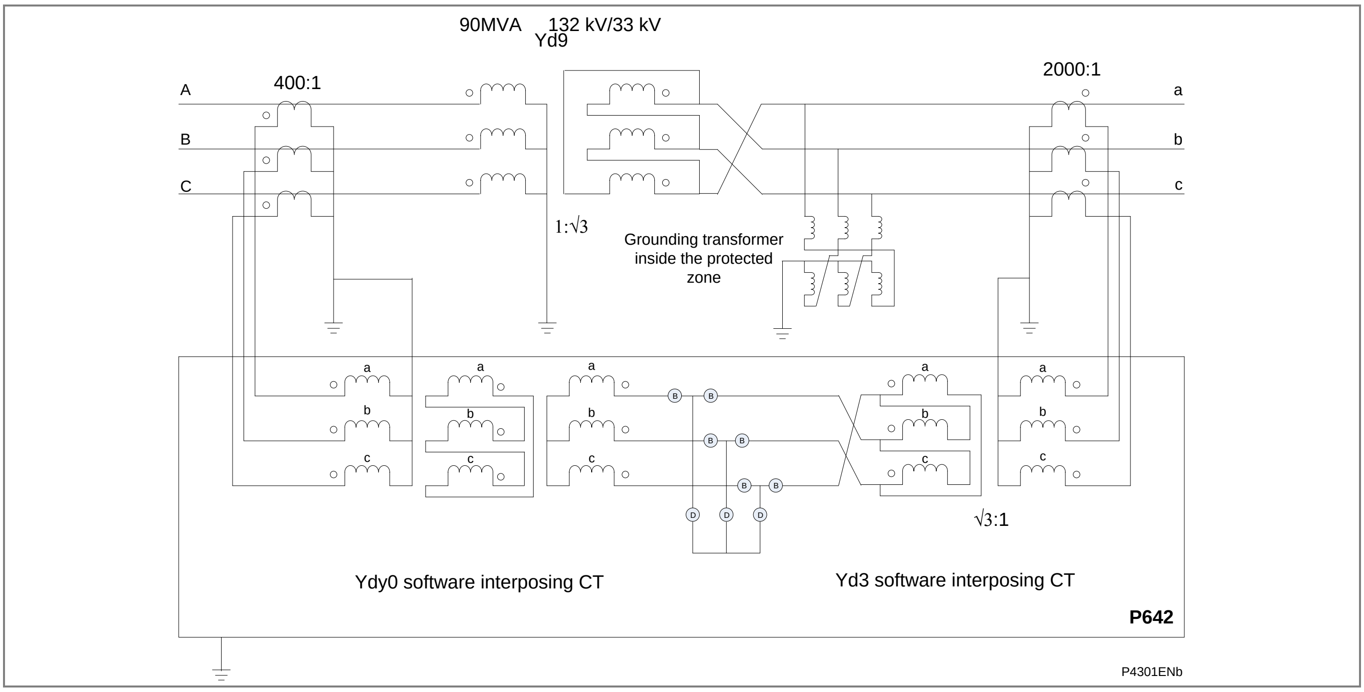


Figure 29 - P34x & P391 used to protect a Generator-Transformer unit

The relay always calculates and sets the amplitude matching factors. As explained previously no vector correction is applied to the high voltage side. Vector correction is done by setting SYSTEM CONFIG then LV Vector Group to 9. The zero sequence filtering is done by setting SYSTEM CONFIG then HV Grounding to Grounded and SYSTEM CONFIG then LV Grounding to Grounded. The following screenshot shows the SYSTEM CONFIG settings for the relay.

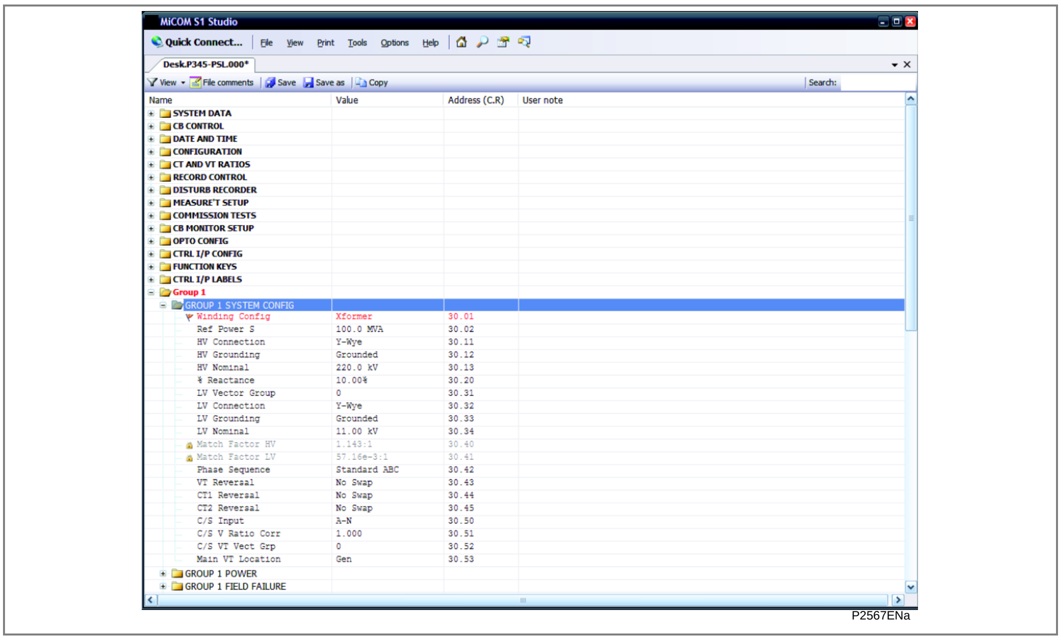


Figure 30 - P34x & P391 SYSTEM CONFIG settings

The ratio correction factors are calculated by the relay as follows:

$$K_{amp,HV} = \frac{I_{nom,HV}}{\dfrac{S_{ref}}{\sqrt{3}V_{nom,HV}}} = \frac{400}{\dfrac{90 \times 10^6}{\sqrt{3} \times 132 \times 10^3}} = 1.016$$

$$K_{amp,LV} = \frac{I_{nom,LV}}{\frac{S_{ref}}{\sqrt{3}V_{nom,LV}}} = \frac{2000}{\frac{90 \times 10^6}{\sqrt{3} \times 33 \times 10^3}} = 1.270$$

Where:

S_{ref}: common reference power for all ends

K_{am}, HV, LV: ratio correction factor of HV or LV windings

I_{nom}, HV, LV: primary nominal currents of the main current transformers

V_{nom}, HV,LV: primary nominal voltage of HV or LV windings

The recommended settings for the differential function (Xform Is1, Xform Is2, Xform K1, Xform K2, second and fifth harmonic blocking) were discussed in previous sections, and they are as follows:

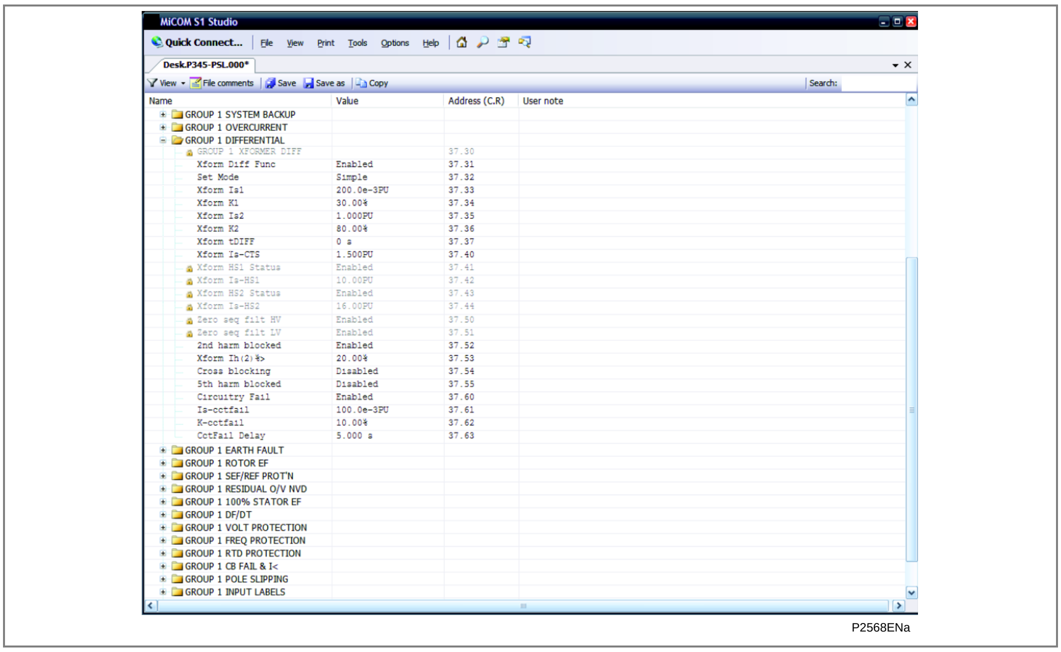


Figure 31 - P34x & P391 Xformer DIFF PROTECTION settings

2.4 NPS Overpower (32NP)

For the interturn interlocking logic a single stage negative phase sequence apparent overpower element S2>1 is provided. The 3 phase current source can be selected using the S2> CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting. In the standard connection diagrams in the Connection Diagrams chapter, IA-1/IB-1/IC-1 is connected to the neutral side CTs and IA-2/IB-2/IC-2 is connected to the terminal side CTs.

2.4.1 Setting Guidelines for NPS Overpower

The power pick-up threshold must be set higher than the negative phase sequence apparent power 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 negative phase sequence apparent power, and setting at least 20% above this figure.

This element is applied primarily to provide an interlocking signal for interturn protection. Therefore it is associated with a short time delay, less than the neutral voltage displacement protection operating time. It is recommended that the terminal side CTs should be used for this application.

2.5 Phase Fault Overcurrent Protection (50/51)

A four stage directional/non-directional overcurrent element is provided in the P34x relays. This element can be used to provide time delayed back-up protection for the system and high set protection providing fast operation for machine faults.

In the P343/P344/P345 the 3 phase current source can be selected using the I> CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting. In the standard connection diagrams in the installation chapter, *P34x/EN IN*, IA-1/IB-1/IC-1 is connected to the neutral side CTs and IA-2/IB-2/IC-2 is connected to the terminal side CTs. The overcurrent protection can therefore be selected for the HV or LV winding phase fault protection for generator-transformer applications.

The first two stages have a time delayed characteristic that can be set as either Inverse Definite Minimum Time (IDMT) or Definite Time (DT). The third and fourth stages have a definite time delay, which can be set to zero to produce instantaneous operation. Each stage can be selectively enabled or disabled.

2.5.1 Application of Timer Hold Facility

This feature may be useful in certain applications, for example when grading with electromechanical overcurrent relays which have inherent reset time delays. It will also enable the element to become sensitive to a pole slipping condition where the element will cyclically operate as the machine slips successive poles.

Another situation where the timer hold facility may be used to reduce fault clearance times is where intermittent faults may be experienced. 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.

2.5.2 Setting Guidelines for Overcurrent Protection

The first and second stage of overcurrent protection can be selected by setting I>1/2 Function to any of the inverse or DT settings. The first and second stage is disabled if I>1/2 Function is set to Disabled.

The first or second stage can provide back-up protection for faults on the generator and the system. As such it should be coordinated with downstream protection to provide discrimination for system faults, setting the current threshold (I>1/2 Current Set), and the time delay.

I>1 TMS	For IEC curves;
I>1 Time Dial	For US/IEEE curves;
I>1 Time Delay	For definite time accordingly.

To provide back-up protection for the generator and system, the element must be supplied from CTs connected in the generator tails (neutral). If terminal end CTs are used, the element will provide protection for the system only, unless the generator is connected in parallel to a second source of supply.

The third and fourth stages of overcurrent protection can be enabled by setting I>3/4 Function to DT, providing a definite time operating characteristic. The third and fourth stages are disabled if I>3/4 Function is set to Disabled. Where terminal CTs are used, the third or fourth stage can be set as an instantaneous overcurrent protection, providing protection against internal faults on the machine. The current setting of the third or fourth stage, I>3/4 Current Set, could be set to 120% of the maximum fault rating of the generator, typically 8 x full load current. The operating time, I>3/4 Time Delay, should be set to 0s to give instantaneous operation. The stage will therefore be stable for external faults where the fault current from the generator will be below the stage current setting. For faults within the machine, the fault current will be supplied from the system and will be above the second stage current setting, resulting in fast clearance of the internal fault.

For generator-transformer applications the overcurrent protection can be selected for the HV or LV winding phase fault protection using the I> CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting.

Directional overcurrent protection is not generally required for generator applications as the generator neutral CTs are normally used for overcurrent protection but it is included for consistency with other products.

2.6 Negative Phase Sequence (NPS) Overcurrent Protection (46OC)

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, 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. Therefore a negative phase sequence overcurrent element can operate for both phase-phase and phase-earth faults.

The following section describes how negative phase sequence overcurrent protection may be applied in conjunction with standard overcurrent and earth fault protection to alleviate some less common application difficulties.

- Negative phase sequence overcurrent elements give greater sensitivity to resistive phase to phase faults, where phase overcurrent elements may not operate. Voltage dependent overcurrent and underimpedance protection is commonly used to provide more sensitive back-up protection for system phase faults on a generator than simple overcurrent protection. However, negative phase sequence overcurrent protection can also be used to provide sensitive back-up protection for phase-phase faults.

Note	*NPS overcurrent protection will not provide any system back-up protection for three-phase faults.*

- 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 negative phase sequence overcurrent element may be employed to provide time-delayed back-up protection for any uncleared asymmetrical faults downstream.

- For rotating machines a large amount of negative phase sequence current can be a dangerous condition for the machine due to its heating effect on the rotor. Therefore a negative phase sequence overcurrent element may be applied to provide back-up protection to the negative phase sequence thermal protection that is normally applied to a rotating machine, see section 2.15.
- It may be required to simply alarm for the presence of negative phase sequence currents on the system. Operators may then investigate the cause of the unbalance.
- A directional negative phase sequence overcurrent element can be used to prevent maloperation of the zero sequence overvoltage protection used to provide interturn protection for a system earth or phase-phase fault, see section 2.2.3.4.

2.6.1 Setting Guidelines for NPS Overcurrent Protection

In the P343/P344/P345 the 3-phase current source can be selected using the I2> CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting. In the standard connection diagrams in the installation chapter, *P34x/EN IN*, IA-1/IB-1/IC-1 is connected to the neutral side CTs and IA-2/IB-2/IC-2 is connected to the terminal side CTs. The NPS overcurrent protection can therefore be selected for the HV or LV winding phase fault protection for generator-transformer applications. When directional NPS overcurrent protection is used with the neutral voltage and NPS overpower for generator interturn protection the terminal side CTs should be used, see section 2.2.3.4.1.

The current pick-up threshold must be set higher than the negative phase sequence 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 negative phase sequence current, and setting at least 20% above this figure.

Where the negative phase sequence element is required to operate for specific uncleared asymmetric faults, a precise threshold setting would have to be based on 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 negative phase sequence fault current contribution to a specific remote fault condition.

Note	*If the required fault study information is unavailable, the setting must adhere to the minimum threshold previously outlined, employing a suitable time delay for coordination with downstream devices. This is vital to prevent unnecessary interruption of the supply resulting from inadvertent operation of this element.*

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 or used in conjunction with neutral voltage displacement protection and NPS overpower protection for interturn protection. Therefore in practice, it would be associated with a long time delay if used to provide back-up protection or an alarm. If this protection is used as a directional NPS overcurrent element in conjunction with neutral voltage displacement and NPS overpower for interturn protection then a short time delay (less than the neutral voltage displacement operating time) is desirable to ensure stability for external earth or phase-phase faults.

Where the protection is used for back-up protection or as an alarm 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, such as:

- Phase overcurrent elements
- Earth fault elements
- System back-up protection - voltage dependent overcurrent/underimpedance
- Broken conductor elements
- Negative phase sequence influenced thermal elements

2.6.2 Directionalizing the Negative Phase Sequence Overcurrent Element

To determine if a phase-phase or phase-earth fault is internal or external to the machine directional control of the element should be employed.

Directionality is achieved by comparison of the angle between the inverse of the negative phase sequence voltage (-V2) and the negative phase sequence current (I2). 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 on 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.

2.7 System Back-Up Protection (51V/21)

A generator is a source of electrical power and will supply system faults until they are cleared by system protection. Back-up protection must be applied at the generator so that faults are cleared in the event of downstream protection/circuit breakers failing to operate.

The fault current supplied by a generator will vary during a fault condition as indicated by the generator decrement curve, shown in Figure 32. The fault current response is determined by the action of the automatic voltage regulator on the machine. With some generators, fault current initiates an AVR 'boost' circuit that maintains the fault current at a relatively high level. If the voltage regulator is set to manual control or no boost circuit exists, the fault current can be severely restricted, leading to slow operation of back-up protection for system faults. In the worst case the fault current will fall below the full load rating of the machine, so simple overcurrent protection with a setting above full load current, cannot operate.

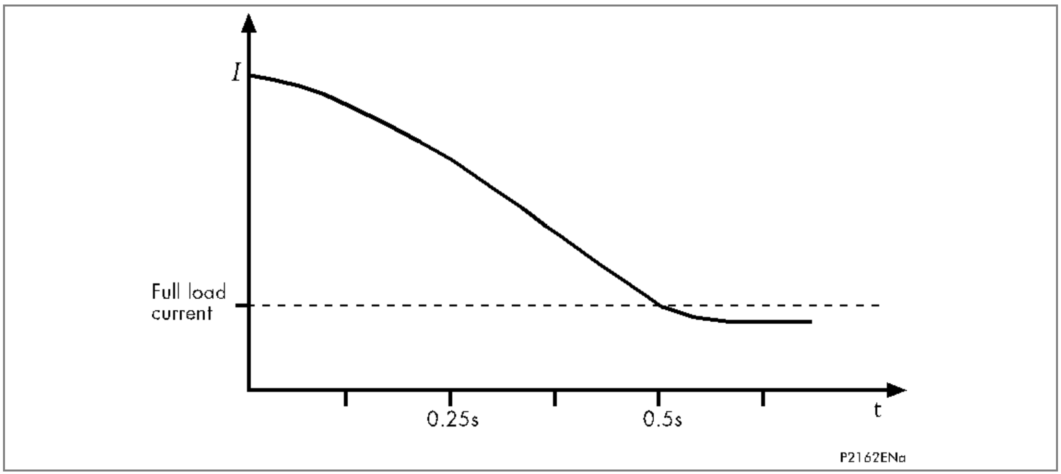


Figure 32 - Typical generator fault current decrement curve

System back-up protection must operate quickly during a fault and must not operate for load conditions. To achieve these two objectives, two methods of system back-up protection are commonly used:

1. Voltage dependant overcurrent protection. The presence of a fault is detected by an under voltage element and the relay setting is adjusted accordingly. Voltage dependant overcurrent protection can be operated in a 'voltage controlled' or 'voltage restrained' mode.
1. Under impedance protection. This element is set to monitor the system impedance at the terminals of the machine. If the impedance measured falls below a set threshold then the element will operate.

Customer preference will determine the mode of operation. However, subtle application benefits can be claimed for one form of protection over the other in certain circumstances.

A single protection element that can be configured as either voltage dependant overcurrent or under impedance is provided in the P34x & P391 relay for system back-up protection. The operation of the element is described in the following sections.

The function operates from the phase currents measured by the IA, IB and IC measurement inputs on the relay.

2.7.1 Voltage Dependant Overcurrent Protection

The generator terminal voltage will drop during fault conditions and so a voltage measuring element can be used to control the current setting of this element. On detection of a fault the current setting is reduced by a factor K. This ensures faults are cleared in spite of the presence of the generator decrement characteristic. Line voltages are used to control each phase overcurrent element as shown in Table 4.

Phase current	Control voltage
Ia	Vab
Ib	Vbc
Ic	Vca

Table 4 - Control voltages for phase currents

A single stage, non-directional overcurrent element is provided. The element has a time delayed characteristic that can be set as either Inverse Definite Minimum Time (IDMT) or Definite Time (DT). The element can be fed from CTs at the terminal or neutral end of the generator.

If voltage dependant overcurrent operation is selected, the element can be set in one of two modes, voltage controlled overcurrent or voltage restrained overcurrent. Where the generator is directly connected to a busbar, voltage controlled overcurrent protection may be preferred.

2.7.1.1 Setting Guidelines for Voltage Controlled Overcurrent Function

Voltage controlled overcurrent protection can be selected by setting Backup Function to Voltage Controlled. The protection is disabled if Backup Function is set to Disabled.

The current setting, V Dep OC I> Set, should be set to have a primary operating value in excess of the maximum generator load current.

The current setting multiplying factor, V Dep OC k Set, governs the protection function setting under low voltage conditions. This should be set to give a primary operating current less than 50% of the minimum steady-state fault current for a multi-phase fault at the remote end of a feeder, with the generator being the only source. This ensures the element will provide adequate back-up protection for an uncleared fault on that feeder.

The voltage-controlled protection fault characteristic should coordinate with outgoing feeder protection for a feeder fault under minimum plant conditions. The operating characteristic, V Dep OC Char and the time delay (V Dep OC TMS – for IEC curves; V Dep OC T Dial – for US/IEEE curves; V Dep OC Delay for definite time) should be selected accordingly.

Where parallel sources are present, a remote feeder fault may not result in a sufficient voltage reduction to enable the fault characteristic. For such applications a time undervoltage element can be used to clear the fault (see section 2.8). Alternatively, negative sequence thermal protection could be used (see section 2.15).

The voltage setting for switching between load and fault characteristics, V Dep OC V<1 Set, should be greater than the terminal voltage for a fault where back-up protection is required. On a solidly earthed system the element can be made insensitive to earth faults by ensuring that the voltage setting is below 57%Vn (minimum phase to phase voltage for a single phase to earth fault). A typical setting would be 30%Vn. A voltage setting higher than 57%Vn will allow the relay operating characteristic to change for both phase and earth faults.

More accurate settings may be determined with reference to the following equations.

The minimum fault current for a remote-end multi-phase fault on a feeder can be determined as follows. This calculation is based on no-load excitation being applied and no field-forcing or AVR action during the fault.

Three-phase fault:

$$I_f = \frac{E_n}{\sqrt{(nR_f)^2 + (X_s + nX_f)^2}}$$

Phase to phase fault:

$$I_f = \frac{\sqrt{3E_n}}{\sqrt{(2nR_f)^2 + (X_s + X_2 + 2nX_f)^2}}$$

Where:

I_f = Minimum generator primary current seen for a multi-phase feeder-end fault

E_n = No-load phase-neutral internal e.m.f. of generator

X_s = Direct-axis synchronous reactance of the generator
X_2 = Negative phase sequence reactance of the generator
R_f = Feeder positive phase sequence resistance
X_f = Feeder positive phase sequence reactance
n = Number of parallel generators

The steady-state voltage seen by the relay under external fault conditions can be deduced as follows:

Three-phase fault: $$V_{\varnothing\text{-}\varnothing} = \frac{E_n \sqrt{3\left((nR_f)^2 + (nX_f)^2\right)}}{\sqrt{(nR_f)^2 + (X_s + nX_f)^2}}$$

Phase-phase fault: $$V_{\varnothing\text{-}\varnothing} = \frac{2E_n \sqrt{3\left((nR_f)^2 + (nX_f)^2\right)}}{\sqrt{(2nR_f)^2 + (X_s + 2nX_f)^2}}$$

The current setting multiplier, V Dep OC k Set, must be set such that V Dep OC k Set x V Dep OC I Set is less than If as calculated above. The voltage setting, V Dep OC V<1 Set, must be greater than. $V_{\varnothing\text{-}\varnothing}$ as calculated above.

The voltage controlled overcurrent protection is provided with a timer hold facility. Setting the hold timer to a value other than zero delays the resetting of the protection element timers for this period.

2.7.1.2 Voltage Vector Transformation for Use with Delta-Star Transformers

To improve the sensitivity of the voltage dependant overcurrent and underimpedance protection function, for HV phase-phase faults fed via a Yd1 or Yd11 step-up transformer, the appropriate voltage signal transformation facility should be switched in as part of the P34x settings. In the past, such correction of voltage signals has been addressed by adopting phase-neutral voltage measurement or the use of a star/delta interposing VT. Such an approach cannot be adopted with P34x since the relay voltage inputs are common to other protection and measurement functions that would be undesirably affected by voltage signal correction.

If a generator is connected to a busbar through a delta-star step-up transformer, a solid phase-phase fault on the high voltage (HV) busbar will only result in a partial phase-phase voltage collapse at the generator terminals. The voltage dependent overcurrent and underimpedance functions (51 V/21) may not be sensitive enough to detect such faults. On the other hand, a phase-earth fault on the HV side would yield a low phase-phase voltage on the delta side, and the (51 V/21) may respond inappropriately. Such faults should be dealt with by the HV earth fault protection.

In order for the voltage dependent overcurrent function to coordinate correctly with other relays on the system, where there is a delta-star step-up transformer, an internal voltage vector transformation feature is provided. This allows the 51V/21 protection to make use of derived voltages with the same phase-phase relationship as the HV side voltages.

If the Delta-Star setting option is selected for the Vector Rotation setting, the voltage dependencies for the three voltage dependent overcurrent or underimpedance elements are as follows. The voltage dependencies are for a Yd11 step-up transformer, however, the voltage magnitudes are also applicable for a Yd1, Yd5 or Yd7 step-up transformer application.

For Ia or Za V = magnitude (Vab - Vca)/√3

For Ib or Zb V = magnitude (Vbc - Vab)/√3

For Ic or Zc V = magnitude (Vca - Vbc)/√3

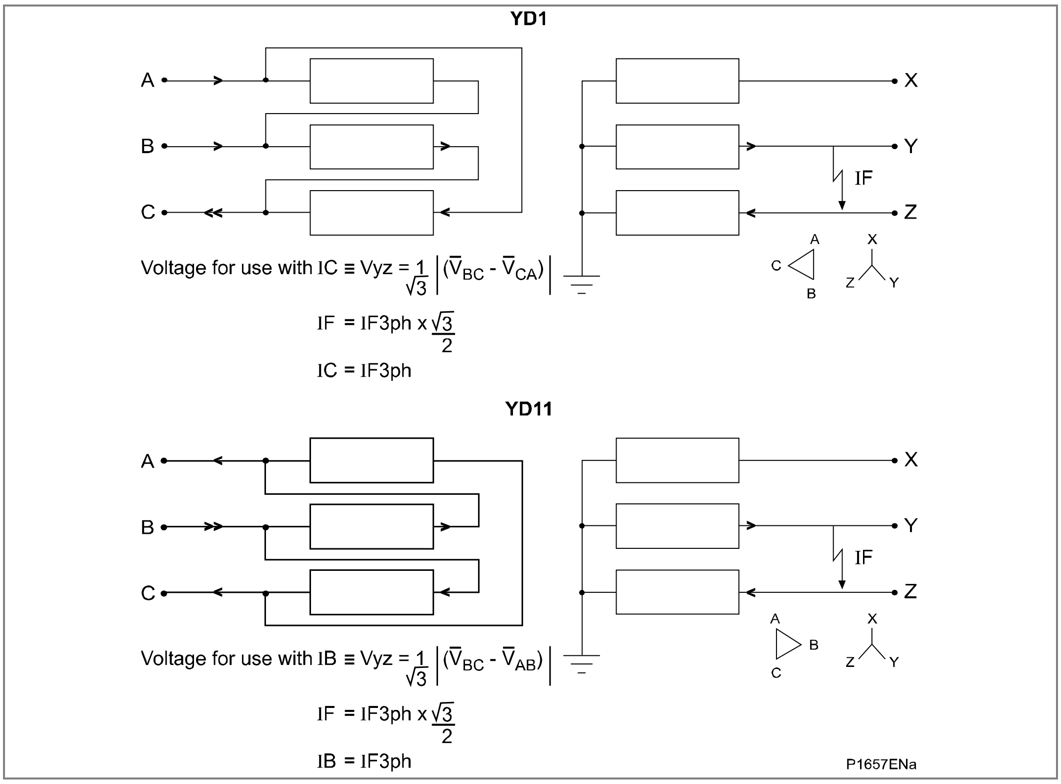


Figure 33 - Voltage vector transformation for a delta-star transformer

2.7.1.3 Setting Guidelines for Voltage Restrained Overcurrent Function

Voltage restrained overcurrent protection can be selected by setting Backup Function to Voltage Restrained. The protection is disabled if Backup Function is set to Disabled.

The performance criteria on which the settings of the voltage-restrained overcurrent protection function should be based are similar to those discussed for the voltage controlled mode in section 2.7.1.1. Coordination with downstream protection should be ensured when the relay is on its most sensitive settings i.e. for voltages less than the V Dep OC V<2 Set setting. Current threshold, characteristic and time delay can be selected as described for the Voltage Controlled function described in section 2.7.1.1.

The voltage restrained overcurrent function should be able to respond to a remote-end fault on an outgoing feeder. Where the generator is connected via a step up transformer, zero sequence quantities will not be present at the relay location for HV side earth faults. Therefore it would be normal to use negative sequence thermal or NPS overcurrent protection for back-up protection in this case. The negative phase sequence thermal and NPS overcurrent elements will also provide back-up protection for phase to phase faults. For this reason, consideration will only be given to the detection of a remote-end three-phase feeder fault, with the protected machine as the only source.

For a remote-end, three-phase fault, it is possible to calculate the level of current and voltage at the relay location. Ensure the relay current setting, V Dep OC k Set x V Dep OC I Set, is set to less than 50% of the fault current. Also, set the voltage threshold, V Dep OC V<2 Set to a value above the voltage measured at the relay.

There would be no need for further reduction in the current setting for closer faults, which would yield higher currents and lower voltages. Further reduction in the current setting for closer faults may make coordination with local feeder overcurrent protection more difficult (if this is not already a problem).

The steady-state primary current and voltage magnitudes seen for a feeder remote-end three-phase fault are given as follows:

Where:

I_f = Minimum generator primary current seen for a multi-phase feeder-end fault

E_n = No-load phase-neutral internal e.m.f. of generator

X_s = Direct-axis synchronous reactance of the generator
X_2 = Negative phase sequence reactance of the generator
X_t = Step-up transformer reactance
R_f = Feeder positive phase sequence resistance
X_f = Feeder positive phase sequence reactance
n = Number of parallel generators

All above quantities refer to the generator side of the transformer.

The upper voltage threshold setting, V Dep OC V<1 Set, should be set below the minimum corrected phase-phase voltage level for a close-up HV earth fault, to ensure that the element is insensitive to the fault. In the case of HV solid earthing, this voltage would be a minimum of 57% of the nominal operating voltage.

The voltage restrained overcurrent protection is provided with a timer hold facility, as described in section 2.7.1.1. Setting the hold timer to a value other than zero, delays the resetting of the protection element timers for this period.

2.7.2 Under Impedance Protection

Under impedance protection is an alternative to voltage dependent overcurrent protection and is often preferred due to its ease of setting. The definite time delay may be difficult to provide coordination with downstream inverse time overcurrent protections but will be easier to coordinate with distance protection.

The impedance measurement is based on phase-phase voltage and phase-neutral current. This is to make the protection immune to earth faults on the low voltage side of the generator-transformer or for a machine directly connected to the busbars. The main purpose is to provide back-up protection for phase-phase and three-phase faults. Earth fault protection should be allowed to clear earth faults.

The underimpedance protection has 2 stages of impedance protection. For generator transformer applications one stage could be used to reach into the step-up transformer and one stage to reach further into the power system to provide 2 zones of protection.

2.7.2.1 Setting Guidelines for Under Impedance Function

Under impedance protection can be selected by setting Backup Function to Under Impedance. The protection is disabled if Backup Function is set to Disabled. As phase-phase voltage is used in the measurement of impedance the impedance settings should be increased by a factor of √3 to account for this for directly connected machines as well as indirectly (transformer) connected machines. For machines connected to the busbars via a delta-star step-up transformer the Delta-Star setting option should be selected in the Vector Rotation setting, see section 2.7.1.2.

The first stage impedance setting, Z<1 Setting, should be set to 70% of the maximum load impedance. This gives an adequate margin for short time overloads, voltage variation etc., whilst giving adequate back-up protection for generator, generator-transformer and busbar faults.

For example $Z{<}1 = \sqrt{3} \times 0.7 \times \left(\dfrac{\text{Vph - n}}{\text{Iflc x 1.2}} \right)$

allowing for a 20% overload of the generator full load current.

The second stage impedance setting Z<2 Setting, could be set to 50 - 60% of the generator-transformer impedance. This stage can then be used to obtain faster operation for faults closer to the generator.

The time delay, Z<1 Time Delay should allow coordination with downstream overcurrent and distance protection devices and with the zone 2 underimpedance protection. The time delay, Z<2 Time Delay should allow coordination with generator and transformer LV phase fault protection.

The under impedance protection is provided with a timer hold facility, as described in section 2.7.1.1. Setting the hold timer, Z< tRESET, to a value other than zero, delays the resetting of the protection element timer for this period.

2.8 Undervoltage Protection Function (27)

Undervoltage protection is not a commonly specified requirement for generator protection schemes. However, undervoltage elements are sometimes used as interlocking elements for other types of protection, such as field failure. In this relay, this type of interlocking can be arranged via the relay scheme logic. Undervoltage protection may also be used for back-up protection where it may be difficult to provide adequate sensitivity with voltage dependant/underimpedance/negative phase sequence elements.

For an isolated generator, or isolated set of generators, a prolonged undervoltage condition could arise for a number of reasons. One reason would be failure of automatic voltage regulation (AVR) equipment. Where an auxiliary transformer is used to supply generator ancillary equipment, such as boiler-feed pumps, air-blowers, lubrication pumps etc., a prolonged undervoltage condition could adversely affect the performance of the machine. If such a situation is envisaged, the application of time-delayed undervoltage protection might be a consideration.

2.8.1 Setting Guidelines for Undervoltage Protection

Stage 1 may be selected as either IDMT (for inverse time delayed operation), DT (for definite time delayed operation) or Disabled, within the V<1 Function cell. Stage 2 is definite time only and is Enabled/Disabled in the V<2 Status cell. The time delay (V<1 TMS - for IDMT curve; V<1 Time Delay, V<2 Time Delay - for definite time) should be adjusted accordingly.

The undervoltage protection can be set to operate from phase-phase or phase-neutral voltage as selected by V< Measur't Mode. Single or three-phase operation can be selected in V<1 Operate Mode. When Any Phase is selected, the element will operate if any phase voltage falls below setting, when Three-phase is selected the element will operate when all three-phase voltages are below the setting.

If the undervoltage protection function is to be used for back-up protection, the voltage setting, V<1 Voltage Set, should be set above the steady-state phase-phase voltage seen by the relay for a three-phase fault at the remote end of any feeder connected to the generator bus. Allowances should be made for the fault current contribution of parallel generators, which will tend to keep the generator voltage up. If the element is set to operate from phase to phase voltages operation for earth faults can be minimized, i.e. set V< Measur't. Mode to Phase-Phase. To allow detection of any phase to phase fault, V< Operate Mode should be set to Any-Phase. Equations for determining the phase-phase voltage seen by the relay under such circumstances are given in section 2.7.1.1

The operating characteristic would normally be set to definite time, set V<1 Function to DT. The time delay, V<1 Time Delay, should be set to coordinate with downstream protections and the System Back-up protection of the relay, if enabled. Additionally, the delay should be long enough to prevent unwanted operation of the under voltage protection for transient voltage dips. These may occur during clearance of faults further into the power system or by starting of local machines. The required time delay would typically be in excess of 3s - 5s.

The second stage can be used as an alarm stage to warn the user of unusual voltage conditions so that corrections can be made. This could be useful if the machine is being operated with the AVR selected to manual control.

Where the relay is used to provide the protection required for connecting the generator in parallel with the local electricity supply system (e.g. requirements of G59 in the UK), the local electricity supply authority may advise settings for the element. The settings must prevent the generator from exporting power to the system with voltage outside of the statutory limits imposed on the supply authority.

To prevent operation of any under voltage stage during normal shutdown of the generator "poledead" logic is included in the relay. This is facilitated by selecting V Poledead Inh to Enabled. This will ensure that when a poledead condition is detected (i.e. all phase currents below the undercurrent threshold or CB Open, as determined by an opto isolator and the PSL) the undervoltage element will be inhibited.

2.9 Overvoltage Protection (59)

A generator terminal overvoltage condition could arise when the generator is running but not connected to a power system, or where a generator is providing power to an islanded power system. Such an over voltage could arise in the event of a fault with automatic voltage regulating equipment or if the voltage regulator is set for manual control and an operator error is made. Overvoltage protection should be set to prevent possible damage to generator insulation, prolonged overfluxing of the generating plant, or damage to power system loads.

When a generator is synchronized to a power system with other sources, an overvoltage could arise if the generator is lightly loaded supplying a high level of power system capacitive charging current. An overvoltage condition might also be possible following a system separation, where a generator might experience full-load rejection whilst still being connected to part of the original power system. The automatic voltage regulating equipment and machine governor should quickly respond to correct the overvoltage condition in these cases. However, overvoltage protection is advisable to cater for a possible failure of the voltage regulator or for the regulator having been set to manual control. In the case of Hydro generators, the response time of the speed governing equipment can be so slow that transient over speeding up to 200% of nominal speed could occur. Even with voltage regulator action, such over speeding can result in a transient over voltage as high as 150%. Such a high voltage could result in rapid insulation damage.

2.9.1 Setting Guidelines for Overvoltage Protection

Stage 1 may be selected as either IDMT (for inverse time delayed operation), DT (for definite time delayed operation) or Disabled, within the V>1 Function cell. Stage 2 has a definite time delayed characteristic and is Enabled/Disabled in the V>2 Status cell. The time delay (V>1 TMS - for IDMT curve; V>1 Time Delay, V>2 Time Delay - for definite time) should be selected accordingly.

The overvoltage protection can be set to operate from Phase-Phase or Phase-Neutral voltage as selected by V> Measur't Mode cell. Single or three-phase operation can be selected in V> Operate Mode cell. When Any Phase is selected the element will operate if any phase voltage is above setting, when Three-phase is selected the element will operate when all three-phase voltages are above the setting.

Generators can typically withstand a 5% overvoltage condition continuously. The withstand times for higher overvoltages should be declared by the generator manufacturer.

To prevent operation during earth faults, the element should operate from the phase-phase voltages, to achieve this V>1 Measur't Mode can be set to Phase-Phase with V>1 Operating Mode set to Three-phase. The overvoltage threshold, V>1 Voltage Set, should typically be set to 100% - 120% of the nominal phase-phase voltage seen by the relay. The time delay, V>1 Time Delay, should be set to prevent unwanted tripping of the delayed overvoltage protection function due to transient over voltages that do not pose a risk to the generating plant; e.g. following load rejection where correct AVR/Governor control occurs. The typical delay to be applied would be 1s - 3s, with a longer delay being applied for lower voltage threshold settings.

The second stage can be used to provide instantaneous high-set over voltage protection. The typical threshold setting to be applied, V>2 Voltage Set, would be 130 - 150% of the nominal phase-phase voltage seen by the relay, depending on plant manufacturers' advice. For instantaneous operation, the time delay, V>2 Time Delay, should be set to 0 s.

Where the relay is used to provide the protection required for connecting the generator in parallel with the local electricity supply system (e.g. requirements of G59 in the UK), the local electricity supply authority may advise settings for the element. The settings must prevent the generator from exporting power to the system with voltages outside of the statutory limits imposed on the supply authority.

If phase to neutral operation is selected, care must be taken to ensure that the element will grade with downstream protections during earth faults, where the phase-neutral voltage can rise significantly.

2.10 Negative Phase Sequence (NPS) Overvoltage Protection (47)

Where an incoming feeder is supplying a switchboard that is feeding rotating plant (e.g. a motor), correct phasing and balance of the ac supply is essential. Incorrect phase rotation could result in any connected machines rotating in the wrong direction. For some hydro machines two-phases can be swapped to allow the machine to rotate in a different direction to act as a generator or a motor pumping water.

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% negative phase sequence voltage only.

For such applications the P34x relay includes a negative phase sequence overvoltage element. This element monitors the input voltage rotation and magnitude (normally from a bus connected voltage transformer). This element could be used as a check for hydro machines that the phase rotation is correct to operate the machine in the selected mode as a generator or motor.

The NPS overvoltage element can also be used to provide an additional check to indicate a phase-earth or phase-phase fault is present for voltage controlled overcurrent protection in the PSL. In this application the NPS overvoltage protection can be accelerated when the CB is closed. Typically, the operating time of the NPS overvoltage start is slowed (typical operating time is <60 ms) to prevent incorrect operation when closing the CB due to pole scattering. However, when the CB is closed there is no need to inherently slow the protection start (typical accelerated operating time is <40 ms). The V2>1 Accelerate: DDB 554 signal connected to the CB Closed 3 Ph: DDB 1043 signal can be used to accelerate the protection start.

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 5 s.

2.11 Underfrequency Protection (81U)

Underfrequency operation of a generator will occur when the power system load exceeds the prime mover capability of an islanded generator or group of generators. Power system overloading can arise when a power system becomes split, with load left connected to a set of 'islanded' generators that is in excess of their capacity. Such events could be compensated for by automatic load shedding. In this case, underfrequency operation would be a transient condition. In the event of the load shedding being unsuccessful, the generators should be provided with back-up underfrequency protection.

An underfrequency condition, at nominal voltage, may result in some over fluxing of a generator and its associated electrical plant. However, the more critical considerations would be in relation to blade stresses being incurred with high-speed turbine generators; especially steam-driven sets. When not running at nominal frequency, abnormal blade resonance's can be set up that, if prolonged, could lead to turbine disc component fractures. Such effects can be accumulative and so operation at frequencies away from nominal should be limited as much as possible, to avoid the need for early plant inspections/overhaul. Underfrequency running is difficult to contend with, since there is little action that can be taken at the generating station in the event of overloading, other than to shut the generator down.

Four independent definite time-delayed stages of underfrequency protection are offered. Two additional overfrequency stages can also be reconfigured as underfrequency protection by reprogramming the Programmable Scheme Logic. As well as being able to initiate generator tripping, the underfrequency protection can also be arranged to initiate local load-shedding, where appropriate. Selectable fixed scheme logic is provided to allow each stage of underfrequency protection to be disabled when the outgoing CB is open, to prevent unnecessary load tripping.

2.11.1 Setting Guidelines for Underfrequency Protection

Each stage of underfrequency protection may be selected as Enabled or Disabled, within the F<x Status cells. The frequency pickup setting, F<x Setting, and time delays, F<x Time Delay, for each stage should be selected accordingly.

The protection function should be set so that declared frequency-time limits for the generating set are not infringed. Typically, a 10% underfrequency condition should be continuously sustainable.

For industrial generation schemes, where generation and loads may be under common control/ownership, the P34x & P391 underfrequency protection function could be used to initiate local system load shedding. Four stage underfrequency/load shedding can be provided. The final stage of underfrequency protection should be used to trip the generator.

Where separate load shedding equipment is provided, the underfrequency protection should coordinate with it. This will ensure that generator tripping will not occur in the event of successful load shedding following a system overload. Two stages of underfrequency protection could be set-up, as shown in Figure 34, to coordinate with multi-stage system load shedding.

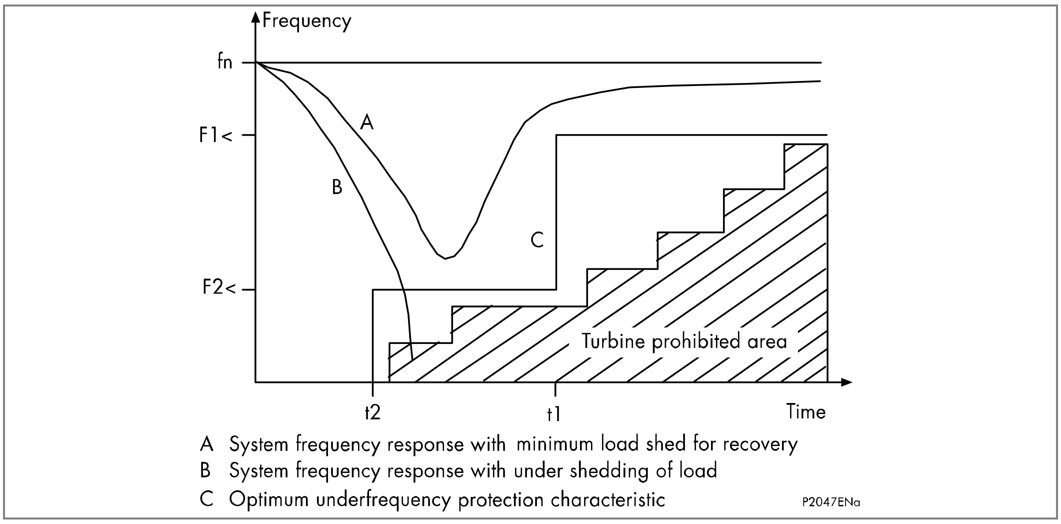


Figure 34 - Coordination of underfrequency protection function with system load shedding

To prevent operation of any underfrequency stage during normal shutdown of the generator “poledead” logic is included in the relay. This is facilitated for each stage by setting the relevant bit in F< Function Link. For example if F< Function Link is set to 0111, Stage 1, 2 and 3 of underfrequency protection will be blocked when the generator CB is open. Selective blocking of the frequency protection stages in this way will allow a single stage of protection to be enabled during synchronization or offline running to prevent unsynchronized overfluxing of the machine. When the machine is synchronized, and the CB closed, all stages of frequency protection will be enabled providing a multi-stage load shed scheme if desired.

Where the relay is used to provide the protection required for connecting the generator in parallel with the local electricity supply system (e.g. requirements of G59 in the UK), the local electricity supply authority may advise settings for the element. The settings must prevent the generator from exporting power to the system with frequency outside of the statutory limits imposed on the supply authority. Where the local external load exceeds the generator capacity, underfrequency protection may be used to provide ‘Loss of Mains’ protection.

2.12 Overfrequency Protection Function (81O)

Overfrequency running of a generator arises when the mechanical power input to the alternator is in excess of the electrical load and mechanical losses. The most common occurrence of overfrequency is after substantial loss of load. When a rise in running speed occurs, the governor should quickly respond to reduce the mechanical input power, so that normal running speed is quickly regained. Overfrequency protection may be required as a back-up protection function to cater for governor or throttle control failure following loss of load or during unsynchronized running.

Moderate overfrequency operation of a generator is not as potentially threatening to the generator and other electrical plant as underfrequency running. Action can be taken at the generating plant to correct the situation without necessarily shutting down the generator.

Severe overfrequency operation of a high-speed generating set could result in plant damage, as described in section 2.16, as a result of the high centrifugal forces that would be imposed on rotating components.

Two independent time-delayed stages of overfrequency protection are provided.

2.12.1 Setting Guidelines for Overfrequency Protection

Each stage of overfrequency protection may be selected as Enabled or Disabled, within the F>x Status cells. The frequency pickup setting, F>x Setting, and time delays, F>x Time Delay, for each stage should be selected accordingly.

The P34x overfrequency settings should be selected to coordinate with normal, transient overfrequency excursions following full-load rejection. The generator manufacturer should declare the expected transient overfrequency behavior that should comply with international governor response standards. A typical overfrequency setting would be 10% above nominal.

Where the relay is used to provide the protection required for connecting the generator in parallel with the local electricity supply system (e.g. requirements of G59 in the UK), the local electricity supply authority may advise settings for the element. The settings must prevent the generator from exporting power to the system with frequency outside of the statutory limits imposed on the supply authority.

2.13 Generator Turbine Abnormal Frequency Protection (81AB)

Generator sets are normally rated for a lifetime of operation within a defined operating frequency band. Operation outside of this “normal” region can produce mechanical stress in the turbine blades due to their natural resonance and reduce the useful life of the generator. Turbine manufacturers provide accumulative time limits for abnormal frequency operation, usually in the form of a permissible operating time within a specified frequency band. This calls for the use of accumulative time measurements for storing the time spent in running at abnormal speed within each band. These turbine capability limitations generally apply to steam turbine generators.

Six bands of generator abnormal protection are provided within the P34x relays. Each band has its own frequency limit settings and an individual accumulative time measurement. Operation within each of these bands is monitored and the time added to a cumulative timer, stored within the battery backed RAM. This ensures that on loss of auxiliary supply to the relay, the information is not lost. An individual dead band time delay setting is provided for each band. Within this dead band time delay, the frequency is allowed to stay inside the band without initiating the accumulative time measurement. This delay allows the blade's resonance during under frequency conditions to be established first, therefore avoiding unnecessary accumulation of time. The delay therefore does not contribute to the accumulated time. It is recommended by the IEEE Guide for Abnormal Frequency Protection for Power Generating Plants (IEEE C37.106) to be around 10 cycles. Note that the dead band delay has no effect on the initiation of the start signals. Therefore the start signals can be used during commissioning and maintenance (by setting the dead times temporarily or switching to a different setting group with a high value) to test the frequency band's pick-up and drop-off without adding to the accumulated times. Time accumulation will stop and all the start signals will be reset if the Frequency Not Found DDB 1068 is set.

It is normally recommended that the turbine abnormal frequency protection system should be in-service whenever the unit is synchronized to the system, or while separated from the system but supplying auxiliary load. An inhibit signal is available to inhibit the time accumulation when the generator is off-line, i.e. the circuit breaker is open.

The trip output is latched and can only be reset only if any of the following conditions occur:

- The accumulative time is reset, or
- The corresponding band is disabled, or
- The entire abnormal frequency protection is disabled, or
- The Inhibit DDB Turbine F Inh is energized.

2.13.1 Setting Guidelines

The withstand of the generator for abnormal speeds is normally given by the generator manufacturer. Default settings have been provided as a guide for setting the relay.

It is recommended by the IEEE Guide for Abnormal Frequency Protection for Power Generating Plants (IEEE C37.106) that the dead band time delay should be around 10 cycles. This delay allows the blade's resonance during under frequency conditions to be established first, therefore avoiding unnecessary accumulation of time.

The trip signals of the element can be used as either an operator alarm or for shutting down the generator.

2.14 Field Failure Protection Function (40)

Complete loss of excitation may arise as a result of accidental tripping of the excitation system, an open circuit or short circuit occurring in the excitation DC circuit, flashover of any slip rings or failure of the excitation power source. The field failure protection of the P34x & P391 consists of two elements, an impedance element with two time delayed stages and a power factor alarm element.

When the excitation of a synchronous generator fails, its internal e.m.f. will decay. This results in the active power output of the machine falling and in an increasing level of reactive power being drawn from the power system. As the active power output falls, the mechanical drive can accelerate the machine so that it will gently pole slip and run at a super synchronous speed. This results in slip frequency currents being induced in the rotor body, damper windings and in the field windings. The slip-induced, low frequency rotor currents will result in a rotor flux being produced. The machine would then be excited from the power system and hence be operating as an induction generator. The ability to reach such a stabilized state will be dependent on the machine's effective speed-torque characteristic when operating as an induction generator, and also on the power system being able to supply the required reactive power without severe voltage depression.

Stable operation as an induction generator might be achieved at low slip (0.1 - 0.2% above synchronous speed), particularly in the case of salient pole machines. The machine may be able to maintain an active power output (perhaps 20 - 30% of rating) while drawing reactive power from the power system (generating at a highly leading power factor). This condition could probably be sustained for many minutes without rotor damage being incurred and may not be detectable by traditional field failure impedance characteristic elements. The P34x, however, offers a power factor alarm element in the field failure protection which can operate when the generator is running in this condition.

Cylindrical rotor machines have a much lower output capability when operating as an induction generator under excitation failure conditions. They are more likely to be pushed over the peak torque level of their induction generator speed-torque characteristic. If the peak induction generator torque level is exceeded, a machine can stabilize at a much higher level of slip (perhaps 5% above synchronous speed). When this happens, the machine will draw a very high reactive current from the power system and a stator winding current as high as 2.0 p.u. may be reached. The slip-frequency rotor currents could lead to rotor core or winding damage if the condition is sustained.

Operation as an induction generator under field failure conditions relies on the ability of the rest of the system being able to supply the required reactive power to the machine. If the system cannot supply enough reactive power the system voltage will drop and the system may become unstable. This could occur if a large generator running at high power suffers a loss of field when connected to a relatively weak system. To ensure fast tripping under this condition one of the impedance elements can be used with a short time delay. This can trip the machine quickly to preserve system stability. This element should have a small diameter to prevent tripping under power swinging conditions. The second impedance element, set with a larger diameter, can provide detection of field failure under lightly loaded conditions. This second element should be time delayed to prevent operation during power swing conditions.

The Field Failure protection impedance elements are also provided with an adjustable delay on reset (delayed drop off) timer. This time delay can be set to avoid delayed tripping that may arise as a result of cyclic operation of the impedance measuring element, during the period of pole slipping following loss of excitation. Some care would need to be exercised in setting this timer, since it could make the Field Failure protection function more likely to give an unwanted trip in the case of stable power swinging. The impedance element trip time delay should therefore be increased when setting the reset time delay.

The delay on reset timer might also be set to allow the field failure protection function to be used for detecting pole slipping of the generator when excitation is not fully lost; e.g.

following time-delayed clearance of a nearby power system fault. This subject is discussed in more detail in section 2.27.

2.14.1 Setting Guidelines for Field Failure Protection

Each stage of field failure protection may be selected as Enabled or Disabled, within the FFail1 Status, FFail2 Status cells. The power factor alarm element may be selected as Enabled or Disabled within the FFail Alm Status cell.

2.14.1.1 Impedance Element 1

To quickly detect a loss-of field condition, the diameter of the field failure impedance characteristic (FFail1 Xb1) should be set as large as possible, without conflicting with the impedance that might be seen under normal stable conditions or during stable power swing conditions.

Where a generator is operated with a rotor angle of less than 90° and never at a leading power factor, it is recommended that the diameter of the impedance characteristic, FFail1 Xb1, is set equal to the generator direct-axis synchronous reactance. The characteristic offset, FFail1 -Xa1 should be set equal to half the direct-axis transient reactance (0.5 Xd') in secondary ohms.

FFail1 Xb1 = Xd

FFail1 -Xa1 = 0.5 Xd'

Where:

Xd = Generator direct-axis synchronous reactance in ohms

Xd' = Generator direct-axis transient reactance in ohms

Where high-speed voltage regulation equipment is used it may be possible to operate generators at rotor angles up to 120°. In this case, the impedance characteristic diameter, FFail1 Xb1, should be set to 50% of the direct-axis synchronous reactance (0.5 Xd) and the offset, FFail1 -Xa1, should be set to 75% of the direct axis transient reactance (0.75 Xd').

FFail1 Xb1 = 0.5 Xd

FFail1 -Xa1 = 0.75 Xd'

The field failure protection time delay, FFail1 Time Delay, should be set to minimize the risk of operation of the protection function during stable power swings following system disturbances or synchronization. However, it should be ensured that the time delay is not so long that stator winding or rotor thermal damage will occur. A typical stator winding should be able to withstand a current of 2.0 p.u. for the order of 15 s. It may also take some time for the impedance seen at the generator terminals to enter the characteristic of the protection. A time delay less than 10 s would typically be applied. The minimum permissible delay, to avoid problems of false tripping due to stable power swings with the above impedance settings, would be of the order of 0.5 s.

The protection reset (delayed drop off) timer, FFail1 DO Timer, would typically be set to 0 s to give instantaneous reset of the stage. A setting other than 0 s can be used to provide an integrating function for instances when the impedance may cyclically enter and exit the characteristic. This can allow detection of pole slipping conditions, for more information see section 2.27. When settings other than 0 s are used the protection pick-up time delay, FFail1 Time Delay, should be increased to prevent mal-operation during stable power swing conditions.

2.14.1.2 Impedance Element 2

The second impedance element can be set to give fast operation when the field fails under high load conditions. The diameter of the characteristic, FFail2 Xb2, should be set to 1 p.u. The characteristic offset, FFail2 -Xa2, should be set equal to half the direct-axis transient reactance (0.5 Xd').

$$\text{FFail2 Xb2} = \frac{kV^2}{MVA}$$

FFail2 -Xa2 = 0.5 Xd'

This setting will detect a field failure condition from full load to about 30% load.

The time delay, FFail2 Time Delay, can be set to instantaneous, i.e. 0 s.

The protection reset (delayed drop off) timer, FFail2 DO Timer, would typically be set to 0 s to give instantaneous reset of the stage. A setting other than 0 s can be used to provide an integrating function for instances when the impedance may cyclically enter and exit the characteristic. This can allow detection of pole slipping conditions, for more information see section 2.27. When settings other than 0 s are used the protection pick-up time delay, FFail2 Time Delay, should be increased to prevent mal-operation during stable power swing conditions.

2.14.1.3 Power Factor Element

Salient pole machines can run continuously as induction generators generating significant power and operation under these conditions may not be detectable by an impedance characteristic. The power factor alarm can be used to signal to the operator that excitation has failed under these conditions.

The angle setting, FFail Alm Angle, should be set to greater than any angle that the machine could be operated at in normal running. A typical setting would be 15°, equivalent to a power factor of 0.96 leading. The power factor element time delay, FFail Alm Delay, should be set longer than the impedance element time delay setting (FFail1 Time Delay). This is to prevent operation of the alarm element under transient conditions such as power swinging and to provide discrimination where a field failure condition may not be detected by conventional field failure impedance elements.

2.15 Negative Phase Sequence Thermal Protection (46T)

Unbalanced loading results in the flow of positive and negative sequence current components. Load unbalance can arise as a result of single-phase loading, non-linear loads (involving power electronics or arc furnaces, etc.), uncleared or repetitive asymmetric faults, fuse operation, single-pole tripping and reclosing on transmission systems, broken overhead line conductors and asymmetric failures of switching devices. Any negative phase sequence component of stator current will set up a reverse-rotating component of stator flux that passes the rotor at twice synchronous speed. Such a flux component will induce double frequency eddy currents in the rotor, which can cause overheating of the rotor body, main rotor windings, damper windings etc.

Where a machine has a high continuous negative phase sequence current withstand level (I_2 amp), as in the case of typical salient-pole machines, it would not be essential to enable the NPS protection function. The NPS protection function can, however, offer a better method of responding to an uncleared asymmetric fault remote from the generator bus. As mentioned in section 2.7.1.3, it may be difficult to set the voltage dependant overcurrent protection function to detect a remote fault and co-ordinate with feeder backup protection for a close-up three-phase fault.

For high levels of negative phase sequence current, eddy current heating can be considerably in excess of the heat dissipation rate. Therefore virtually all the heat acquired during the period of unbalance will be retained within the rotor. With this assumption, the temperature attained within any critical rotor component will be dependent on the duration of the unbalance (t seconds) and the level of NPS current (I_2 per unit) and is proportional to I_2^2t. Synchronous generators are assigned a per-unit I_2^2t thermal capacity constant (Kg) to define their short time NPS current withstand ability, see column 3 in Table 1. Various rotor components have different short time thermal capacities and the most critical (lowest value of I_2^2t) should form the basis of the generator manufacturer's short time I_2^2t withstand claim.

Many traditional forms of generator NPS thermal protection relays have been designed with an extremely inverse (I_2^2t) operating time characteristic. Where the operating time of the characteristic is dependent solely on the instantaneous magnitude of negative phase sequence current present. This characteristic would be set to match the claimed generator thermal capacity. This is satisfactory when considering the effects of high values of negative phase sequence current.

For intermediate levels of NPS current, the rate of heating is slower. As a result, heat dissipation should be considered.

The basic expression of $t = K/I_2cmr$ does not cater for the effects of heat dissipation or for low standing levels of negative phase sequence current. The latter resulting in an increase in rotor temperature which remains within the machines design limits. An existing, tolerable, level of negative phase sequence current ($I_2<I_{2cmr}$), has the effect of reducing the time to reach the critical temperature level, if the negative phase sequence current level should increase beyond I_{2cmr}. The P34x NPS thermal replica is designed to overcome these problems by modeling the effects of low standing levels of negative phase sequence currents.

When the protected generator sees a reduction in negative phase sequence current, metallic rotor components will decrease in temperature. The relay is provided with a separate thermal capacity setting (I2>2 KRESET), used when there is a reduction in I_2.

The negative sequence protection element will respond to system phase to earth and phase to phase faults. Therefore the element must be set to grade with downstream earth and phase fault protections. To aid grading with downstream devices a definite minimum operating time for the operating characteristic can be set. The definite minimum time setting should be set to provide an adequate margin between the operation of the negative phase sequence thermal protection function and external protection. The coordination time margin used should be in accordance with the usual practice adopted by the customer for backup protection coordination.

For levels of negative phase sequence current that are only slightly in excess of the thermal element pick-up setting, there will be a noticeable deviation between the P34x negative phase sequence thermal protection current-time characteristic and that of the simple I_2^2t characteristic. For this reason, a maximum negative phase sequence protection trip time setting is provided. This maximum time setting also limits the tripping time of the negative phase sequence protection for levels of unbalance where there may be uncertainty about the machine's thermal withstand.

A time delayed negative sequence overcurrent alarm stage is provided to give the operator early warning of an unbalanced condition that may lead to generator tripping. This can allow corrective action to be taken to reduce the unbalance in the load.

2.15.1 Setting Guidelines for Negative Phase Sequence Thermal Protection

The alarm and trip stages of the negative phase sequence thermal protection may be selected as Enabled or Disabled, within the I2therm>1 Alarm and I2therm>2 Trip cells respectively.

Synchronous machines will be able to withstand a certain level of negative phase sequence stator current continuously. All synchronous machines will be assigned a continuous maximum negative phase sequence current (I_{2cmr} per-unit) rating by the manufacturer. For various categories of generator, minimum negative phase sequence current withstand levels have been specified by international standards, such as IEC 60034-1 and ANSI C50.13-1977 [1]. The IEC 60034-1 figures are given in Table 5.

Generator type		**Maximum I_2/I_n for continuous operation**	**Maximum $(I_2/I_n)^2t$ for operation under fault conditions, Kg**
Salient-pole:			
Indirectly cooled		0.08	20
Directly cooled (inner cooled) stator and/or field		0.05	15
Cylindrical rotor synchronous:			
Indirectly cooled rotor			
Air cooled		0.1	15
Hydrogen cooled		0.1	10
Directly cooled (inner cooled) rotor			
350 > 900 > 1250	350 MVA 900 MVA 1250 MVA 1600 MVA	0.08 * * 0.05	8 ** 5 5
* For these generators, the value of I_2/I_n is calculated as follows:			
$\frac{I_2}{I_n} = 0.8 - \frac{(S_n - 350)}{(3 * 10000)}$			
** For these generators, the value of $(I_2/I_n)^2t$ is calculated as follows:			
$\left(\frac{I_2}{I_n}\right)^2 t = 8 - 0.00545\ (S_n - 350)$			
where Sn is the rated power in MVA			

Table 5 - IEC 60034-1 Minimum negative sequence current withstand levels

To obtain correct thermal protection, the relay thermal current setting, I2therm>2 Set, and thermal capacity setting, I2therm>2 k, should be set as follows:

$$\text{I2therm>2 Set} = I_{2cmr} \times \left(\frac{I_{flc}}{I_p}\right) \times \text{In}$$

$$\text{I2therm>2 k} = \left(\frac{I_{flc}}{I_p}\right)^2 \times \text{Kg}$$

Where:

I_{2cmr}	=	Generator per unit I2 maximum withstand
K_g	=	Generator thermal capacity constant(s), see Table 1 for guidance
I_{flc}	=	Generator primary full-load current (A)
I_p	=	CT primary current rating (A)
I_n	=	Relay rated current (A)
K	=	Thermal capacity of the generator rotor (unit: second), proportional to Kg

$$K = \left(\frac{I_2}{I_p}\right) \times \left(\frac{I_2}{I_p}\right) \times t \qquad Kg = \left(\frac{I_2}{I_n}\right) \times \left(\frac{I_2}{I_n}\right) \times t$$

$$K = \left(\frac{I_p}{I_n}\right) \times \left(\frac{I_p}{I_n}\right) \times Kg$$

Unless otherwise specified, the thermal capacity constant setting used when I2 is reducing, I2therm>2 kRESET, should be set equal to the main time constant setting, I2therm>2 k Setting. A machine manufacturer may be able to advise a specific thermal capacity constant when I2 is reducing for the protected generator.

The current threshold of the alarm stage, I2therm>1 Set should be set below the thermal trip setting, I2therm>2 Set, to ensure that the alarm operates before tripping occurs. A typical alarm current setting would be 70% of the trip current setting. The alarm stage time setting, I2therm>1 Delay, must be chosen to prevent operation during system fault clearance and to ensure that unwanted alarms are not generated during normal running. A typical setting for this time delay would be 20 s.

To aid grading with downstream devices a definite minimum operating time for the operating characteristic can be set, I2therm>2 tMIN. This definite minimum time setting should be set to provide an adequate margin between the operation of the negative phase sequence thermal protection function and external protection. The coordination time margin used should be in accordance with the usual practice adopted by the customer for back-up protection coordination.

A maximum operating time for the negative phase sequence thermal characteristic may be set, I2therm>2 tMAX. This definite time setting can be used to ensure that the thermal rating of the machine is never exceeded.

2.16 Reverse Power/Over Power/Low Forward Power (32R/32O/32L)

2.16.1 Low Forward Power Protection Function

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. Large 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; e.g. stator earth fault protection for a high impedance earthed generator. For 'urgent' trips, e.g. stator current differential protection 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. During motoring conditions, it is typical for the relay to switch to another setting group with the low forward power enabled and correctly set and the protection operating mode set to Motoring.

2.16.1.1 Low Forward Power Setting Guideline

Each stage of power protection can be selected to operate as a low forward power stage by selecting the Power1 Function/Sen Power1 Func or Power2 Function/Sen Power 2 Func cell to Low Forward.

When required for interlocking of non-urgent tripping applications, the threshold setting of the low forward power protection function, P<1 Setting/Sen P<1 Setting or P<2 Setting/Sen P<2 Setting, should be less than 50% of the power level that could result in a dangerous over speed transient on loss of electrical loading. The generator set manufacturer should be consulted for a rating for the protected machine. The operating mode should be set to Generating for this application.

When required for loss of load applications, the threshold setting of the low forward power protection function, P<1 Setting/Sen P<1 Setting or P<2 Setting/Sen P<2 Setting, is system dependent, however, it is typically set to 10 - 20% below the minimum load. For example, for a minimum load of 70%Pn, the setting needs to be set at 63% - 56%Pn. The operating mode should be set to Motoring for this application.

For interlocking non-urgent trip applications the time delay associated with the low forward power protection function, Power1 TimeDelay/Sen Power1 Delay or Power2 TimeDelay/Sen Power2 Delay, could be set to zero. However, some delay is desirable so that permission for a non-urgent electrical trip is not given in the event of power fluctuations arising from sudden steam valve/throttle closure. A typical time delay for this reason is 2s.

For loss of load applications the pick up time delay, Power1 TimeDelay/Sen Power1 Delay or Power2 TimeDelay/Sen Power2 Delay, is application dependent but is normally set in excess of the time between motor starting and the load being established. Where rated power can not be reached during starting (for example where the motor is started with no load connected) and the required protection operating time is less than the time for load to be established then it will be necessary to inhibit the power protection during this period. This can be done in the PSL using AND logic and a pulse timer triggered from the motor starting to block the power protection for the required time.

The delay on reset timer, Power1 DO Timer or Power2 DO Timer, would normally be set to zero when selected to operate low forward power elements.

To prevent unwanted relay alarms and flags, a low forward power protection element can be disabled when the circuit breaker is open via ‘poledead’ logic. This is controlled by setting the power protection, inhibit cells, P1 Poledead Inh or P2 Poledead Inh, to Enabled.

2.16.2 Reverse Power Protection Function

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. Typical levels of motoring power and possible motoring damage that could occur for various types of generating plant are given in Table 6.

Prime mover	Motoring power	Possible damage (percentage rating)
Diesel Engine	5% - 25%	Risk of fire or explosion from unburned fuel
Motoring level depends on compression ratio and cylinder bore stiffness. Rapid disconnection is required to limit power loss and risk of damage.		
Gas Turbine	10% - 15% (Split-shaft) >50% (Single-shaft)	With some gear-driven sets, damage may arise due to reverse torque on gear teeth.
Compressor load on single shaft machines leads to a high motoring power compared to split-shaft machines. Rapid disconnection is required to limit power loss or damage.		
Hydraulic Turbines	0.2 - >2% (Blades out of water) >2.0% (Blades in water)	Blade and runner cavitation may occur with a long period of motoring
Power is low when blades are above tail-race water level. Hydraulic flow detection devices are often the main means of detecting loss of drive. Automatic disconnection is recommended for unattended operation.		
Steam Turbines	0.5% - 3% (Condensing sets) 3% - 6% (Non-condensing sets)	Thermal stress damage may be inflicted on low-pressure turbine blades when steam flow is not available to dissipate windage losses.
Damage may occur rapidly with non-condensing sets or when vacuum is lost with condensing sets. Reverse power protection may be used as a secondary method of detection and might only be used to raise an alarm.		

Table 6 - Motor power and possible damage for various types 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 (Power1 DO Timer/Power2 DO Timer). This delay would need to be set longer than the period for which the reverse power could fall below the power setting (P<1 Setting/Sen P<1 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, as discussed in 2.16.1. Reverse power interlocks are preferred over low forward power interlocks by some utilities.

2.16.2.1 Reverse Power Setting Guideline

Each stage of power protection can be selected to operate as a reverse power stage by selecting the Power1 Function/Sen Power1 Func or Power2 Function/Sen Power2 Func cell to Reverse.

The power threshold setting of the reverse power protection, -P>1 Setting/Sen -P>1 Setting or -P>2 Setting/Sen -P>2 Setting, should be less than 50% of the motoring power, typical values for the level of reverse power for generators are given in previous table.

For applications to detect the loss of the prime mover or for applications to provide interlocking of non-urgent trips the reverse power protection operating mode should be set to Generating.

The reverse power protection function should be time-delayed to prevent false trips or alarms being given during power system disturbances or following synchronization.

A time delay setting, Power1 TimeDelay/Sen Power1 Delay or Power2 TimeDelay/Sen Power2 Delay of 5 s should be applied typically.

The delay on reset timer, Power1 DO Timer or Power2 DO Timer, would normally be set to zero. When settings of greater than zero are used for the reset time delay, the pick up time delay setting may need to be increased to ensure that false tripping does not result in the event of a stable power swinging event.

2.16.3 Overpower 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.

2.16.3.1 Overpower Setting Guideline

Each stage of power protection can be selected to operate as an over power stage by selecting the Power1 Function/Sen Power1 Func or Power2 Function/Sen Power2 Func cell to Over.

The power threshold setting of the over power protection, P>1 Setting/Sen P>1 Setting or P>2 Setting/Sen P>2 Setting, should be set greater than the machine full load rated power.

A time delay setting, Power1 TimeDelay/Sen Power1 Delay or Power2 TimeDelay/Sen Power2 Delay should be applied.

The operating mode should be set to Motoring or Generating depending on the operating mode of the machine.

The delay on reset timer, Power1 DO Timer or Power2 DO Timer, would normally be set to zero.

2.17 Stator Earth Fault Protection Function (50N/51N)

Low voltage generators will be solidly earthed, however to limit the damage that can be caused due to earth faults, it is common for HV generators to be connected to earth via an impedance. This impedance may be fitted on the secondary side of a distribution transformer earthing arrangement. The earthing impedance is generally chosen to limit earth fault current to full load current or less.

There is a limit on the percentage of winding that can be protected by a stator earth fault element. For earth faults close to the generator neutral, the driving voltage will be low, and hence the value of fault current will be severely reduced. In practice, approximately 95% of the stator winding can be protected. For faults in the last 5% of the winding, the earth fault current is so low that it cannot be detected by this type of earth fault protection. In most applications this limitation is accepted as the chances of an earth fault occurring in the last 5% of the winding, where the voltage to earth is low, is small.

The percentage of winding covered by the earth fault protection can be calculated as shown below, with reference to Figure 35.

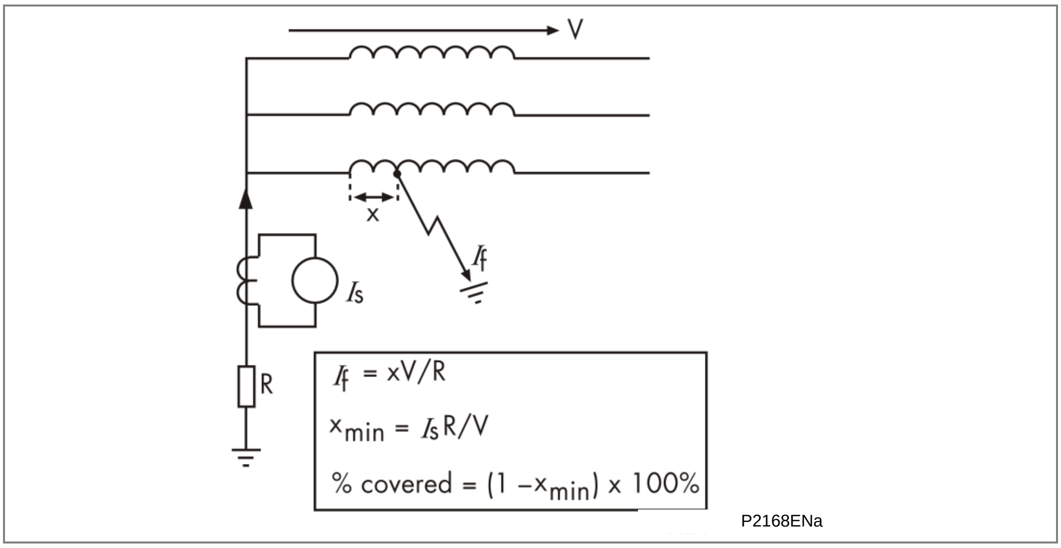


Figure 35 - Effective coverage of stator earth fault protection

A two stage non-directional earth fault element is provided. The first stage has an inverse time or definite time delay characteristic and can incorporate a reset time delay to improve detection of intermittent faults. The second stage has a definite time characteristic that can be set to 0 s to provide instantaneous operation.

Where impedance or distribution transformer earthing is used the second stage of protection may be used to detect flashover of the earthing impedance. The second stage may also be used to provide instantaneous protection where grading with system protection is not required. See setting guidelines for more details.

Each stage of protection can be blocked by energizing the relevant DDB signal via the PSL (DDB 544, DDB 545). This allows the earth fault protection to be integrated into busbar protection schemes as shown in section 2.34, or can be used to improve grading with downstream devices.

The Stator Earth Fault element is powered from the In CT input on the relay. This input should be supplied from a CT fitted into the generator earth path so that the element provides earth fault protection for the generator and back-up protection for system faults. Alternatively, the element may be supplied from a CT fitted on the secondary side of a distribution transformer earthing system.

2.17.1 Setting Guidelines for Stator Earth Fault Protection

The first stage of earth fault protection can be selected by setting IN>1 Function to any of the inverse or DT settings. The first stage is disabled if IN>1 Function is set to Disabled.

The second stage of earth fault protection can be selected by setting IN>2 Function to Enabled. The second stage is disabled if IN>2 Function is set to Disabled.

For a directly connected machine the stator earth fault protection must co-ordinate with any downstream earth fault protections. The first stage current setting, IN>1 Current, should typically be set to less than 33% of the machine earth fault contribution or full load current, whichever is lower. The time delay characteristic of the element (selected via IN>1 Function and IN>1 Time Delay, IN>1 TMS or IN>1 Time Dial) should be set to time grade with any downstream earth fault protection. Where the element is required to protect 95% of the generator winding a current setting of 5% of the limited earth fault current should be used.

Where impedance or distribution transformer earthing is used the second stage may be used to detect flashover of the earthing impedance. In such a case the second stage current setting, IN>2 Current, could be set to approximately 150% of the limited earth fault current and the time delay, IN>2 Time Delay, would be set to 0 s, to provide instantaneous operation.

For a machine connected to the system via a step-up transformer there is no need to grade the stator earth fault element with system earth fault protections. In this case the first stage should be set to 5% of the limited earth fault current to provide protection for 95% of the machine winding. The time delay characteristic of the stage should grade with VT fuses for VT earth faults. A transient generator earth fault current may also occur for a HV earth fault due to transformer inter-winding capacitance. Correct grading under these conditions can be provided by using a definite time delay of between 0.5 - 3 s. Experience has shown that it is possible to apply an instantaneous stator earth fault element on a indirectly connected machine if a current setting of ≥10% of the limited earth fault current is used. Therefore the second stage can be set to give this instantaneous protection.

2.18 Residual Overvoltage/Neutral Voltage Displacement Protection Function (59N)

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.

Alternatively, if the system is impedance or distribution transformer earthed, the neutral displacement voltage can be measured directly in the earth path via a single-phase VT. This type of protection can be used to provide earth fault protection irrespective of whether the generator is earthed or not, and irrespective of the form of earthing and earth fault current level. For faults close to the generator neutral the resulting residual voltage will be small. Therefore, as with stator earth fault protection, only 95% of the stator winding can be reliably protected.

Note	*Where residual overvoltage protection is applied to a directly connected generator, such a voltage will be generated for an earth fault occurring anywhere on that section of the system and so the NVD protection must coordinate with other earth fault protections.*

The neutral voltage displacement protection function of the P342/P343 relays consist of two stages of derived and two stages of measured neutral overvoltage protection with adjustable time delays. The P344/P345 has an additional two stages of measured neutral overvoltage protection as it has a dedicated second neutral voltage input.

Two stages are included for the derived and measured elements 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.

2.18.1 Setting Guidelines for Residual Overvoltage/Neutral Voltage Displacement Protection

Stage 1 may be selected as either IDMT (inverse time operating characteristic), DT (definite time operating characteristic) or Disabled, within the VN>1 Function cell. Stage 2 operates with a definite time characteristic and is Enabled/Disabled in the VN>2 Status cell. The time delay. (VN>1 TMS - for IDMT curve; V>1 Time Delay, V>2 Time Delay - for definite time) should be selected in accordance with normal relay co-ordination procedures to ensure correct discrimination for system faults.

The residual overvoltage protection can be set to operate from the voltage measured at the VN (P342/P343), VN1 and VN2 (P344/P345) input VT terminals using VN>3/4 (P342/P343), VN>3/4 and VN>5/6 (P344/P345) protection elements or the residual voltage derived from the phase-neutral voltage inputs as selected using the VN>1/2 protection elements.

For a directly connected machine the neutral voltage displacement protection must coordinate with any downstream earth fault protections. To ensure coordination the voltage setting of the neutral voltage displacement protection function should be set higher than the effective setting of current operated earth fault protection in the same earth fault zone. The effective voltage setting of a current operated earth fault protection may be established from the following equations:

Veff = (Ipoc x Ze) / (1/3 x V1/V2) for an open delta VT

Veff = (Ipoc x Ze) / (V1/V2) for a single-phase star point VT

Where:

Veff = Effective voltage setting of current operated protection

Ipoc = Primary operating current of current operated protection

Ze = Earthing impedance

V1/V2 = VT turns ratio

It must also be ensured that the voltage setting of the element is set above any standing level of residual voltage that is present on the system. A typical setting for residual overvoltage protection is 5 V.

The second stage of protection can be used as an alarm stage on unearthed or very high impedance earthed systems where the system can be operated for an appreciable time under an earth fault condition.

Where the generator is connected to the system via a transformer, co-ordination with system earth fault protections is not required. In these applications the NVD voltage setting should typically be set to 5% of rated voltage. This will provide protection for 95% of the stator winding.

2.19 Sensitive Earth Fault Protection Function (50N/51N/67N/67W)

If a generator is earthed through a high impedance, or is subject to high ground fault resistance, the earth fault 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 sensitive earth fault element is provided within the P34x & P391 relay for this purpose, this has a dedicated CT input allowing very low current setting thresholds to be used.

An alternative use for the sensitive earth fault input is on a multiple earthed system where it is advantageous to apply a directional earth fault relay at the machine terminals. The directional relay, operating for current flowing into the machine, will be stable for external faults but can operate quickly for generator faults when fault current is fed from the system.

Where several machines are connected in parallel, it is common for only one machine to be earthed at any time. This prevents the flow of third harmonic currents that could overheat the machine. This may be the only earth connection for this part of the system. Non-directional earth fault protection could be applied at the terminals of the unearthed machines in such cases since an unearthed generator cannot source earth fault current. However, as any of the machines can be earthed, it is prudent to apply directional protection at the terminals of all the machines. There is also a risk that transient spill current can cause operation of a non-directional, terminal fed, earth fault relay for an external phase fault, hence directional elements have an added degree of security. When applied in this way the directional earth fault elements will operate for faults on the unearthed machines but not the earthed machine. Therefore additional stator earth fault or residual overvoltage/NVD protection should be used to protect the earthed machine. Such a scheme will provide stable, fast, earth fault protection for all machines, no matter which generator is earthed.

A single stage definite time sensitive earth fault protection element is provided in the P34x & P391 relay, this element can be set to operate with a directional characteristic when required. Where Petersen Coil earthing is used, users may wish to use Wattmetric Directional Earth Fault protection or an Icosϕ characteristic. Settings to enable the element to operate as a wattmetric element are also provided. For insulated earth applications, it is common to use the Isinϕ characteristic. See the P140 technical guide P14x/EN T for more details on the application of directional earth fault protection on insulated and Petersen coil systems.

2.19.1 Setting Guidelines for Sensitive Earth Fault Protection

The operating function of the sensitive earth fault protection can be selected by setting SEF/REF Options cell. The SEF protection is selected by setting ISEF>1 Function to Enabled. To provide sensitive earth fault or sensitive directional earth fault protection the SEF/REF Options cell should be set to SEF. For SEF cosϕ and SEF sinϕ earth fault protection SEF/REF Options cell should be set to SEF Cos (PHI) or SEF Sin (PHI). The SEF cosϕ and SEF sinϕ options are not available with low impedance REF protection. For wattmetric earth fault protection SEF/REF Options cell should be set to Wattmetric. The other options for SEF/REF Options relate to restricted earth fault protection, for more details see section 2.20.

The directionality of the element is selected in the ISEF> Direction setting. If ISEF> Direction is set to Directional Fwd the element will operate with a directional characteristic and will operate when current flows in the forward direction, i.e. when current flows into the machine with the relay connected as shown in the standard relay connection diagram. If ISEF> Direction is set to Directional Rev the element will operate with a directional characteristic and will operate when current flows in the opposite direction, i.e. current flow out of the machine into the system. If ISEF> Direction is set to Non-Directional the element will operate as a simple overcurrent element. If either of the directional options are chosen additional cells to select the characteristic angle of the directional characteristic and polarizing voltage threshold will become visible.

The operating current threshold of the Sensitive Earth Fault protection function, ISEF>1 Current, should be set to give a primary operating current down to 5% or less of the minimum earth fault current contribution to a generator terminal fault.

The directional element characteristic angle setting, ISEF> Char Angle, should be set to match as closely as possible the angle of zero sequence source impedance behind the relaying point. If this impedance is dominated by an earthing resistor, for example, the angle setting would be set to 0°. On insulated or very high impedance earthed systems the earth fault current measured by an SDEF element is predominantly capacitive hence the RCA should be set to –90°.

The polarizing voltage threshold setting, ISEF> VNpol Set, should be chosen to give a sensitivity equivalent to that of the operating current threshold. This current level can be translated into a residual voltage as described for the residual overvoltage protection in section 2.18.

When the element is set as a non-directional element the definite time delay setting ISEF>1 Delay should be set to coordinate with downstream devices that may operate for external earth faults. For an indirectly connected generator the SEF element should coordinate with the measurement VT fuses, to prevent operation for VT faults. For directional applications when the element is fed from the residual connection of the phase CTs a short time delay is desirable to ensure stability for external earth faults or phase/phase faults.

A time delay of 0.5 s will be sufficient to provide stability in the majority of applications. Where a dedicated core balance CT is used for directional applications an instantaneous setting may be used.

2.20 Restricted Earth Fault Protection (64)

Earth faults occurring on a machine winding or terminal may be of limited magnitude, either due to the impedance present in the earth path or by the percentage of stator winding that is involved in the fault. As stated in section 2.16, it is common to apply stator earth fault protection fed from a single CT in the machine earth connection - this can provide time delayed protection for a stator winding or terminal fault. On larger machines, typically >2 MW, where phase CTs can be fitted to both neutral end and terminal ends of the stator winding, phase differential protection may be fitted. For small machines, however, only one set of phase CTs may be available making phase differential protection impractical. For smaller generators earth fault differential protection can be applied to provide instantaneous tripping for any stator or terminal earth fault. In application the operating zone of earth fault differential protection is restricted to faults within the boundaries of the CTs supplying the relay, hence this type of element is referred to as restricted earth fault protection.

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; percentage 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 P34x & P391 relays may be configured to operate as either a high impedance differential or a low impedance biased differential element.

In the P343/P344/P345 the 3 phase current source for the low impedance REF can be selected using the IREF> CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting. In the standard connection diagrams in the installation chapter, *P34x & P391/EN IN*, IA-1/IB-1/IC-1 is connected to the neutral side CTs and IA-2/IB-2/IC-2 is connected to the terminal side CTs. By selecting the terminal side CTs for the 3-phase currents the low impedance REF protection can be used to provide REF protection of the transformer LV star winding for generator-transformer applications or for REF protection of the generator.

Note	*CT requirements for REF protection are included in section 4.*

2.20.1.1 Setting Guidelines for Low Impedance Biased REF Protection

To select low impedance biased REF protection SEF/REF Option should be selected to Lo Z REF. If REF protection is required to operate alongside sensitive earth fault protection, SEF/REF Option should be selected to Lo Z REF + SEF or Lo Z REF + Wattmet (if Wattmetric earth fault protection is required).

Two bias settings are provided in the REF characteristic of the P34x. The IREF> k1 level of bias is applied up to through currents of IREF> Is2, which is normally set to the rated current of the machine. IREF> k1 should normally be set to 0% to give optimum sensitivity for internal faults. However, if any differential spill current is present under normal conditions due to CT mismatch, then IREF> k1 may be increased accordingly, to compensate.

IREF> k2 bias is applied for through currents above IREF> Is2 and may typically be set to 150% to ensure adequate restraint for external faults.

The neutral current scaling factor which automatically compensates for differences between neutral and phase CT ratios relies on the relay having been programmed with the correct CT ratios. Ensure these CT ratios are entered into the relay, in the CT RATIOS menu, for the scheme to operate correctly.

The differential current setting IREF> Is1 should typically be set to 5% of the limited earth fault current level.

In the P343/P344/P345 select the terminal side CTs with the IREF> CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting to provide REF protection of the transformer LV star winding for generator-transformer applications or for REF protection of the generator. In the standard connection diagrams in the installation chapter, *P34x & P391/EN IN*, IA-1/IB-1/IC-1 is connected to the neutral side CTs and IA-2/IB-2/IC-2 is connected to the terminal side CTs.

2.20.1.2 Setting Guidelines for High Impedance REF Protection

From the Sens E/F Option cell, Hi Z REF must be selected to enable High Impedance REF 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> Is) 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.

$$I_e < \frac{1}{n} \times \left(\frac{I_{op}}{\text{CT ratio}} - \text{Gen diff REF} > \text{Is1} \right)$$

2. To determine the maximum relay current setting to achieve a specific primary operating current with a given current transformer magnetizing current.

$$\text{IREF Is1} < \left(\frac{I_{op}}{\text{CT ratio}} - nI_e \right)$$

3. To express the protection primary operating current for a particular relay operating current and with a particular level of magnetizing current.

$$I_{op} = (\text{CT ratio}) \times (\text{IREF} > \text{Is1} + nI_e)$$

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.

$$R_{ST} = \frac{Vs}{\text{IREF} > \text{Is1}} = \frac{I_F (R_{CT} + 2R_L)}{\text{IREF} > \text{Is1}}$$

Note	*The above equation assumes negligible relay impedance.*

The stabilizing resistor supplied is continuously adjustable up to its maximum declared resistance.

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 could 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. This prospective voltage will be a function of maximum internal fault secondary current, the current transformer ratio, the current transformer secondary winding resistance, the current transformer lead resistance to the common point, the relay lead resistance and the stabilizing resistor value.

$$Vp = 2\sqrt{2 V_k (V_f - V_k)}$$

$$V_f = I'f (RCT + 2RL + RST)$$

Where:

V_p = Peak voltage developed by the CT under internal fault conditions

V_k = Current transformer knee-point 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 0.52x 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 non-linear resistor ("Metrosil") is not sinusoidal but appreciably distorted.

For satisfactory application of a non-linear resistor ("Metrosil"), its characteristic should be such that it complies with the following requirements:

- 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 1A current transformers and approximately 100 mA rms for 5A current transformers.
- 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 500 V 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.

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 less than 30 mA rms
- At the maximum secondary internal fault current the Metrosil unit should limit the voltage to 1500 V rms if possible.

The Metrosil units normally recommended for use with 1Amp CTs are shown in Table 7.

Relay voltage setting	Nominal characteristic		Recommended Metrosil type	
	C	β	Single pole relay	Triple pole relay
Up to 125 V rms	450	0.25	600A/S1/S256	600A/S3/1/S802

Relay voltage setting	Nominal characteristic		Recommended Metrosil type	
	C	β	Single pole relay	Triple pole relay
125 to 300 V rms	900	0.25	600A/S1/S1088	600A/S3/1/S1195

Table 7 - Recommended Metrosil types for 1 A CTs

Note	*Single pole Metrosil units are normally supplied without mounting brackets unless otherwise specified by the customer*

Metrosil Units for Relays with a 5 Amp CT

These Metrosil units have been designed to comply with the following requirements:

- At the relay voltage setting, the Metrosil current should less than 100 mA rms (the actual maximum currents passed by the units shown below their type description).
- At the maximum secondary internal fault current the Metrosil unit should limit the voltage to 1500 V rms for 0.25secs. 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 *, **, ***).

The Metrosil units normally recommended for use with 5 Amp CTs and single pole relays are shown in Table 8.

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
50A	600A/S1/S1213 C = 540/640 35 mA rms	600A/S1/S1214 C = 670/800 40 mA rms	600A/S1/S1214 C =670/800 50 mA rms	600A/S1/S1223 C = 740/870* 50 mA rms
100A	600A/S2/P/S1217 C = 470/540 70 mA rms	600A/S2/P/S1215 C = 570/670 75 mA rms	600A/S2/P/S1215 C = 570/670 100 mA rms	600A/S2/P/S1196 C =620/740* 100 mA rms
150A	600A/S3/P/S1219 C = 430/500 100 mA rms	600A/S3/P/S1220 C = 520/620 100 mA rms	600A/S3/P/S1221 C = 570/670** 100 mA rms	600A/S3/P/S1222 C =620/740*** 100 mA rms
Note	**2400 V peak*	***2200 V peak*	****2600 V peak*	

Table 8 - Recommended Metrosil types for 5 A CTs

In some situations single disc assemblies may be acceptable, contact Schneider Electric for detailed applications.

- 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 for each other. To order these units please specify "Triple Pole Metrosil Type", followed by the single-pole type reference.
- Metrosil units for higher relay voltage settings and fault currents can be supplied if required.

For further advice and guidance on selecting METROSILS please contact the Applications department at Schneider Electric.

2.21 100% Stator Earth Fault Protection (3rd Harmonic Method) (27TN/59TN)

As stated in sections 2.16 and 2.18, standard residual current or residual overvoltage protection elements can provide earth fault protection for 95% of the generator stator winding.

Earth faults in the final 5% of the winding will result in such a low fault current or such a small imbalance in voltage that conventional protection cannot be relied on to detect the fault. In most applications this limitation is accepted due to the low probability of a fault occurring in the 5% of the stator winding closest to the star point, where the voltage to earth is lowest. However, for large generators 100% stator earth fault protection is commonly specified to cover all winding earth faults. Faults close to the star point can occur as a consequence of mechanical damage such as creepage of the conductors and loosening of bolts.

Most generators will produce third harmonic voltage to some degree due to non-linearities in the magnetic circuits of the generator design. Under normal operating conditions the distribution of the third harmonic voltage along the stator windings corresponds to Figure 36a. The maxima occur at the star point N and the terminal T. The values increase with generator load. For a stator earth fault at the star point, Figure 36b, the amplitude of the third harmonic in the voltage at the terminals is approximately doubled both when the generator is off load prior the fault (U'TE) and when it is fully loaded (U"TE). The same third harmonic values can be measured in the star point voltages U'NE and U"NE for an earth fault at the generator terminals, Figure 36c.

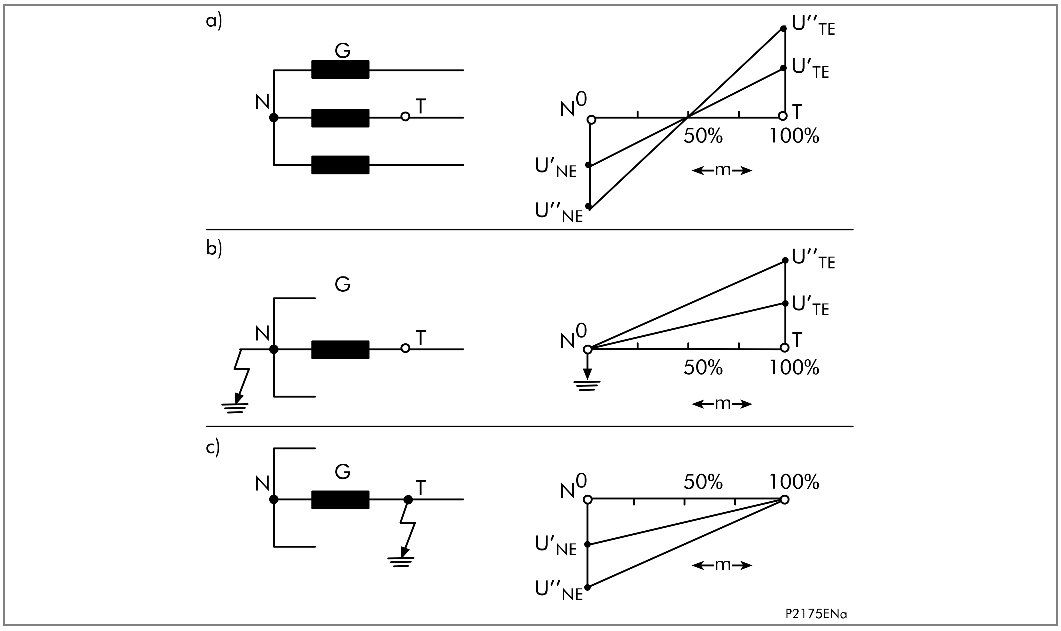


Figure 36 - Distribution of the 3rd harmonic component along the stator winding of a large generator

Figure 36 shows (a) normal operation, (b) stator earth fault at the star point (c), stator earth fault at the terminals.

m = relative number of turns

To detect faults in the last 5% of the generator winding, the P343/P344/P345 relay is provided with a third harmonic undervoltage and overvoltage element. These, together with the residual overvoltage or stator earth fault protection elements, will provide protection for faults over the complete winding.

The third harmonic neutral under voltage element is applicable when the neutral voltage measurement is available at the neutral end of the generator.

It is supervised by a three-phase under voltage element, which inhibits the protection when all the phase-phase voltages at the generator terminal are below the threshold, to prevent operation when the machine is dead, interlocking may also be required to prevent false operation during certain conditions. For example, some machines do not produce substantial third harmonic voltage until they are loaded. In this case, the power supervision elements (active, reactive and apparent power) could be used to detect load to prevent false tripping under no load conditions. These power thresholds can be individually enabled and disabled and the setting range is from 2 - 100%Pn.

For applications where the neutral voltage measurement can only be obtained at the generator terminals, from a broken delta VT for example, the undervoltage technique cannot be applied. Therefore the third harmonic neutral overvoltage element can be used for this application. The blocking features of the undervoltage and power elements are not required for the 3rd harmonic neutral over voltage element.

Note	*The relay can only select 3rd harmonic neutral undervoltage or 3rd harmonic neutral over voltage, but not both.*

A normal level of third harmonic voltage of 1% is sufficient to ensure that third harmonic undervoltage or overvoltage and residual overvoltage protection functions will overlap hence providing 100% coverage for earth faults on the stator winding. In general, third harmonic undervoltage protection alone can provide coverage for faults on 30% of the generator winding.

The 3rd harmonic undervoltage element operates from the same input as the neutral voltage displacement protection (VN1 input for P343/P344/P345) and must be supplied from a VT connected in the generator earth connection as shown in Figure 37. The 3rd harmonic overvoltage element operates from the neutral voltage measurement at the generator terminals, via an open-delta VT, for example as shown in Figure 37. For applications where parallel machines are directly connected to the busbars discrimination of an earth fault between the machines usually can not be achieved. For applications where machines are connected to the busbars via a delta/star transformer the delta winding blocks the 3rd harmonic currents from other machines so correct discrimination can be achieved for earth faults.

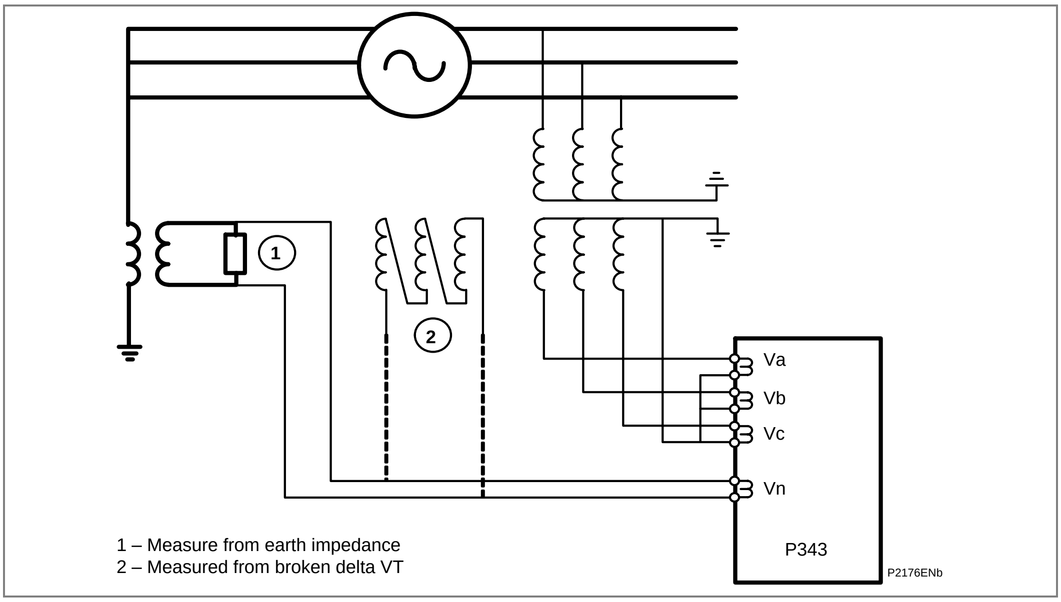


Figure 37 - Connection for 3rd harmonic undervoltage and overvoltage for 100% stator earth fault protection

2.21.1 Setting Guidelines for 100% Stator Earth Fault Protection

The 100% stator earth fault protection element can be selected by setting the 100% St EF Status cell to Enabled.

The third harmonic undervoltage threshold, 100% St EF VN3H<, must be set below the level of third harmonic voltage present under normal conditions. This voltage can be determined by viewing the VN 3rd Harmonic cell in the MEASUREMENTS 3 menu. A typical value for this threshold could be 0.5 V.

The third harmonic overvoltage threshold, 100% St EF VN3H>, must be set above the level of third harmonic voltage present under normal conditions. This voltage can be determined by viewing the VN 3rd Harmonic cell in the MEASUREMENTS 3 menu. A typical value for this threshold could be 1 V.

A time delay for these elements can be set in the VN3H< Delay and VN3H> Delay cells.

The terminal voltage interlock threshold, used to prevent operation of the element when the machine is not running, 100% St EF V<Inh, should typically be set to 80% of machine rated voltage.

The power interlock thresholds, used to prevent operation of the element until there is sufficient load current, P<Inhibit set, Q<Inhibit set, S<Inhibit, should be enabled if required to prevent operation under no load conditions. One or more of the thresholds can be used as an interlock. They should be set during commissioning by increasing the load current until the 3rd harmonic undervoltage element is reset and setting the power thresholds above the measured power values. The power values can be determined by viewing the three-phase Watts, three-phase Vars, three-phase VA cells in the MEASUREMENTS 2 menu.

Note	*Other earth fault protection (residual overvoltage or current operated stator earth fault protection) must also be enabled to provide coverage for earth faults across the complete stator winding.*

2.22 100% Stator Earth Fault Protection (Low Frequency Injection Method) (64S)

The 100% stator earth fault protection using a low frequency injection technique detects earth faults in the entire winding, including the generator neutral point. If an earth fault in the generator starpoint or close to the starpoint is not detected the generator is effectively running with a low impedance earth bypassing the high impedance earth typically used on large machines. A second earth fault can then cause a very high current to flow which can cause a lot of damage to the machine. This is why 100% stator earth fault protection is a common requirement for large machines.

The low frequency injection technique can be used to provide protection for 100% of the stator winding compared to only 20-30% of the winding using the 3rd harmonic technique. Also, the low frequency injection technique provides protection when the machine is stopped and running and also when the machine is running up and down. The 3rd harmonic technique has to be blocked or is not operational when the machine is stopped and when the machine is running up and down. Also, some machines only produce a low level of 3rd harmonic voltage (<1% Vn) and for these machines the 3rd harmonic method of 100% stator earth fault protection can not be used. So in these applications only the low frequency injection method can provide 100% stator earth fault protection.

100% stator earth fault protection can be provided by injecting an external low frequency alternating voltage into the starpoint or the terminals of the machine. Under normal healthy conditions only a very small current flows via the stator earth capacitance due to the high impedance of this path at low frequencies ($X_c = 1/2\pi fc$). In the event of an earth fault the measured current increases due to the smaller impedance of the earth fault path. From the injected voltage and the fault current the relay can determine the fault resistance. The protection can also detect earth faults at the generator terminals including connected components such as voltage transformers.

A loading device with a low frequency generator is required for implementation. The output of the low frequency signal generator (approx 25 V) is connected via a bandpass filter in parallel with a loading resistor to a neutral transformer at the generator starpoint or an earthing (broken delta) transformer at the terminals of the generator.

The loading resistor is connected in parallel with the low frequency generator to generate a defined neutral current in normal healthy conditions.

The voltage to be injected into the generator starpoint depends on the driving 20 Hz voltage (voltage divider, load resistor and bandpass), and on the transformation ratio of the neutral or earthing transformer. To prevent the secondary load resistance from becoming too small (it should be > 0.5 Ω, where possible to minimize measurement errors) a high secondary voltage, such as 500 V, should be chosen for the neutral or earthing transformer.

Note	*The voltage withstand of the bandpass filter voltage divider is 550 V ac for ≤ 30s*

It is important that the earthing transformer never becomes saturated otherwise ferroresonance may occur. It is sufficient that the transformer knee point voltage be equal to the generator rated line voltage. The low frequency voltage is fed to the relay via a voltage divider and the low frequency measuring current is fed via a miniature current transformer. All interference deviating from the nominal low frequency signal is filtered out.

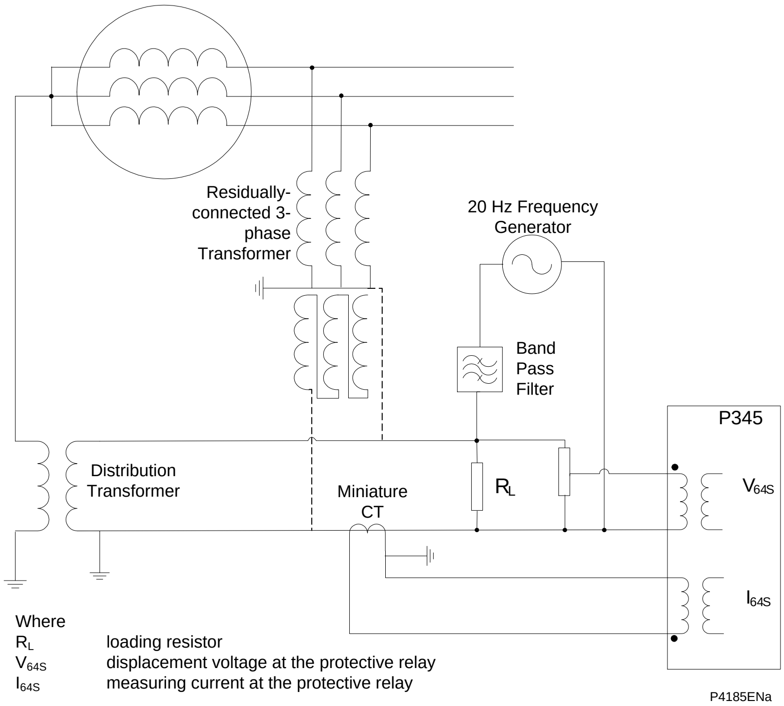
The 100% stator earth fault protection can also be applied with a primary loading resistor. The 20 Hz voltage is connected via a voltage transformer and the neutral starpoint current is directly measured via a CT, see section 2.22.2.3.

From the measured current and voltage vectors the complex impedance can be calculated and from this the ohmic resistance is determined. This eliminates disturbances caused by the stator earth capacitance and ensures high sensitivity. The relay algorithm can take into account a transfer resistance 64S Series R, that may be present at the neutral or earthing voltage transformer. An example of the series resistance is the total leakage resistance of the earthing or neutral transformer, through which the injected voltage is applied to the generator neutral. The algorithm can also account for parallel resistance, 64S Parallel G (G = 1/R), such as an additional earthing transformer connected on the LV side of the step-up transformer. Other error factors can be taken into account by the angle error compensation, 64S Angle Comp.

The relay includes a 20 Hz overcurrent element which can be used as a back-up to the 20 Hz under resistance protection. The overcurrent element is not as sensitive as the under resistance elements as it does not include any transfer resistance compensation or any compensation for capacitance affects.

In addition to the determination of the earth resistance, the relay also includes 95% stator earth fault protection as a back-up to the 100% stator earth fault protection. The neutral voltage protection from the measured earthing/neutral transformer or calculated neutral voltage from the 3 phase voltage input can be used to provide 95% stator earth fault protection and is active during the run-up and run-down of the generator.

The 100% stator earth fault protection includes 2 stages of under resistance protection for alarm and trip and an overcurrent protection stage, with each stage having a definite time delay setting. The protection includes a supervision element to evaluate a failure of the low frequency generator or the low frequency connection.



Where

R_L	loading resistor
V_{64S}	displacement voltage at the protective relay
I_{64S}	measuring current at the protective relay

Figure 38 - 100% stator earth fault protection with earthing (broken delta) transformer or neutral transformer

2.22.1 Setting Guidelines for 100% Stator Earth Fault Protection

The 100% stator earth fault protection element can be selected by setting the 64S 100%St EF cell to Enabled.

The 64S R Factor is set as described in section 2.22.2 – Setting Calculation for the R Factor.

The under resistance alarm threshold, 64S Alarm Set, must be set below the level of resistance present under normal conditions. This resistance can be determined by viewing the 64S R cell in the MEASUREMENTS 3 menu. A typical value for the primary fault resistance alarm setting is between 3-8 kΩ .

The under resistance trip threshold, 64S R<2 Trip Set, must be set below the level of resistance present under normal conditions. This resistance can be determined by viewing the 64S R cell in the MEASUREMENTS 3 menu. A typical value for the primary fault resistance trip setting is between 1-2 kΩ .

The overcurrent trip threshold, 64S I>1 Trip Set, must be set above the 20 Hz level of current present under normal conditions. This secondary current can be determined by viewing the 64S I Magnitude cell in the MEASUREMENTS 3 menu.

The P345's 64S protection has a very powerful band pass filter tuned to 20 Hz. The band pass filter is designed with an attenuation of at least -80 db for frequencies less than 15 Hz and greater than 25 Hz. -80 db is equivalent to a noise rejection capability with a noise-to-signal ratio of 10000 to 1. However, it is not possible for the filter to reject all the 'noises' around 20 Hz. When the power system frequency is at 20 Hz, the relay will not be able to distinguish the power system frequency signal and the injected signal.

Under no fault conditions, the influence of the 20 Hz power system components is practically negligible. So there is no risk of relay mal-operation under system frequency conditions, from 0 Hz to 70 Hz. The current measured will effectively be the capacitive current plus the current through the parallel resistance. The 64S I>1 should be set higher than this quiescent current.

For earth faults occurring 0 – 15 Hz and 25 - 70 Hz at any point on the stator windings both the under resistance (64S R<) and overcurrent protection (64S I>) work correctly under these power system frequency conditions due to the relay filtering. The power system frequency components will be removed by the band pass filter and will have no influence on the protection measurements.

The influence of the power system signals depend on the position of the fault. At the star point, the influence is negligible. Therefore both the under resistance (64S R<) and overcurrent protection (64S I>) work correctly under the complete range of power system frequencies from 0 to 70 Hz when the faults occur at the star-point.

For faults not at the star point where the power system frequency signals are at or close to 20 Hz the power system 20 Hz signals become more and more dominant as the fault position moves towards the terminal of the generator. For these faults there is a possibility the R< elements can overreach. In most cases the current is 180° out of phase with the voltage.

The 64S current (I64S(P345)) under fault conditions consists of two components, the 20 Hz current component from the 20 Hz injection system, (I64S(20)) and the 20 Hz current component produced by the neutral displacement voltage, (I64S(G)). At or around 20 Hz, the I64S(G) cannot be filtered off and therefore contributes in magnitude to the I64S(P345), which improves the fault detection capability of the 64S I>1 protection function.

Therefore the 64S I> element can be used to provide back-up protection for faults that occur when the machine is running at 20 Hz. The I64S I>1 Trip can be set as a back-up element 15-25 Hz to the 64S R<1/R<2 elements by setting a longer trip time.

If required the R<1 and R<2 protection can be blocked at around 20 Hz. The 64S F Band Block (operates when the measured frequency is in the range 15-25 Hz) and can be used to inhibit/block the 64S R<1, R<2 protection.

A time delay for these elements can be set in the 64S R<1 Alm Dly, 64S R<2 Trip Dly and 64S I>1 Trip Dly cells. The default time delays provide typical values.

If the 20 Hz voltage drops below the voltage supervision threshold, 64S V<1 Set and the 20 Hz current remains below the current supervision threshold, 64S I< Set, there must be a problem with the 20 Hz connection. The default settings for 64S Supervision element, 64S V<1 Set (1 V) and 64S I<1 Set (10 mA) will be adequate for most applications. Where the loading resistor is less than 1 Ω, the supervision voltage threshold, 64S V<1 Set, must be reduced to 0.5 V, the supervision current threshold, 64S I<1 Set, can be left at 10 mA.

The Comp Angle setting is used to compensate the angle errors between the CT and earthing or neutral transformer. The setting can be found from primary testing.

The 64S Series R setting is used to account for the transfer resistance of the earthing or neutral voltage transformer. The default setting will be zero as the resistance of the voltage transformer is normally negligible. The resistance of the voltage transformer is not negligible if the low frequency voltage is fed to a primary side resistor via the voltage transformer. The setting can be estimated from calculation or from primary testing, see section 2.22.3.

In large power units with a generator CB, applications can be found where there is some additional loading equipment such as an earthing transformer on the low voltage side of the unit transformer to reduce the influence of zero sequence voltage when the generator CB is open. If the low frequency source is connected via the neutral transformer in the generator starpoint, when the generator CB is closed the protection measures the loading resistance on the unit transformer side which can be mistaken for an earth resistance.

The 64S Parallel G setting can be used to account for this additional parallel loading resistance. The default setting is 0, no additional loading resistor.

The neutral transformer-resistor at the star point should produce a resistive current equal to the capacitive current for an earth fault at rated voltage. The transformer, resistor and injection devices should withstand this condition for 10 seconds.

To prevent the secondary load resistance from becoming too small (it should be > 0.5 Ω where possible to minimize measurement errors) a high secondary voltage, such as 500 V, should be chosen for the neutral or earthing transformer. It is important that the earthing transformer never becomes saturated otherwise ferroresonance may occur. It is sufficient that the transformer knee point voltage be equal to the generator rated line voltage.

For a generator earthed with a primary resistor in the generator starpoint the lead resistance between the earthing transformer and the 20 Hz generator/bandpass filter can have a significant affect on the accuracy of the measured resistance by the relay. So if the 20 Hz generator and bandpass filter are mounted in the protection cubicle the loop lead resistance should ideally be kept below 0.5 Ω. If the 20 Hz generator and bandpass filter are mounted near the earthing transformer then this will keep the errors to a minimum. The lead resistance from the 20 Hz generator/banpass filter to the relay does not significantly affect the accuracy of the measured resistance.

For configurations with an earthing transformer and secondary loading resistance the lead resistance does not have a significant affect on the measured resistance by the relay.

Note	*Other earth fault protection functions such as residual overvoltage, earth fault or sensitive earth fault protection can be connected in parallel or series with to the 100% stator earth fault protection measurement inputs to provide back-up to the 100% stator earth fault protection.*

There will be some measurement of the injected 20 Hz injected and circulating current under normal healthy conditions on the VN1/2, I Sensitive and IN inputs used by these protection functions. For most applications under no fault conditions the 20 Hz voltage measured by the relay across the potential divider in the external filter box and loading resistor will small and be much less than 5% of rated voltage. The 20 Hz current under normal conditions should be very close to zero. So settings can be used to protect 95% of the stator winding in most applications. When commissioning the relay the level of 20 Hz neutral voltage or earth current should be checked to make sure it is less than half the setting value of any protection enabled to provide stability under normal operating conditions. There will be some fluctuation of the 20 Hz neutral voltage and earth current measured by the VN1/2, ISensitive and IN inputs under no fault conditions due to the 50/60 Hz frequency tracking of these inputs.

It is not recommended that the 3rd harmonic method of 100% stator earth fault protection is used in parallel with the 20 Hz injection method as there will be some measurement of the 20 Hz signal by the VN1 input used by the 3rd harmonic protection which could interfere with the correct operation of this sensitive function.

2.22.2 Setting Calculations for the R Factor

The R Factor calculation depends on the earthing arrangement of the generator and the location of the CT for the 64S current measurement.

2.22.2.1 Generator Earthed via Earthing Transformer

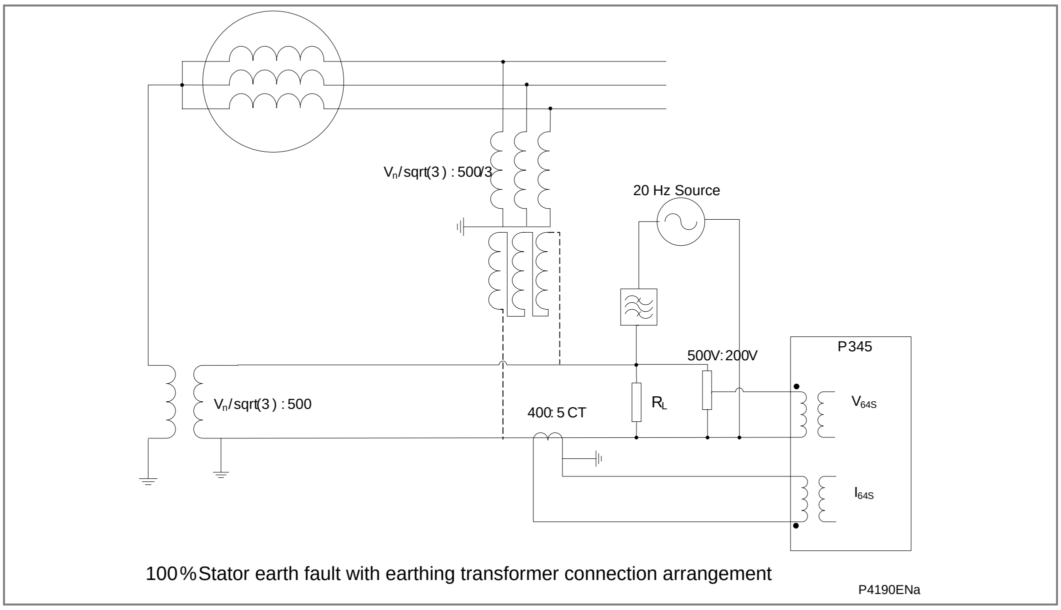


Figure 39 - 64S Connection for generators earthed via earthing transformer

With this arrangement, the injected voltage is applied through the secondary of the earthing transformer, which can either be a distribution transformer located at the neutral of the generator, or a three-phase, five limb voltage transformer with the secondary windings connected in broken delta. The current is also measured on the secondary transformer circuit. Therefore the relay is measuring the secondary fault resistance reflected through the earthing transformer. The primary fault resistance is related to the secondary resistance based on the following relationship:

$$\frac{R_{Primary}}{R_{Secondary}} = \frac{{V_{Primary}}^2}{{V_{Secondary}}^2}$$

It is also necessary to take into account the potential divider and the CT ratio. Therefore the primary resistance is calculated from the secondary resistance as follows:

$$R_{Primary} = \left(\frac{V_{Primary}}{V_{Secondary}}\right)^2 x \frac{V_{Divider\ Ratio}}{CT_{Ratio}} xR_{Secondary}$$

Where $\frac{V_{Primary}}{V_{Secondary}} = \frac{1}{3} \cdot \frac{\frac{V_{n\ Primary}}{\sqrt{3}}}{\frac{V_{n\ Secondary}}{3}}$ for the open-delta VT,

or, $\frac{V_{Primary}}{V_{Secondary}} = \frac{\frac{V_{n\ Primary}}{\sqrt{3}}}{V_{n\ Secondary}}$ for earthing transformer connected at the generator neutral.

Using the data shown in the diagram above as an example and assuming the 1A rated current input is used,

$$R_{Primary} = \left(\frac{V_n/\sqrt{3}}{500}\right)^2 x \frac{5}{2} x \frac{5}{400} xR_{Secondary}$$

Therefore,

$$R_{Factor} = \left(\frac{V_n/\sqrt{3}}{500}\right)^2 x \frac{5}{2} x \frac{5}{400}$$

2.22.2.2 Generator Earthed via Primary Resistor in Generator Starpoint

In some power systems the generators have a load resistor installed directly in the generator starpoint to reduce interference. The following diagram shows the connection of the 20 Hz generator, band pass filter and protection device. The 20 Hz voltage is injected into the generator starpoint via a powerful voltage transformer across the primary load resistor. In the presence of an earth fault, an earth current flows through the CT in the starpoint. The protection detects this current in addition to the 20 Hz voltage.

A two pole isolated voltage transformer must be used with low primary/secondary impedance. This applies for the 20 Hz frequency.

Primary voltage:	Vn,Generator /√3 (non-saturated up to Vn,Generator)
Secondary voltage:	500 V
Type and class:	3000 VA (for 20 s), class 0.5 (50 Hz or 60 Hz)

Primary – secondary impedance (ZPS) - ZPS <RL (ZPS <1000 Ω)

The CT is installed directly in the starpoint on the earth side, downstream of the load resistor.

Type:	15 VA 5P10 or 5P15
Rated secondary current:	5 A
Transformation Ratio:	1 (5A/5A)

As the transformation ratio is 1:1, a current transformer with a maximum number of ampere windings must be chosen.

Notes	*The linear range of the 100% stator earth fault input is up to 2 In. So if the earth fault current is limited to <2A then the 100% stator earth fault 1A input can be used. For earth fault currents 2-10A the relay 5A current input can be used.* *For the 5A inputs the 64S I Magnitude measurement in the Measurements 3 menu will show 5 times lower current than being injected. There is no CT ratio setting for the 100% stator earth fault current input, however the resistance measurement and 64SR<1/2 protection can be compensated by the 64S R Factor setting if the 5A input is used by multiplying the CT ratio by 5 in the formula for the R factor. If the 64S I>1 protection is used then the setting needs to be divided by a factor of 5 when using the 5A input.*

During the primary test the correction angle (64S Angle Comp) and the ohmic transfer resistance (R factor) of the voltage transformer must be determined and set.

The primary resistance and conversion factor for the resistance (R Factor) is calculated as follows:

$$R_{Primary} = VT_{Ratio} x \frac{V_{Divider\ Ratio}}{CT_{Ratio}} xR_{Secondary}$$

Where the VT ratio is

$$VT_{Ratio} = \frac{V_{n\ Primary}/\sqrt{3}}{V_{n\ Secondary}}$$

Using the data shown in the diagram as an example and assuming the 5A rated current input is used,

$$R_{Primary} = (\frac{V_n/\sqrt{3}}{500}) x \frac{5}{2x5} x R_{Secondary}$$

Therefore,

$$R_{Factor} = (\frac{V_n/\sqrt{3}}{500}) x \frac{5}{10}$$

Note	Due to the transfer resistance, there may not be an ideal transformation ratio of the voltage transformers. For this reason major deviations of the R Factor can occur. It is recommended to measure the transformation ratio with 20 Hz infeed when the machine is at standtill. This value should then be set, see Commissioning chapter, P34x/EN CM.

2.22.2.3 Setting Example with Generator Earthed via a Primary Resistor in Generator Starpoint

Voltage transformer rating:	10.5 kV/ √3/500 V, 3000 VA (for 20 s) class 0.5 (non-saturated up to Vn,Generator)
Voltage divider:	5:2
Current transformer:	5A/5A, 15 VA 5P10

The maximum primary earth fault current should be limited by the primary resistor to <10A, preferably 4-8A. If the primary earth fault current is limited to 5A then the primary load resistor is 1212 Ω.

Primary Load Resistor: $RL = \frac{10.5kV/\sqrt{3}}{5} = 1212\ \Omega$

The resistor as well as limiting the earth fault current to a suitable value prevents high transient overvoltages in the event of an arcing earth fault. For this reason the equivalent resistance in the stator circuit should not exceed the impedance at system frequency of the total summated capacitance of the three phases.

The linear range of the 100% stator earth fault input is up to 2 In. So if the earth fault current is limited to <2 A then the 100% stator earth fault 1A input can be used. For earth fault currents 2-10 A the relay 5 A current input can be used.

For the 5A inputs the 64S I Magnitude measurement in the Measurements 3 menu will show 5 times lower current than being injected. There is no CT ratio setting for the 100% stator earth fault current input, however the resistance measurement and 64SR<1/2 protection can be compensated by the 64S R Factor setting if the 5 A input is used by multiplying the CT ratio by 5 in the formula for the R factor. If the 64S I>1 protection is used then the setting needs to be divided by a factor of 5 when using the 5A input.

$$R_{Factor} = (\frac{10.5kV/\sqrt{3}}{500}) x \frac{5}{10} = 6.06$$

Voltage across the resistor during an earth fault is 10.5 kV/√3 = 6.1 kV and with field forcing may be 1.3 x 6.1 = 8 kV. So, 8 kV insulation will be satisfactory.

Typical trip and alarm settings for the 100% stator earth fault under resistance elements are:

Trip stage: primary 2 kΩ, secondary 330 Ω

Alarm stage: primary 4 kΩ, secondary 660 Ω

The IN current input used by the stator earth fault protection can also be connected to the earth CT to provide back-up stator earth fault protection for the generator.

To provide 95% stator earth fault protection

IN>1 Current = 0.05 x 5 = 0.25A

The VN1 voltage input used by the residual overvoltage/NVD protection can also be connected across the voltage divider to provide back-up stator earth fault protection for the generator. The voltage divider in the filter device can be used to provide a 5:1 divider to connect 100 V rated voltage to the VN1 input (Vn=100/120 V). Connections 1A1-1A2 on the filter provides a 5:1 divider to connect 100 V rated voltage to the VN1 input.

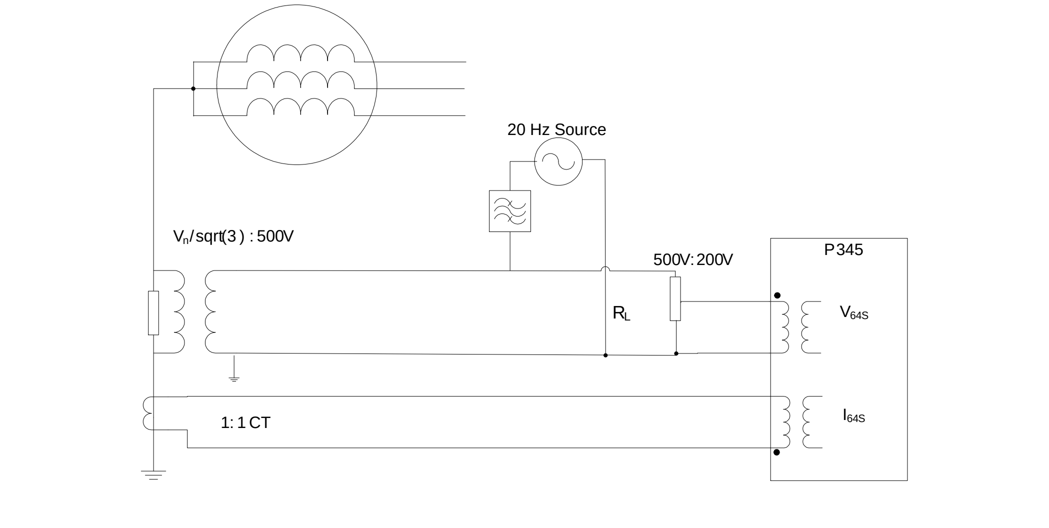


Figure 40 - 64S Connection for generators earthed via primary resistor

2.22.2.4 Setting Example with Generator Earthed via Earthing Transformer and Secondary Resistor at the Terminals of the Generator

Voltage transformer rating: 10.5 kV/√3 / 500/3 V (non-saturated up to $Vn,_{Generator}$)

Voltage divider: 5:2

Current transformer: 200/5

The transformation ratio of the miniature CT 400 A:5 A can been halved to 200:5A by passing the primary conductor twice through the transformer window.

The maximum primary earth fault current should be limited by the primary resistor to <10A, preferably 4-8A.

If the primary earth fault current is limited to 5A then primary load resistor is 1212 Ω.

The resistor as well as limiting the earth fault current to a suitable value prevents high transient overvoltages in the event of an arcing earth fault. For this reason the equivalent resistance in the stator circuit should not exceed the impedance at system frequency of the total summated capacitance of the three phases.

$$\frac{R_{Primary}}{R_{Secondary}} = \frac{V_{Primary}{}^2}{V_{Secondary}{}^2}$$

Secondary Load Resistor: RL = 1212 x $\left(\frac{3x\sqrt{3}x500}{10.5kVx3}\right)^2$ = 8.25 Ω

Voltage transformer secondary maximum earth fault current is 60A so with a 200:5A CT the secondary current at the relay is 1.5A.

The linear range of the 100% stator earth fault input is up to 2 In. So if the earth fault current is limited to <2 A then the 100% stator earth fault 1 A input can be used. For earth fault currents 2-10A the relay 5 A current input can be used.

$$R_{Factor} = \left(\frac{10.5kV/\sqrt{3}}{500}\right)^2 x \frac{5}{2} x \frac{5}{200} = 27.563$$

Assuming the transformer is from 3 single phase transformers

The transformer VA rating for 10 s per phase is 1.3 x 1/3 x 5 x 10500 / √3 = 13 KVA for 3 single phase transformers. The 1.3 accounts for an overvoltage factor from field forcing.

For a 20 s rating the VA rating is 9 KVA (13 x √10/√20)

For a 3-phase transformer the VA rating is 3 times higher, 27 KVA for 20 s.

Typical trip and alarm settings for the 100% stator earth fault under resistance elements are:

- Trip stage: primary 2 kΩ, secondary 66 Ω
- Alarm stage: primary 5 kΩ, secondary 165 Ω

The VN1 voltage input used by the residual overvoltage/NVD protection can also be connected across the voltage divider to provide back-up stator earth fault protection for the generator. The voltage divider in the filter device can be used to provide a 5:1 divider to connect 100 V rated voltage to the VN1 input which is typically rated for 100/120 V. Connections 1A1-1A2 on the filter provides a 5:1 divider to connect 100 V rated voltage to the VN1 input.

2.22.2.5 Setting Example with Generator Earthed via Earthing Transformer and Secondary Resistor at the Starpoint of the Generator

Voltage transformer rating: 10.5 kV/ √3/500 V (non-saturated up to $V_{n,\text{Generator}}$)

Voltage divider: 5:2

Current transformer: 200/5

The transformation ratio of the miniature CT 400 A:5 A can been halved to 200:5A by passing the primary conductor twice through the transformer window.

The maximum primary earth fault current should be limited by the primary resistor <10 A, preferably 4-8A.

If the primary earth fault current is limited to 5A then primary load resistor is 1212 Ω.

The resistor as well as limiting the earth fault current to a suitable value prevents high transient overvoltages in the event of an arcing earth fault. For this reason the equivalent resistance in the stator circuit should not exceed the impedance at system frequency of the total summated capacitance of the three phases.

$$\frac{R_{\text{Primary}}}{R_{\text{Secondary}}} = \frac{{V_{\text{Primary}}}^2}{{V_{\text{Secondary}}}^2}$$

Secondary Load Resistor: $RL = 1212 \text{ x } \left(\frac{\sqrt{3}x500}{10.5kV}\right)^2 = 8.25\ \Omega$

Voltage transformer secondary maximum earth fault current is 60 A so with a 200:5A CT the secondary current at the relay is 1.5A.

The linear range of the 100% stator earth fault input is up to 2 In. So if the earth fault current is limited to <2 A then the 100% stator earth fault 1A input can be used. For earth fault currents 2-10 A the relay 5 A current input can be used.

$$R_{\text{Factor}} = \left(\frac{10.5kV/\sqrt{3}}{500}\right)^2 x\frac{5}{2}x\frac{5}{200} = 27.563$$

The transformer VA rating for 10 s per phase is 1.3 x 5 x 10500 / √3 = 39 KVA. The 1.3 accounts for an overvoltage factor from field forcing.

For a 20 s rating the VA rating is 27 KVA (39 x √10/√20)

Typical trip and alarm settings for the 100% stator earth fault under resistance elements are:

- Trip stage: primary 2 kΩ, secondary 66 Ω
- Alarm stage: primary 5 kΩ, secondary 165 Ω

The VN1 voltage input used by the residual overvoltage/NVD protection can also be connected across the voltage divider to provide back-up stator earth fault protection for the generator.

The voltage divider in the filter device can be used to provide a 5:1 divider to connect 100 V rated voltage to the VN1 input which is typically rated for 100/120 V. Connections 1A1-1A2 on the filter provides a 5:1 divider to connect 100 V rated voltage to the VN1 input.

2.22.3 Methods to Establish the Series Settings for 64S

The series resistance 64S Series R is normally set as the total leakage resistance of the earthing transformer, through which the injection equipment is connected. It can either be set by calculations based on the transformer parameters, or by measurements during commissioning. The P345 measurements feature will be able to assist for the latter. See the Commissioning chapter, *P34x & P391/EN CM*, section 6.3.4.5 for the measurement method.

2.22.3.1 By Calculation

Given that the per unit quantity of the total leakage impedance of the transformer is $R_{pu}+jX_{pu}$, the transformer resistance parameters can be calculated as follows.

For the open-delta 3-phase voltage transformer connected at the generator terminal:

$$R_{Primary} = R_{PU} \times \frac{V_{n\,primary}(kV)^2}{Transformer\ kVA\ (3ph)}$$

For an earthing transformer connected to the generator neutral and for generator earthed via a resistor,

$$R_{Primary} = R_{PU} \times \frac{\left(V_{n\,primary}(kV)/\sqrt{3}\right)^2}{Transformer\ kVA}$$

2.23 Overfluxing Protection (24)

Overfluxing or overexcitation of a generator, or transformer connected to the terminals of a generator, can occur if the ratio of voltage to frequency exceeds certain limits. High voltage or low frequency, causing a rise in the V/Hz ratio, will produce high flux densities in the magnetic core of the machine or transformer. This could cause the core of the generator or transformer to saturate and stray flux to be induced in un-laminated components that have not been designed to carry flux. The resulting eddy currents in solid components (e.g. core bolts and clamps) and end of core laminations can cause rapid overheating and damage.

Overfluxing is most likely to occur during machine start up or shut down whilst the generator is not connected to the system. Failures in the automatic control of the excitation system, or errors in the manual control of the machine field circuit, could allow excessive voltage to be generated. It is also possible for overfluxing to occur during parallel operation when the generator has been synchronized with the local supply network. Sudden loss of load could cause an overvoltage condition, in such circumstances, if the generator excitation system does not respond correctly.

The P342/P343/P344/P345 relays provide a five stage overfluxing element. One stage can be set to operate with a definite time or inverse time delay (IDMT), this stage can be used to provide the protection trip output. There are also 3 other definite time stages which can be combined with the inverse time characteristic to create a combined multi-stage V/Hz trip operating characteristic using PSL. An inhibit signal is provided for the V/Hz>1 stage 1 only, which has the inverse time characteristic option. This allows a definite time stage to override a section of the inverse time characteristic if required. The inhibit has the effect of resetting the timer, the start signal and the trip signal. Figure 41, Figure 42, Figure 43 and Figure 44 give examples of the V/Hz settings and PSL logic to achieve a combined multi-stage V/Hz characteristic for a large and small machine.

There is also one definite time alarm stage that can be used to indicate unhealthy conditions before damage has occurred to the machine.

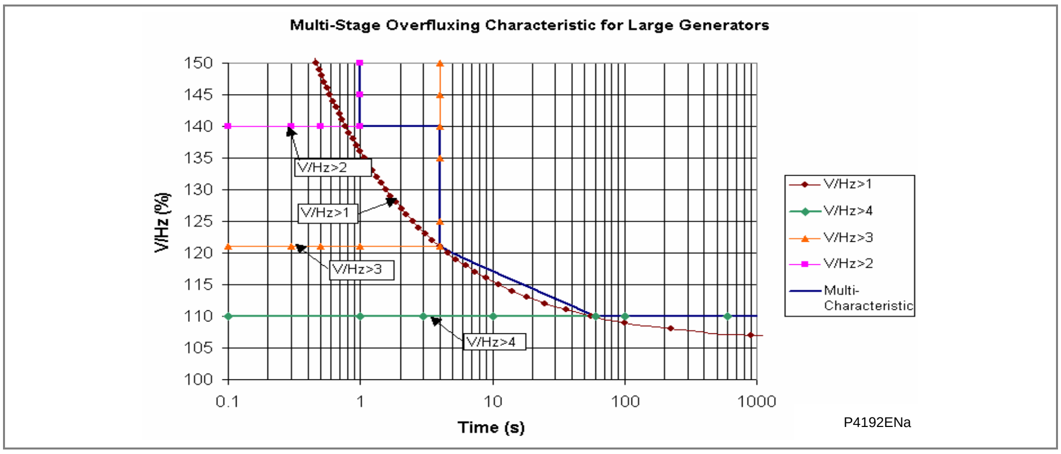


Figure 41 - Multi-stage overfluxing characteristic for large generators

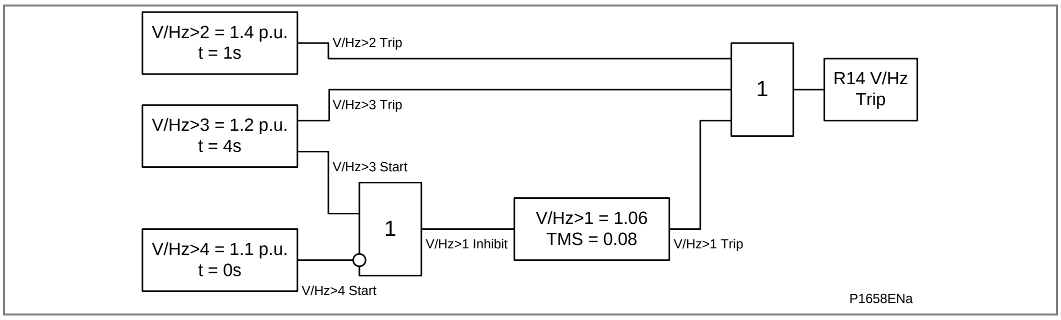


Figure 42 - Scheme logic for large generator multi-stage overfluxing characteristic

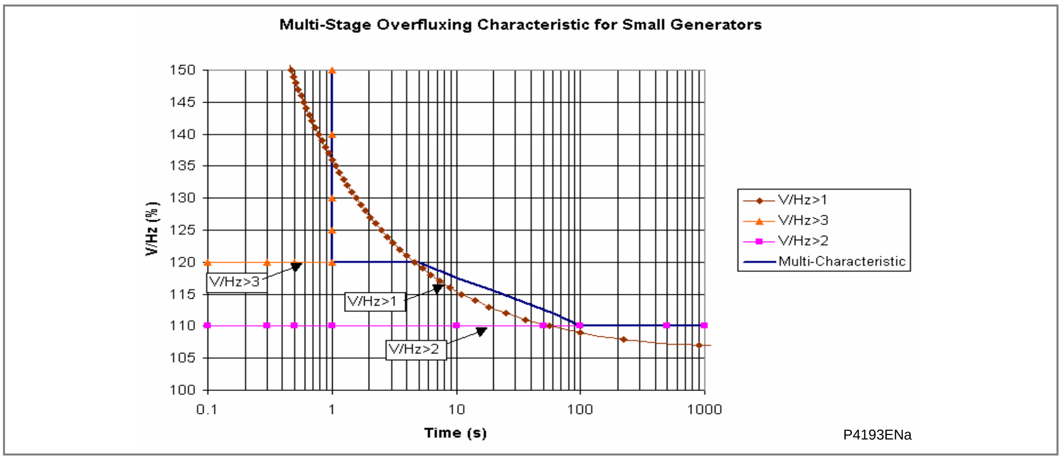


Figure 43 - Multi-stage overfluxing characteristic for small generators

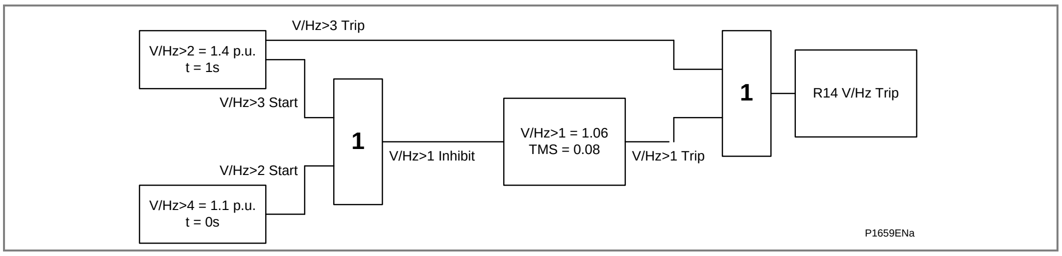


Figure 44 - Scheme logic for small generator multi-stage overfluxing characteristic

2.23.1 5th Harmonic Blocking

The 5th Harmonic blocking feature is available for possible use to prevent unwanted operation of the low set differential element under transient overfluxing conditions.

When overfluxing occurs, the transformer core becomes partially saturated and the resultant magnetizing current waveforms increase in magnitude and become harmonically distorted. Such waveforms have a significant 5th harmonic content, which can be extracted and used as a means of identifying the abnormal operating condition.

The 5th harmonic blocking threshold, Xform Ih(5)%> in the DIFFERENTIAL menu, is adjustable between 0 - 100% differential current. The threshold should be adjusted so that blocking will be effective when the magnetizing current rises above the chosen threshold setting of the low-set differential protection.

For example, when a load is suddenly disconnected from a power transformer the voltage at the input terminals of the transformer may rise by 10-20% of the rated value. Since the voltage increases, the flux, which is the integral of the excitation voltage, also increases. As a result, the transformer steady state excitation current becomes higher. The resulting excitation current flows in one winding only and therefore appears as differential current which may rise to a value high enough to operate the differential protection. A typical differential current waveform during such a condition is shown in Figure 45. A typical setting for Xform Ih(5)%> is 35%

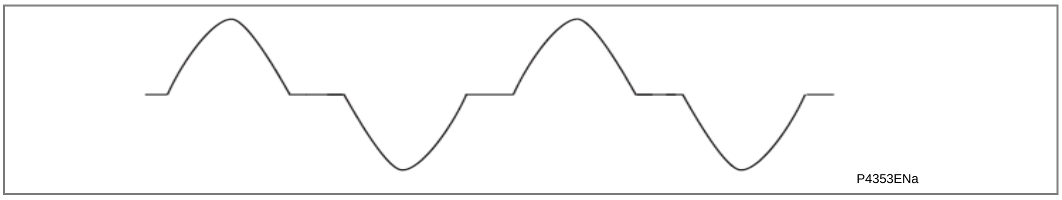


Figure 45 - Typical overflux current waveform

To offer some protection against damage due to persistent overfluxing that might be caused by a geomagnetic disturbance, the 5th harmonic blocking element (DDB 1275/1276/1277, 5th Harm Blk A/B/C) can be routed to an output contact using an associated PSL timer. Operation of this element could be used to give an alarm to the network control centre. If such alarms are received from a number of transformers, they could serve as a warning of geomagnetic disturbance so that operators could take some action to safeguard the power system. Alternatively this element can be used to initiate tripping in the event of prolonged pick up of a 5th harmonic measuring element. It is not expected that this type of overfluxing condition would be detected by the AC overfluxing protection. This form of time delayed tripping should only be applied in regions where geomagnetic disturbances are a known problem and only after proper evaluation through simulation testing.

2.23.2 Setting Guidelines for Overfluxing Protection

The V/Hz>1 overfluxing protection element trip stage can be selected by setting the V/Hz Trip Func cell to the required time delay characteristic; DT for definite time operation, IDMT, for inverse time operation. The four overfluxing protection trip stages can be Enabled/Disabled in the V/Hz>x Status cells.

The overfluxing protection alarm stage may be Enabled/Disabled in the V/Hz Alarm Status cell.

In general, a generator or generator transformer overflux condition will occur if the V/Hz ratio exceeds 1.05 p.u. i.e. a 5% overvoltage condition at rated frequency.

The element is set in terms of the actual ratio of voltage to frequency; the overfluxing threshold setting, V/Hz>x Trip Setting, can therefore be calculated as shown below:

A 1.05 p.u. setting = 110/50 x 1.05 = 2.31

Where:

- The VT secondary voltage at rated primary volts is 110 V
- The rated frequency is 50 Hz

The overfluxing alarm stage threshold setting, V/Hz Alarm Set, can be set lower than the trip stage setting to provide an indication that abnormal conditions are present and alert an operator to adjust system parameters accordingly.

The time delay settings should be chosen to match the withstand characteristics of the protected generator or generator/transformer. If an inverse time characteristic is selected, the time multiplier setting, V/Hz>1 Trip TMS, should be chosen so the operating characteristic closely matches the withstand characteristic of the generator or generator/transformer. If a definite time setting is chosen for the trip stages the time delay is set in the V/Hz>x Trip Delay cells. The alarm stage time delay is set in the V/Hz Alarm Delay cell.

The 3 definite time stages and 1 DT/IDMT stage can be combined to create a combined multi-stage V/Hz trip operating characteristic using PSL, see examples above.

Reference should be made to manufacturers withstand characteristics before formulating these settings.

2.24 Rate of Change of Frequency Protection (81R)

The two main applications for df/dt protection are network decoupling (loss of mains/loss of grid) and load shedding.

2.24.1 Load Shedding

Generated and required active power 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 into a healthy condition, a 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 frequency decay needs to be monitored over a longer period of time and time delayed df/dt can be used to make the correct decision for load shedding or 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.

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 on a measurement of rate of change of frequency and bypassing the time delay.

A time delayed rate of change of frequency monitoring element that operates independently from the under and over frequency protection functions could be used to provide extra flexibility to a load shedding scheme in dealing with such a severe load to generation imbalance. A more secure load shedding scheme could be implemented using f + df/ft by supervising the df/dt element with under frequency elements.

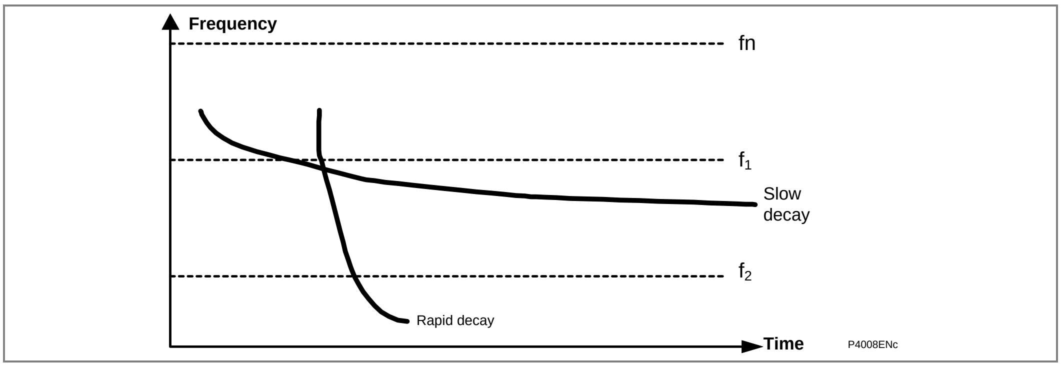


Figure 46 - Rate of change of frequency protection

2.24.2 Loss of Mains Protection

If the capacity of an embedded generator exceeds the locally connected load it is conceivable that it could supply the local load in island mode. Fault clearance may disconnect part of the public supply system from the main source of supply resulting in the embedded generation feeding the local loads, i.e. a 'Loss of Mains' or 'Loss of Grid' condition. This is shown in Figure 47. A fault at F will result in the tripping of CB1 disconnecting substations S1, S2 and S3 from the main source of supply. Also note that transformer T1 was supplying the earth connection for S1, S2 and S3, this earth connection is lost when CB1 opens. Should the load at substations S1 and S2 greatly exceed the rating of EG1, the generator will slow down quickly and underfrequency and/or undervoltage relays could operate to disconnect EG1 from the system. The worst scenario is when the external load is smaller than the generator rating; in this case the generator can continue to operate normally supplying the external loads. The local system will now be operating unearthed and overcurrent protection may be inoperative at S1 and S2 due to the low fault supplying capacity of generator EG1. The embedded generator may also lose synchronism with the main system supply leading to serious problems if CB1 has auto-reclosing equipment.

An even more serious problem presents itself if manual operation of distribution switchgear is considered. System Operation staff may operate circuit breakers by hand. In these circumstances it is essential that unsynchronized reclosure is prevented as this could have very serious consequences for the operator, particularly if the switchgear is not designed, or rated, to be operated when switching onto a fault. To protect personnel, the embedded machine must be disconnected from the system as soon as the system connection is broken, this will ensure that manual unsynchronized closure is prevented.

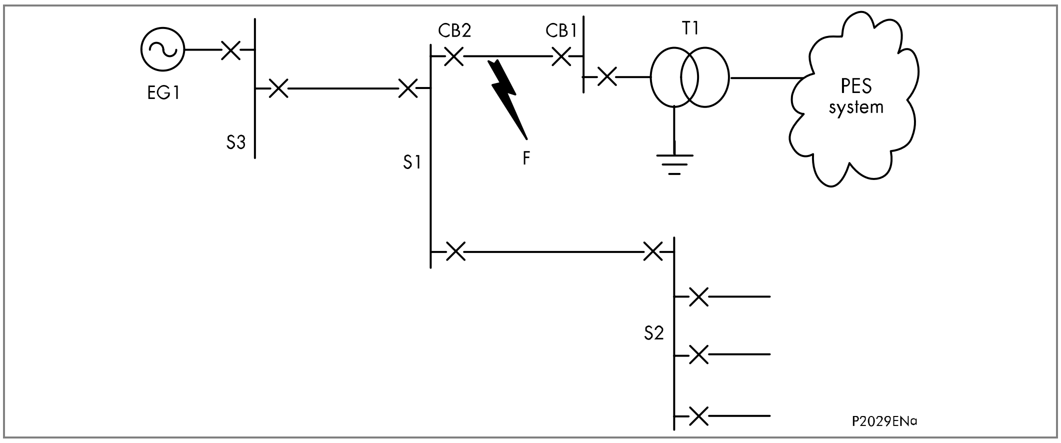


Figure 47 - Typical system with embedded generation

Where the embedded generator does not export power under normal conditions it may be possible to use directional power or directional overcurrent protection relays to detect the export of power under loss of mains conditions. If export of power into the system is allowed it may not be possible to set directional relays using settings sensitive enough to detect the loss of the mains connection. In such circumstances a rate of change of frequency protection can be applied. This detects the slight variation in generator speed that occurs when the main supply connection is disconnected and the generator experiences a step change in load.

The type of protection required to detect Loss of Mains conditions will depend on a number of factors, e.g. the generator rating, size of local load, ability to export power, and configuration of supply network etc. Protection requirements should be discussed and agreed with the local Public Electricity Supplier before permission to connect the embedded generator in parallel with the system is granted.

A number of protection elements that may be sensitive to the Loss of Mains conditions are offered in the P34x & P391 relay; rate of change of frequency, overpower protection, directional overcurrent protection, frequency protection, voltage protection. Application of each of these elements is discussed in more detail in the P341 manual.

When a machine is running in parallel with the main power supply the frequency and hence speed of the machine will be governed by the grid supply. When the connection with the grid is lost, the islanded machine is free to slow down or speed up as determined by the new load conditions, machine rating and governor response. Where there is a significant change in load conditions between the synchronized and islanded condition the machine will speed up or slow down before the governor can respond.

The rate of change of speed, or frequency, following a power disturbance can be approximated by:

$$^{df}/_{dt} = \frac{\Delta P.f}{2GH}$$

Where

P	=	Change in power output between synchronized and islanded operation
f	=	Rated frequency
G	=	Machine rating in MVA
H	=	Inertia constant

This simple expression assumes that the machine is running at rated frequency and that the time intervals are short enough that AVR and governor dynamics can be ignored. From this equation it is clear that the rate of change of frequency is directly proportional to the change in power output between two conditions. Provided there is a small change in load between the synchronized and islanded (loss of mains) condition the rate of change of frequency as the machine adjusts to the new load conditions can be detectable. The change in speed of the machine is also proportional to the inertia constant and rating of the machine and so will be application dependent.

Care must be taken in applying this type of protection as the prime consideration is detecting the loss of grid connection. Failure to detect this condition may result in unsynchronized re-connection via remote re-closing equipment. However, if too sensitive a setting is chosen there is a risk of nuisance tripping due to frequency fluctuations caused by normal heavy load switching or fault clearance. Guidance can be given for setting a rate of change of frequency element but these settings must be thoroughly tested on site to prove their accuracy for a given machine and load.

The element also allows the user to set a frequency band within which the element is blocked. This provides additional stability for non loss of grid disturbances which do not affect the machine frequency significantly.

2.24.3 Setting Guidelines for df/dt Protection

There are some global df/dt settings that affect all protection stages that can be used to smooth out the frequency measurements and provide stable operation of the protection, df/dt avg cycles and df/dt iterations. These settings enable the user to select the number of cycles the frequency is averaged over and the number of iterations of the averaged cycles before a start is given. Two Operating Mode settings are provided: Fixed Window and Rolling Window. The Fixed Window setting is mainly provided for compatibility with the previous P341 df/dt function which used two consecutive calculations of a 3 cycle fixed window to initiate a start.

The previous software version P341 df/dt element calculated the rate of change of frequency every 3 cycles by calculating the frequency difference over the 3-cycle period as shown below.

$$^{df}/_{dt} = \frac{f_n - f_{n\text{-}3cycle}}{3cycle}$$

Two consecutive calculations must give a result above the setting threshold before a trip decision can be initiated.

For loss of grid applications it is recommended that df/dt avg cycles = 3 and df/dt iterations = 2 and the Operating Mode = Fixed Window as per the original P341 algorithm.

For load shedding applications the df/dt avg cycles and df/dt iterations and the Operating Mode, Fixed Window/Rolling Window will depend on the operating time and stability requirements. The df/dt measurement will provide more stability to power system oscillations when the number of iterations and averaging cycles is high but this will make the function slower. Typical settings for load shedding applications are df/dt avg cycles = 5, df/dt iterations = 1 and the Operating Mode = Rolling Window. For load shedding applications with low df/dt settings < 0.5 Hz/s higher settings for the averaging cycles and iterations should be considered to provide better stability.

The df/dt feature is available only when the df/dt option is enabled in the CONFIGURATION menu. All four stages may be enabled/disabled by the df/dt>n Status cell depending on which element is selected.

Each stage has a direction setting df/dt>n Dir'n – Negative, Positive, Both. This setting determines whether the element will react to rising or falling frequency conditions respectively, with an incorrect setting being indicated if the threshold is set to zero. For loss of mains applications the df/dt>1 Dir'n should be set to Both to match the previous P341 algorithm.

A sudden disconnection of loads leads to a surplus of active power. The frequency rises and causes a positive frequency change. A failure of generators, on the other hand, leads to a deficit of active power. The frequency drops and leads to a negative frequency change. For load shedding applications the df/dt>1 Dir'n is typically set to Negative for falling frequencies.

For loss of mains applications the df/dt>1 setting threshold should be set such that the loss of mains condition can be detected; this can be determined by system switching during initial commissioning. A typical setting for df/dt>1 Setting is 0.2 to 0.6 Hz/s. For df/dt>1 only, the user can select a deadband around the nominal frequency, within which this element is blocked. The dead band is defined with high and low frequency settings df/dt>1 f Low and df/dt> f High. The deadband is eliminated if the high and low frequencies are set the same or the df/dt> f L/H setting is set to Disabled. The deadband provides additional stability for non loss of grid disturbances which do not affect the machine frequency significantly.

System simulation testing has shown that the following settings can provide stable operation for external faults, and load switching events, whilst operating for a loss of mains event which causes a 10% change in the machine output, for a typical 4 MW machine. These can be used as a guide but will by no means be acceptable in all applications. Machine rating, governor response, local load and system load, will all affect the dynamic response of a machine to a loss of mains event.

df/dt>1 Setting	–	0.2 Hz/s
df/dt Time Delay	–	0.5 s
df/dt>1 f High	–	50.5 Hz
df/dt>1 f Low	–	49.5 Hz
df/dt>1 Dir'n	–	Both

Once installed, the settings should be periodically reviewed to ensure that they are adequate to detect a loss of grid connection event, but not too sensitive such that unwanted tripping occurs during normal fault clearance, or load switching, that does not lead to the loss of mains condition. Safety of personnel is paramount and this should be kept in mind when optimizing settings; non-synchronized manual operation of circuit breakers must be prevented by disconnection of the embedded machine when the system becomes separated.

For load shedding the df/dt>n setting value depends on the application and is determined by power system conditions. In most cases, a network analysis will be necessary. The under/overfrequency start DDBs can be used to supervise the df/dt elements using the df/dt>1/2/3/4 Tmr Blk DDBs, if required to provide a more secure load shedding scheme.

The following can be used as an example for estimation of the df/dt settings. This applies for the change rate at the beginning of a frequency change (approx. 1 second).

$$\frac{df}{dt} = \frac{\Delta P.f}{2GH}$$

For hydro-electric generators (salient-pole machines) H = 1.5 s to 6 s

For turbine-driven generators (cylindrical-rotor machines) H = 2 s to 10 s

For industrial turbine-generators H = 3 s to 4 s

f = nominal frequency

H = 3 s

Case 1: ΔP/G = 0.12

Case 1: ΔP/G = 0.48

Case 1: df/dt = -1 Hz/s

Case 2: df/dt = -4 Hz/s

The time delay setting, df/dt>n Time Delay, can be used to provide a degree of stability against normal load switching events which will cause a change in the frequency before governor correction.

2.25 Dead Machine/Unintentional Energization at Standstill Protection (50/27)

Accidental energization of a generator when the machine is not running can cause severe damage to the machine. If the breaker is closed, when the machine is at standstill, the generator will begin to act as an induction motor with the surface of the rotor core and the rotor winding slot wedges acting as the rotor current conductors. This abnormal current in the rotor can cause arcing between components, e.g. slot wedge to core, and results in rapid overheating and damage.

To provide fast protection for this condition, the P343/P344/P345 relay provides an instantaneous overcurrent element that is gated with a three-phase undervoltage detector.

The element is enabled when the machine is not running, i.e. not generating any voltage, or when the breaker is open. Therefore the element can have a low current setting, resulting in high speed operation when required. For the element to operate correctly the relay voltage input must be from a machine side VT; busbar VTs cannot be used.

In the P343/P344/P345 the 3 phase current source for the low impedance dead machine protection can be selected using the DM CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting. In the standard connection diagrams in the installation chapter, *P34x & P391/EN IN*, IA-1/IB-1/IC-1 is connected to the neutral side CTs and IA-2/IB-2/IC-2 is connected to the terminal side CTs.

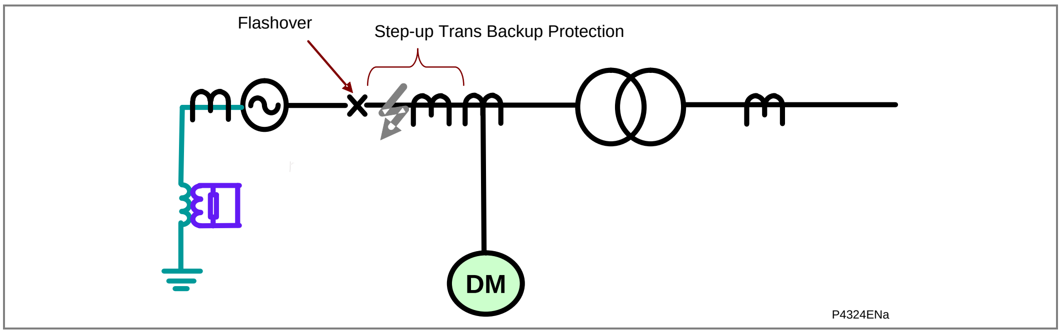


Figure 48 - GCB flashover and transformer back-up protection

If the CT inputs of the dead machine protection are selected to use the generator terminal side CTs as shown above, after the generator CB is open, the protection can also act as the generator CB flashover and back-up protection for the step-up transformer. Otherwise the fault as shown in the figure above has to be cleared by the overcurrent protection located on the main transformer HV side. The HV overcurrrent protection is not as sensitive or as fast as the dead machine protection which can be set instantaneous and with a sensitive current setting for this application. The dead machine voltage threshold should be set with a low setting to indicate the generator CB is open, e.g. 10 V secondary is equivalent to the pole dead voltage threshold used in the P34x & P391.

2.25.1 Setting Guidelines for Dead Machine Protection

The dead machine protection element can be selected by setting the Dead Mach Status cell to Enabled.

In the P343/P344/P345 select the 3 phase current source for the low impedance dead machine protection using the DM CT Source – IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 setting. In the standard connection diagrams in the installation chapter, *P34x & P391/EN IN*, IA-1/IB-1/IC-1 is connected to the neutral side CTs and IA-2/IB-2/IC-2 is connected to the terminal side CTs. For most applications either the neutral or terminal side CTs can be used.

The overcurrent threshold, Dead Mach I>, can be set to less than full load current as the element will not be enabled during normal machine operation. A setting of 10% of full load current can typically be used.

The undervoltage threshold, Dead Mach V<, should typically be set at 85% of the nominal voltage to ensure that the element is enabled when the machine is not running.

The pick-up time delay, Dead Mach tPU, which provides a small time delay to prevent initialization of the element during system faults, should typically be set to 5 s, or at least in excess of the protection clearance time for a close up phase to phase fault.

The drop off time delay, Dead Mach tDO, ensures that the element remains initialized following accidental closure of the circuit breaker, when the undervoltage detector could reset. A delay of 500 ms will ensure that the element can operate when required.

2.26 Resistive Temperature Device (RTD) Thermal Protection

Prolonged overloading of generators may cause their windings to overheat, resulting in premature ageing of the insulation, or in extreme cases, insulation failure. Worn or unlubricated bearings can also generate localized heating within the bearing housing. To protect against any general or localized overheating, the P342/P343/P344/P345 relay has the ability to accept inputs from up to 10 - 3 wire Type A PT100 Resistive Temperature Sensing Devices (RTDs).

Such probes can be strategically placed in areas of the machine that are susceptible to overheating or heat damage. Where power transformers are located close to the protected machine, certain RTD probes could be assigned to provide overtemperature protection for the transformer(s). This could protect against winding hot spot overheating or overtemperature in the bulk of the insulating oil.

Typically a PT100 RTD probe can measure temperature within the range –40° to +300°C. The resistance of these devices changes with temperature, at 0°C they have a resistance of 100 Ω. The temperature at each probe location can be determined by the relay, and is available for:

- Temperature monitoring, displayed locally, or remotely via the relay communications
- Alarming, should a temperature threshold be exceeded for longer than a set time delay
- Tripping, should a temperature threshold be exceeded for longer than a set time delay

Should the measured resistance be outside of the permitted range, an RTD failure alarm will be raised, indicating an open or short circuit RTD input.

Note	*Direct temperature measurement can provide more reliable thermal protection than devices that use a thermal replica energized from phase current. The latter is susceptible to inaccuracies in time constants used by the replica model, and also inaccuracies due to the variation in ambient temperature.*

See the Installation chapter (*P34x & P391/EN IN*), for recommendations on RTD connections and cables.

2.26.1 Setting Guidelines for RTD Thermal Protection

Each RTD can be enabled by setting the relevant bit in Select RTD. For example if Select RTD is set to 0000000111, then RTD1, RTD2 and RTD3 would be enabled and the associated settings would be visible in the menu.

The temperature setting for the alarm stage for each RTD can be set in the RTD x Alarm Set cells and the alarm time delay in the RTD x Alarm Dly cell.

The temperature setting for the trip stage for each RTD can be set in the RTD x Trip Set cells and the trip stage time delay in the RTD x Trip Dly cell.

Typical operating temperatures for protected plant are given in the table below. These are provided as a guide, actual figures must be obtained from the equipment manufacturers:

Parameter	Typical service temperature	Short term overloading at full load
Bearing temperature generators	60 - 80°C, depending on the type of bearing.	60 - 80°C+
Top oil temperature of transformers	80°C (50 - 60°C above ambient).	A temperature gradient from winding temperature is usually assumed, such that top oil RTDs can provide winding protection

Parameter	Typical service temperature	Short term overloading at full load
Winding hot spot temperature	98°C for normal ageing of insulation. Cyclic overloading might give	140°C+ during emergencies

Table 9 - Typical operating temperatures of plant.

2.27 P342 Pole Slipping Protection (78)

A generator might pole slip, or fall out-of-step with other power system sources, in the event of failed or abnormally weak excitation or as a result of delayed system fault clearance. This can be further aggravated when there is a weak (high reactance) transmission link between the generator and the rest of the power system.

The process of pole slipping following excitation failure is discussed in section 2.14. The P342 field failure protection function should respond to such situations to give a time delayed trip. The electrical/mechanical power/torque oscillations following excitation failure may be relatively gentle. If pole slipping occurs with maximum excitation (generator e.m.f. >2.0 p.u.), the power/torque oscillations and power system voltage fluctuations following loss of stability can be much more severe. For large machines there may be a requirement to provide protection to trip the generator under such circumstances, to prevent plant damage or remove the disturbance to the power system.

Pole slipping protection is frequently requested for relatively small generators running in parallel with strong public supplies. This might be where a co-generator runs in parallel with the distribution system of a public utility, which may be a relatively strong source, but where high-speed protection for distribution system faults is not provided. The delayed clearance of system faults may pose a stability threat for the co-generation plant.

With the P342 relay there is no specific pole slipping protection function, but a number of the protection functions provided can offer a method of ensuring delayed tripping, if appropriately applied.

2.27.1 Reverse Power Protection

During a pole slipping event the machine will cyclically absorb and export power as the machine rotor slips with respect to the power system. Therefore, any power element selected to operate from reverse power can pick-up during the pole slip. Reverse power protection tripping is usually time delayed and this time delay will prevent the element from tripping during a pole slip. However, each power protection stage in the P342 relay has an associated delay on drop off, or reset, timer (Power1 DO Timer, Power2 DO Timer). This can be used to prevent resetting of the reverse power stage during a pole slipping event, leading to eventual tripping if the event continues.

2.27.2 System Back-up Protection Function

In a similar manner to the power protection function, the system back-up protection function would operate cyclically with the periodic high levels of stator current that would arise during pole slipping. These peaks of current may also be accompanied by coincident drops in generator terminal voltage, if the generator is near the electrical center of swinging.

As discussed in section 2.7, the system back-up protection function is provided with a timer characteristic timer-hold setting, V Dep OC tRESET, Z< tRESET, which can be used to ensure that the protection function will respond to cyclic operation during pole slipping. In a similar manner, some operators of small, unmanned hydro-generators have relied on the integrating action of induction disc overcurrent protection to ensure disconnection of a persistently slipping machine.

2.27.3 Field Failure Protection Function

Slightly faster pole slipping protection might be assured in many applications by appropriately applying the field failure protection function and associated scheme logic timers.

Where the power system source impedance is relatively small in relation to the impedance of a generator during pole slipping, the electrical center of slipping is likely to lie within the generator. This would be ‘behind’ the relaying point, as defined by the location of the voltage transformer. Such a situation is likely to exist for co-generation schemes and might also be the case for some fairly large utility generation schemes connected to a densely interconnected transmission system. The dynamic impedance of the generator during pole slipping (Xg) should lie between the average value of the direct and quadrature axis transient reactance's (Xd' and Xq') and the average value of the direct/quadrature axis synchronous reactance's (Xd and Xq). However neither extreme would actually be reached. During low-slip periods of a pole slip cycle, the synchronous reactance's would apply, whereas the transient impedance's would apply during periods of relatively high slip.

Figure 49 shows how the impedance seen at the generator protection relaying point may vary during pole slipping for a relatively small co-generator directly connected to a relatively strong distribution power system. The behavior of a generator during pole slipping may be further complicated by intervention of an automatic voltage regulator and by the response of any speed-dependent excitation source (e.g. shaft-driven exciter).

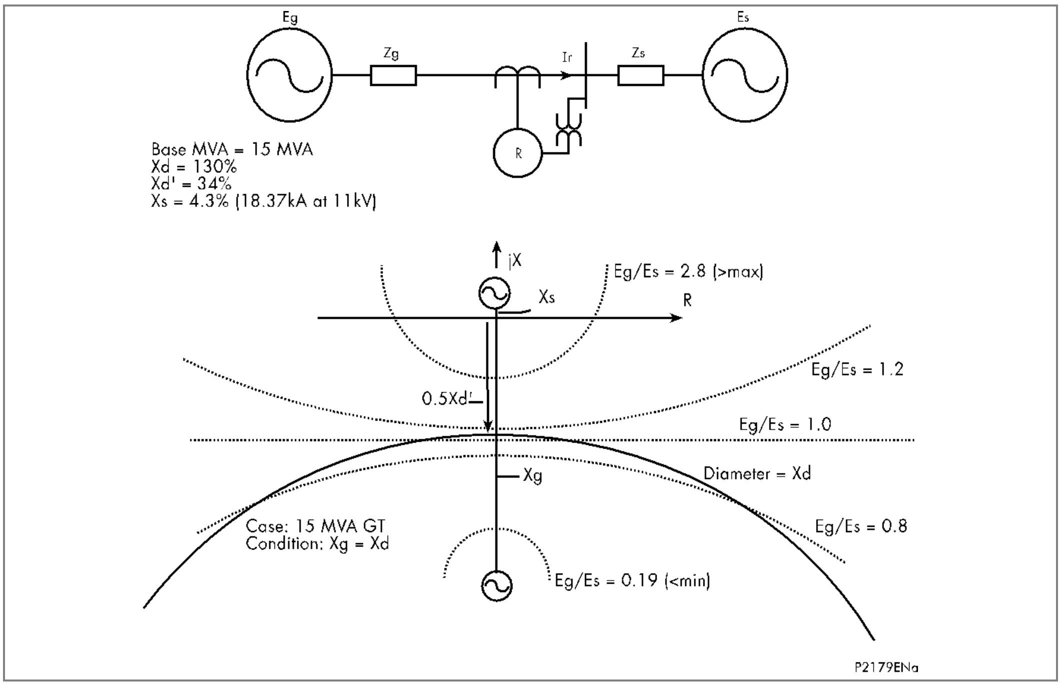


Figure 49 - Field failure protection function characteristics (small co-generator)

It can be seen from the simple analysis of Figure 49 that the field failure protection function may respond to the variation in impedance seen during pole slipping for some applications. However the impedance characteristic offset might have to be reduced to guarantee response for the theoretical lower range of dynamic generator impedance (Xg). The lack of the normally recommended characteristic offset should not pose any problem of unwanted protection function response during the normal range of operation of a machine (with rotor angles kept below 90°), but a longer trip time delay might be required to prevent unwanted protection response during stable power swings caused by system disturbances.

The most marginal condition to detect is where the generator is fully loaded, with maximum excitation applied. Even if the impedance characteristic offset is not reduced, impedance element pick up should still occur during part of a slip cycle, when the machine impedance is high and where the rotor angle is high. More careful consideration might have to be given to the reset time delay setting (FFail1 DO Timer) required in such circumstances.

During pole slipping, any operation of the field failure protection function will be cyclic and so it would be necessary to set the reset time delay (FFail1 DO Timer) to be longer than the time for which the impedance seen will cyclically lie outside the field failure characteristic. A typical delay setting might be 0.6 s, to cover slip frequencies in excess of 2 Hz. When the timer FFail1 DO Timer is set, the field failure trip time delay (FFail1 Time Delay) must be increased to be greater than the setting of FFail1 DO Timer.

Sometimes pole slipping protection must be guaranteed, especially in the case of a larger utility generator connected to a relatively weak transmission system. In such applications, and where fast tripping is required, or where the pole slipping response of field failure protection function is otherwise uncertain, a stand-alone protection scheme, such as used in the P343/P344/P345 should be used. The delayed detection and tripping offered by the P34x & P391 Field Failure protection function should, however, be adequate for many applications.

For further details regarding setting of field failure protection for time delayed pole slipping detection, contact Schneider Electric.

2.28 P343/P344/P345 Pole Slipping Protection (78)

2.28.1 Introduction

Sudden changes or shocks in an electrical power system such as line switching operations, large jumps in load or faults may lead to power system oscillations which appear as regular variations of the currents, voltages and angular separation between systems. This phenomenon is referred to as a power swing.

In a recoverable situation, the power swing will decay and finally disappear in a few seconds. Synchronism will be regained and the power system will recover to stable operation. In a non-recoverable situation, the power swing becomes so severe that synchronism is lost between the generator and system, a condition recognized as out-of-step or pole slipping from the view of a generator. If such a loss of synchronism does occur, it is imperative to separate the asynchronous areas from the rest of the system before generators are damaged or before a widespread outage can occur.

Pole slipping occurs when the prime mover input power of a generator exceeds the electrical power absorbed by the system. The condition results from the mismatch in the operating frequencies of two or more machines. During pole slipping the machine produces alternatively generating and motoring torque of high magnitudes with corresponding current peaks and voltage dips.

During normal system operation the following events can lead to the generator pole slipping condition.

- The occurrence of an abnormality such as:
  - A transient system fault.
  - The failure of the generator governor.
  - The failure of the generator excitation control (asynchronous running).
- Reconnection of an 'islanded' system without synchronization.
  - The transient change in the system requirements of real and reactive power components sets the generator rotor to oscillate around the new equilibrium point.
  - If the initial transient disturbance is severe enough and for a sufficiently long duration the rotor swing may exceed the maximum stability limit causing the generator to slip poles.
  - For a weak system switching transients may also result in pole slipping.

Nowadays, with the advent of EHV systems, large conductor-cooled generators and with the expansion of the transmission system, system and generator impedances have changed considerably. System impedances have decreased while generator and step-up transformer impedances have increased. This trend has resulted in the impedance center during a power swing appearing inside the step-up transformer or inside the generator that is generally out of the protection zone of conventional out-of-step relays installed in the system. Therefore separate relaying should be applied to protect the machine against pole slipping.

Relays employing impedance-measuring elements for the detection of the pole slipping condition utilize the generator terminal voltage and current signals as inputs. During a generator pole slip the system voltage and current go through slip frequency variations of extremely high amplitude. These variations are reflective of the corresponding apparent changes in the generator terminal impedance. The relay will be able to detect the condition only after the generator has actually slipped poles. The conventional technique employs measurement of generator terminal impedance to determine pole slipping conditions. Directional and blinder elements are used together with a mho element to obtain the desired relay characteristics.

2.28.2 Loss of Synchronism Characteristics

Before any further discussion, it is necessary to have a brief review of the loss of synchronism characteristic that is used in the analysis of generator pole slipping.

A common method used to detect a loss of synchronism is to analyze the apparent impedance as measured at the generator terminals. According to the simplified representation of a machine and system shown in Figure 50, the impedance presented to the relay ZR (installed at point A) under a loss of synchronism (recoverable power swing or pole slipping) condition can be described by equation1:

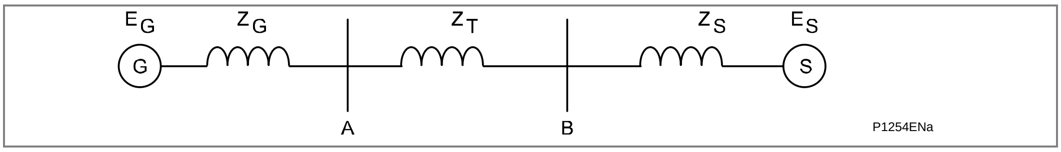


Figure 50 - Simplified two machine system

Where:

EG = The generator terminal voltage

ZG = The generator impedance

ZT = The impedance of step-up transform

ZS = The impedance of the power system connected to the generation unit

ES = The system voltage

$$Z_R = \frac{(Z_G + Z_T + Z_S)\, n\, (n - \cos\delta - j \sin\delta)}{(n - \cos\delta)^2 + \sin^2 \delta} - Z_G \text{ ---------------------} \quad \text{Equation 1}$$

Where:

$n = \dfrac{E_G}{E_S}$ = magnitude ratio of generator terminal voltage to the system voltage

$\delta = \arg \dfrac{\dot{E}_G}{\dot{E}_S}$ = rotor angle by which generator terminal voltage leads system voltage

The apparent impedance as viewed at the generator terminals (Point A) will vary as a function of the ratio n and the angular separation δ between the machine and the system. With the aid of the R/X impedance diagram, a set of impedance loci representing a loss of synchronism along with the system impedances are plotted as shown in Figure 51.

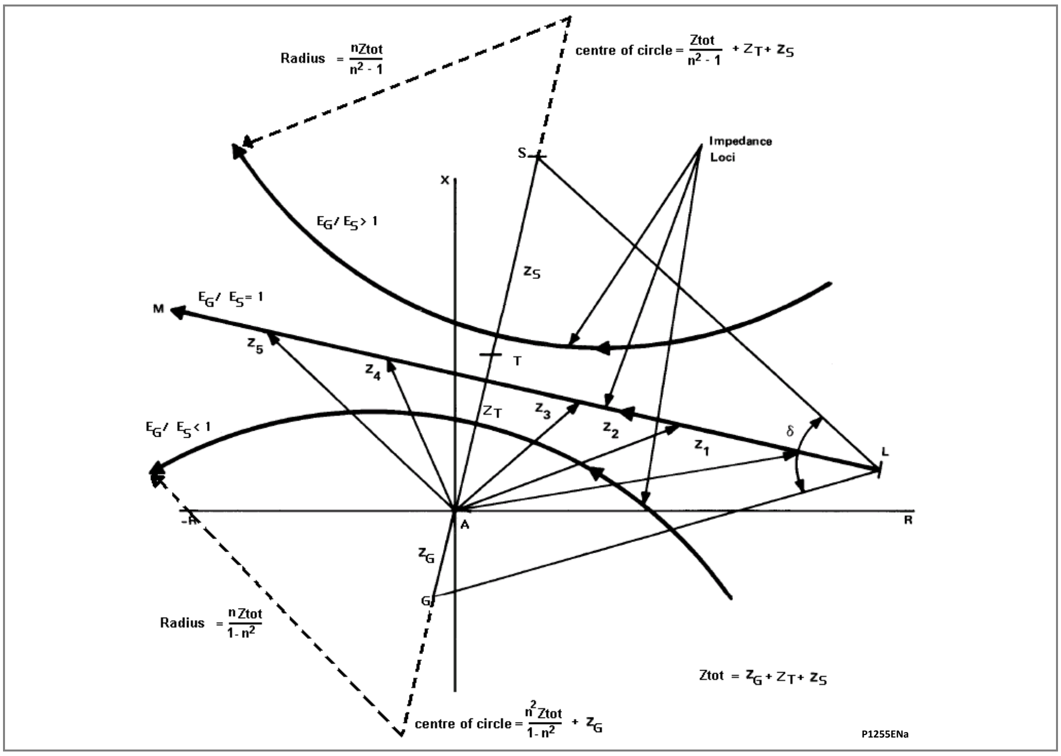


Figure 51 - Apparent impedance loci viewed at the generator terminal (point A)

It has been well proven that the locus of the impedance as measured at the generator terminals (point A) is either a straight line or circular depending on whether E_G and E_S are of equal or different magnitudes. The impedance locus is a straight line which is a perpendicular bisector of the total system impedance between G and S when EG / ES = 1. When E_G / E_S > 1, the circular locus is located above the bisector with its center on the extension of the total impedance line GS. When E_G / E_S < 1, the impedance locus is situated below the bisector with its center on the extension of the total impedance line SG.

The diameters and centers of these circles are a function of the voltage ratio E_G / E_S and the total impedance, as shown in Figure 51. It is not always necessary to go into the detail of plotting the circular characteristic to identify the loss of synchronism. In most cases, it is only necessary to simply draw the perpendicular bisector to the total impedance line to locate the point on the system where the swing will traverse which is sufficiently accurate for relaying purposes.

The angle formed by the intersection of lines SL and GL on line ML is the angle of separation δ between the generator and system. During an unrecoverable power swing, δ oscillates between 0 and 360 degrees according to the points L and M on the bisector. There are several points of interest along line LM. The first is the point where the separation reaches 90 degrees. If we draw a circle whose diameter is the total impedance, line GS, the intersection of the circle and line LM will be the point where δ=90 degrees. If the swing locus does not go beyond this point the system will be able to regain synchronism. However, if the locus reaches 120 degrees or more, the system is not likely to recover. When the impedance locus intersects the total impedance, line GS, the generator and system are 180 degree out of phase, which is known as the electrical center or impedance center of the system. As the locus crosses this point and enters the left hand side of the line GS, the generator and system will become more in phase. A slip cycle has been completed when the locus reaches the point where the swing started.

Note	*The following assumptions have been made in this simplified approach:* *E_G/E_S is assumed to remain constant during the swing* *Initial transients and effects of generator saliency are neglected* *Transient changes in impedance due to a fault or clearance of fault have subsided* *Effect of regulator and governor are neglected*

2.28.3 Generator Pole Slipping Characteristics

As noted previously, generator and system impedances have changed in the past few decades. In many instances, the electrical center or impedance center lies within the generator or step-up transformer. Also, for most machine loadings, the equivalent internal machine voltage will be less than 1.0 per unit and so less than the equivalent system voltage. Therefore the pole slipping characteristics viewed at the generator terminals will generally follow the loss of synchronism characteristic where the voltage ratio $E_G/E_S < 1$ which is below the impedance center. See the locus $E_G/E_S < 1$ in Figure 51 for example.

In reality the impedance loci as viewed at the generator terminals may be distorted compared with the ideal loci. The following discussion illustrates the impact on the pole slipping characteristic when other factors are taken into account.

2.28.3.1 What happens if EG/ES has Different Values less than one (1)?

For a given total impedance, as the voltage ratio decreases below one (1), the circle also decreases in diameter and the center moves closer to the origin. Therefore, a decreased internal voltage results in the impedance loci having a smaller diameter. The radius and circular center calculations using the equation shown in Figure 51 shows these trends.

During a fault, if the voltage regulator is out of service the internal machine voltage will decay and will remain at the resulting lower level after the fault is cleared. If the effects of the voltage regulator during a fault is included, the impedance locus circles are larger in diameter but will still be in the generator zone.

2.28.3.2 What happens if different System Impedances are applied?

System impedance also plays a part in the determination of the circle diameter and location. If the system impedance decreases, the locus decreases in diameter and moves closer to the origin.

The impedance center of the system is not a fixed point due to the variation of system impedance under different operating conditions. Therefore the impedance loci should be determined at the maximum and minimum systems impedances.

2.28.3.3 How to Determine the Generator Reactance during a Pole Slipping Condition?

Since the generator reactance plays a role in the determination of the pole slipping impedance locus, it is crucial to use proper reactance values when we plot these loci. At zero slip X_G is equal to the synchronous reactance (Xd), and at 100% slip X_G is equal to sub-transient reactance (X''_d). The impedance in a typical case has been shown to be equal to the transient reactance X'_d at 50% slip, and to $2X'_d$ with a slip of 0.33%. As most slips are likely to be experienced at low asynchronous speed running, perhaps 1%, it is sufficient to take the value $X_G=2X'_d$ when assessing pole slipping.

2.28.3.4 How to Determine the Slip Rate of Pole Slipping

The rate of slip between the generator and power system is a function of the accelerating torque and inertia of the systems. In general, the slip rate can not be obtained analytically. It is recommended to determine the slip rate by transient stability studies where the angular excursion of the system is plotted versus time. Although the slip rate will not be constant during a pole slipping condition, it is reasonable to assume a constant for the first half slip cycle which is of interest to the relay. For the tandem generator, it is in the range of 250 to 400 degrees/sec. For the cross compound units, the average initial slip will be 400 to 800 degrees/sec.

2.28.4 General Requirements for Pole Slipping Protection

Having got some ideas about the characteristics of pole slipping, general rules for pole slipping protection could be obtained as listed below:

- On the whole, the pole slipping protection must remain stable under all fault conditions and recoverable power swings other than a genuine non-recoverable pole slipping condition.
- For a particular loss of synchronism condition, if the impedance center happens to lie in the generator/step-up transformer zone, it is recommended the generator be tripped without delay, preferably during the first half slip cycle of a loss of synchronism condition. If the center lies outside of the zone, then the pole slipping relay should not trip immediately, but should allow time for tripping to take place at some other location external to the power station. Only if this should fail must the pole slipping protection respond in stage II, i.e. after a pre-set number of slips, to isolate the generator.
- To reduce the damage to the generator during a pole slip, it must reliably detect the first and subsequent slips of a synchronous machine within a wide range (slipping frequency 0.1% to 10% of fn).
- The tripping should avoid the point where the generator and the system are 180 degrees out-of-phase, when the currents reach the maximum value and subject the circuit breaker to a maximum recovery voltage during interruption.
- Since pole slipping is essentially a balanced three-phase phenomenon, only a single-phase element need be implemented in the protection relay.

2.28.5 Lenticular Scheme

2.28.5.1 Characteristic

The P343/P344/P345 pole slipping characteristic consists of three parts as shown in the R/X diagram of Figure 52. The first part is the lenticular (lens) characteristic. The second is a straight line referred to as the blinder that bisects the lens and divides the impedance plane into the left and right halves. The third is a reactance line which is perpendicular to the blinder.

The inclination of the lens and the blinder, θ, is determined by the angle of the total system impedance. The equivalent impedance of the system and the step-up transformer determines the forward reach of the lens, Z_A, whereas the generator's transient reactance determines the reverse reach Z_B. The width of the lens is varied by the setting of the angle α. A reactance line, perpendicular to the axis of the lens, is used to distinguish whether the impedance center of the swing is located in the power system or in the generator. It is set by the value of Zc along the axis of the lens, as shown in Figure 52. The reactance line splits the lens into Zone 1 (lens below the line) and Zone 2 (all of the lens).

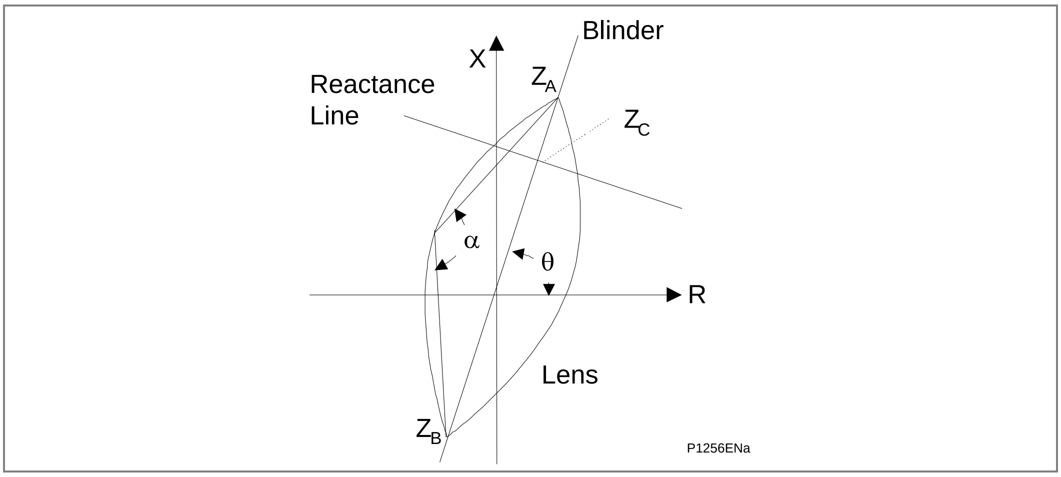


Figure 52 - Pole slipping protection using blinder and lenticular characteristic

2.28.5.2 Generating and Motoring Modes

When a generator is out of step with the system, the impedance locus is expected to traverse from right to left across the lens and the blinder. However, if the generator is running as a motor, as in the pumping mode of a pump storage generator, the impedance locus is expected to swing from the left to the right. A setting is provided to determine whether the protection operates in a generating mode or in a motoring mode or both. Also, when a generator is running at low load, <30% load, due to the presence of heavy system damping during a fault the generator can slow down and result in a motor like slip (negative slip). To detect pole slips for this condition then the Pole slip mode should be set to Both.

If the protection is running in the generating mode, the impedance is expected to be at the right hand side of the lens under normal load conditions. During a pole slip the impedance locus traverses across the right half and the left half of the lens. The minimum time spent in each half of the lens can be set with timers T1 for the right hand side and T2 for the left hand side. The relay registers a pole slipping cycle when the locus finally leaves the lens at the opposite end.

If the protection is running in the motoring mode, the impedance is expected to be at the left hand side of the lens under normal load conditions. During a pole slip the impedance locus traverses across the left half and the right half of the lens, again spending at least the time T1 and T2 respectively in each half and leaves the lens at the opposite end.

2.28.6 Setting Guidelines for Pole Slipping Protection

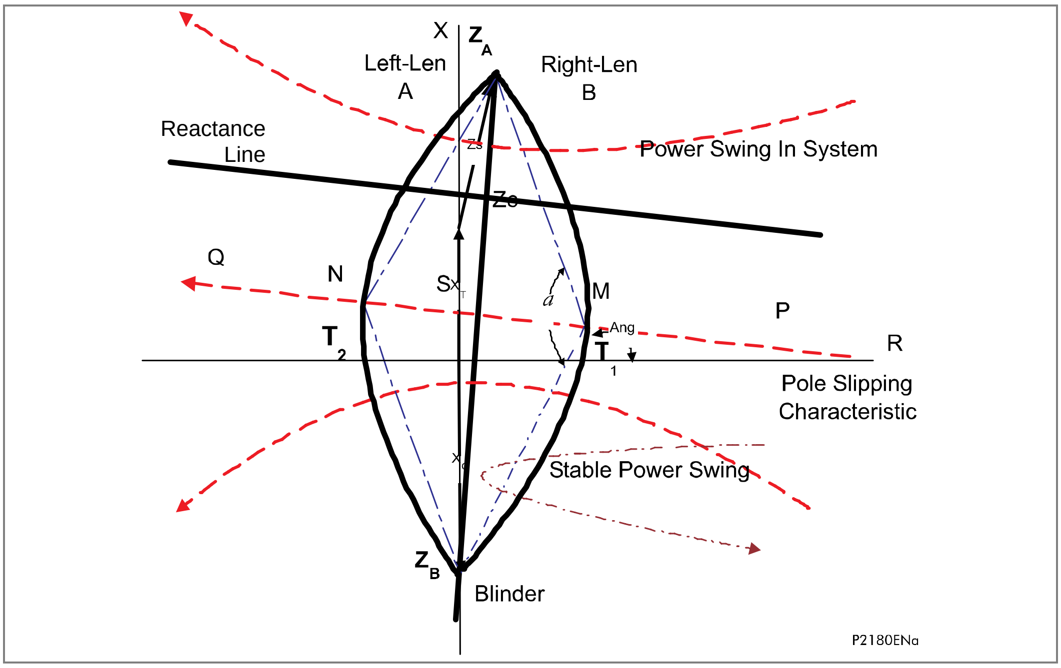


Figure 53 - Lenticular scheme characteristic

Forward reach and reverse reach Z_A, Z_B.

As noted previously, the best setting for the lens is when the point ZA and ZB coincide with the system impedance (ZT+ZS) and the generator reactance (XG), see Figure 53. The angle α of the lens corresponds in this case to the angle α between the emfs EG and ES at which the impedance enters the lens, see Figure 53.

As most slips are likely to be experienced at low asynchronous speed running, perhaps 1%, it is sufficient to take the value XG=2X'd when assessing pole slipping, see section 2.28.3.3.

Where the values of ZS and the generator reactance XG vary, ZA and ZB should be set according to the corresponding maximum values.

Large differences between EG and ES, see Figure 53 and sections 2.28.3.1, can cause the loci of impedance circle to becomes smaller and smaller. Therefore there is the possibility of the circular loci of the pole slip crossing the blinder and lens twice with large ZA and ZB settings producing a long lens. However, the state machine logic will prevent 2 pole slips from being counted for this condition and so there is no maximum limit to the ZA and ZB settings.

Lens inclination θ

The inclination of the lens should be kept consistent with the system impedance angle, vector GS in Figure 53.

Angle α.

The width of the lens is proportional to the angle α. Two factors should be considered to determine the proper angle α:

- Under all conditions, the load impedance remains safely outside the lens.
- The tripping point, limited by the left side of the lens for generating should be the point when the angular separation between the system and the generator is small. Although CBs are rated to break twice the system voltage i.e. when the machines are in anti-phase, it is recommended that the trip command is issued at the smallest phase shift possible. For this reason the angle α should be chosen as small as possible (setting range is 90° to 150°).

The construction of the lens can be seen in Figure 54, ZR is the maximum width of half the lens. The minimum resistive component of the load should be at least 130% of the reach of the lens, ZR, in the transverse direction. ZR can be determined by calculation as follows:

ZR = (ZA + ZB) /2 x tan (90° - α/2)

For a given minimal load resistance RLmin the minimum permissible setting of α is:

αmin = 180° – 2 x tan-1 (1.54 x RLmin / (ZA + ZB))

RLmin is then at least 1.3 ZR

Note	*The minimum relay setting for α is 90° as this defines the largest size of the characteristic, a circle.*

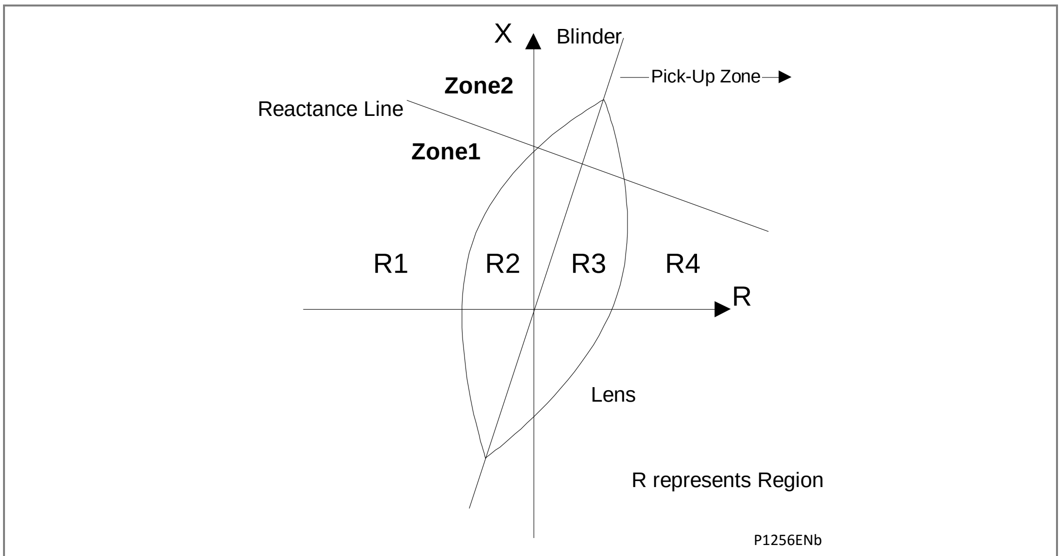


Figure 54 - Pole slipping protection using blinder and lenticular characteristic

Reactance Setting

The value of Zc

The value of Zc determines the distance of the reactance line from the origin. The reactance line provides a means of discrimination of the pole slipping within the generator or power swing within the HV power system. It should be set to encompass the step-up transformer and generator reactance with sufficient margin.

Pole slipping counters

Counters are available for both Zone1 and Zone2 to count the number of pole slip cycles before the trip signal is issued. A user-settable reset timer is available to reset the counters when the pole slipping condition is cleared by other relays in the system.

Timers T1 and T2

During a pole slip the impedance locus traverses across the lens spending at least time T1 in region 2 and time T2 in region 3, see Figure 54. From simulation testing it has been proved that pole slips up to 10 Hz can be detected with an angle α setting of 120° and time settings of 15 ms for T1 and T2. Therefore, it is recommended that T1 and T2 be set to 15 ms.

Reset timer

The reset time should be set longer than the maximum expected time for the machine to go through the set number of pole slips for zone1 or zone2. The reset time is required to reset the counters for pole slips that are cleared by external protection. For example if the Z2 counter is set to operate after 2 pole slips in the power system and after a count of 1 the condition is cleared by other protection in the system the counters will need to be reset to zero.

Pole slip mode

When a generator is out of step with the system, the impedance locus is expected to traverse from right to left across the lens and the blinder. However, if the generator is running as a motor, as in the pumping mode of a pump storage generator, the impedance locus is expected to swing from the left to the right. A pole slip mode setting is provided to determine whether the protection operates in a generating mode or in a motoring mode or both.

For a pump storage generator, its operation can switch from generating mode to motoring mode and vice versa. Therefore, a facility is provided for the protection to detect the normal running mode of the machine, generating or motoring and to perform pole slipping detection in either mode. This facility is enabled when the pole slip mode setting is set to both.

Also, when a generator is running at low load, <30% load, due to the presence of heavy system damping during a fault the generator can slow down and result in a motor like slip (negative slip). To detect pole slips for low load and normal load conditions then the pole slip mode should be set to both.

2.28.6.1 Pole Slipping Setting Examples

The impedances in the P343/P344/P345 can be set in terms of primary or secondary quantities, however, for simplicity all the impedance values used in the examples are in primary quantities.

2.28.6.2 Example Calculation

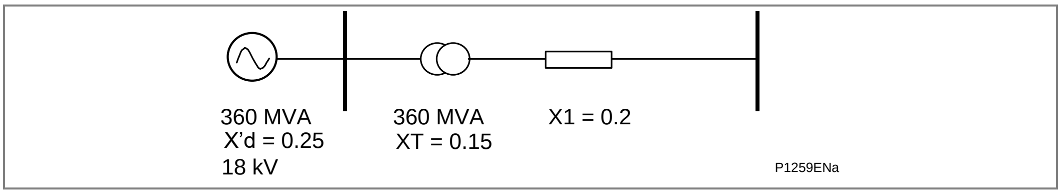


Figure 55 - Example system configuration

Data of the generator and step up transformer:

Base power	Pn	=	360 MVA
Base voltage	Vn	=	18000 kV
Min. load resistance	RLmin	=	0.77 Ω
System impedance angle	≥ 80°		
Generator impedance	0.25 pu		
Transformer impedance	0.15 pu		
System impedance	0.2 pu		

The location of the pole slipping relay is at the generator terminals. The direction of ZA and Zc is towards the step up transformer and the rest of the system. The reactance line is required to distinguish between power swings with electrical centers within the generator/transformer zone and those outside.

The base impedance is:

Zbase = Vn2/Pn = 182/360 = 0.9 Ω

ZA = (XT + X1) Zbase = (0.15+0.2) x 0.9 = 0.315 Ω

ZB = 2X'd x Zbase = 2 x 0.25 x 0.9 = 0.45 Ω

Zc is set to 90% of the transformer reactance

Zc = 0.9 x (XT) Zbase = 0.9 x 0.15 x 0.9 = 0.122 Ω

The minimum suitable angle α which defines the lens limit in relation to the minimum load resistance is:

αmin = 180° – 2 x tan-1 (1.54 x RLmin / (ZA + ZB))

αmin = 180° – 2 x tan-1 (1.54 x 0.77 / (0.315 + 0.45))

αmin = 65.7°

The minimum setting for α on the relay is 90° so this is the setting used.

T1 and T2 are set to 15 ms and θ is set to the system impedance angle of 80°.

2.29 Generator Thermal Overload Protection (49G)

2.29.1 Introduction

Overloads can result in stator temperature rises which exceed the thermal limit of the winding insulation. Empirical results suggest that the life of insulation is approximately halved for each 10°C rise in temperature above the rated value. However, the life of insulation is not wholly dependent on the rise in temperature but on the time the insulation is maintained at this elevated temperature. Due to the relatively large heat storage capacity of an electrical machine, infrequent overloads of short duration may not damage the machine. However, sustained overloads of a few percent may result in premature ageing and failure of insulation.

The physical and electrical complexity of generator construction result in a complex thermal relationship. It is not possible to create an accurate mathematical model of the true thermal characteristics of the machine.

However, if a generator is considered to be a homogeneous body, developing heat internally at a constant rate and dissipating heat at a rate directly proportional to its temperature rise, it can be shown that the temperature at any instant is given by a time-current thermal replica characteristic.

As previously stated it is an oversimplification to regard a generator as an homogeneous body. The temperature rise of different parts or even of various points in the same part may be very uneven. However, it is reasonable to consider that the current-time relationship follows an inverse characteristic. A more accurate representation of the thermal state of the machine can be obtained through the use of Temperature Monitoring Devices (RTDs) which target specific areas. Also, for short time overloads the application of RTDs and overcurrent protection can provide better protection. The thermal model does not compensate for the effects of ambient temperature change. So if there is an unusually high ambient temperature or if the machine cooling is blocked RTDs will also provide better protection.

2.29.2 Generator Thermal Replica

The P342/P343/P344/P345 relay models the time-current thermal characteristic of a generator by internally generating a thermal replica of the machine.

The positive and negative sequence components of the generator current are measured independently and are combined together to form an equivalent current, I_{eq}, which is supplied to the replica circuit. The heating effect in the thermal replica is produced by $I_{eq}2$ and therefore takes into account the heating effect due to both positive and negative sequence components of current.

Unbalanced phase currents will cause additional rotor heating that may not be accounted for by some thermal protection relays based on the measured current only. Unbalanced loading results in the flow of positive and negative sequence current components. Load unbalance can arise as a result of single-phase loading, non-linear loads (involving power electronics or arc furnaces, etc.), uncleared or repetitive asymmetric faults, fuse operation, single-pole tripping and reclosing on transmission systems, broken overhead line conductors and asymmetric failures of switching devices. Any negative phase sequence component of stator current will set up a reverse-rotating component of stator flux that passes the rotor at twice synchronous speed. Such a flux component will induce double frequency eddy currents in the rotor, which can cause overheating of the rotor body, main rotor windings, damper windings etc. This extra heating is not accounted for in the thermal limit curves supplied by the generator manufacturer as these curves assume positive sequence currents only that come from a perfectly balanced supply and generator design. The P34x & P391 generator thermal model may be biased to reflect the additional heating that is caused by negative sequence current when the machine is running. This biasing is done by creating an equivalent heating current rather than simply using the phase current. The M factor is a constant that relates negative sequence rotor resistance to positive sequence rotor resistance. If an M factor of 0 is used the unbalance biasing is disabled and the overload curve will time out against the measured generator positive sequence current. Note, the P34x & P391 also includes a negative sequence overcurrent protection function based on I_2^2t specifically for thermal protection of the rotor.

The equivalent current for operation of the overload protection is in accordance with the following expression:

$I_{eq} = \sqrt{(I_1^2 + MI_2^2)}$

Where:

I1 = Positive sequence current

I2 = Negative sequence current

M = A user settable constant proportional to the thermal capacity of the machine

As previously described, the temperature of a generator will rise exponentially with increasing current. Similarly, when the current decreases, the temperature also decreases in a similar manner. Therefore, in order to achieve close sustained overload protection, the P342/P343/P344/P345 relay incorporates a wide range of thermal time constants for heating and cooling.

Furthermore, the thermal withstand capability of the generator is affected by heating in the winding prior to the overload. The thermal replica is designed to take account the extremes of zero pre-fault current, known as the 'cold' condition and the full rated pre-fault current, known as the 'hot' condition. With no pre-fault current the relay will be operating on the 'cold curve'. When a generator is or has been running at full load prior to an overload the 'hot curve' is applicable. Therefore, during normal operation the relay will be operating between these two limits.

2.29.3 Setting Guidelines

The current setting is calculated as:

Thermal Trip = Permissible continuous loading of the plant item/CT ratio.

The heating thermal time constant should be chosen so that the overload curve is always below the thermal limits provided by the manufacturer. This will ensure that the machine is tripped before the thermal limit is reached.

The relay setting, T-heating, is in minutes.

The cooling thermal time constant should be provided by the manufacturer. However, unless otherwise specified, the cooling time constant, T-cooling, setting should be set equal to the main heating time constant setting, T-heating. The cooling time constant is applied when the machine is running and the load current is decreasing. It is therefore practical to assume the cooling time constant is similar to the heating time constant if information is not available from the manufacturer. When the machine is not turning the machine will normally cool significantly slower than when the rotor is turning. The relay setting, T-cooling, is in minutes.

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. The thermal alarm could also be used to prevent restarting of the generator until the alarm level resets. For this application a typical setting may be 20%.

The M Factor is used to increase the influence of negative sequence current on the thermal replica protection due to unbalanced currents. If it is required to account for the heating effect of unbalanced currents then this factor should be set equal to the ratio of negative phase sequence rotor resistance to positive sequence rotor resistance at rated speed. When an exact setting can not be calculated a setting of 3 should be used. This is a typical setting and will suffice for the majority of applications. If an M factor of 0 is used the unbalance biasing is disabled and the overload curve will time out against the measured generator positive sequence current.

Note	*The extra heating caused by unbalanced phase currents is not accounted for in the thermal limit curves supplied by the generator manufacturer as these curves assume positive sequence currents only that come from a perfectly balanced supply and generator design, so the default setting is 0.*

2.30 Transformer Thermal Overload Protection (49T)

Transformer overheating can be caused due to failures of the cooling system, external faults that are not cleared promptly, overload and abnormal system conditions. These abnormal conditions include low frequency, high voltage, non-sinusoidal load current, or phase-voltage unbalance.

Overheating shortens the life of the transformer insulation in proportion to the duration and magnitude of the high temperature. Overheating can generate gases that could result in electrical failure. Furthermore, excessive temperature may result in an immediate insulation failure. Also, the transformer coolant may be heated above its flash temperature, therefore a fire can be caused.

Results suggest that the life of insulation is approximately halved for each 10°C rise in temperature above the rated value. However, the life of insulation is not wholly dependent on the rise in temperature but on the time the insulation is maintained at this elevated temperature. Due to the relatively large heat storage capacity of a transformer, infrequent overloads of short duration may not damage it. However, sustained overloads of a few percent may result in premature ageing and failure of insulation.

The thermal overload protection in the P34x & P391 is based on IEEE Standard C57.91-1995. Thermal overload trip can be based on hot spot temperature, Θ_H, or top oil temperature, Θ_{TO}. Top oil temperature can be calculated or can be measured directly when either CLIO or RTD are available. Hot spot temperature is only calculated.

It is important to consider ambient temperature to determine the load capability of a transformer. The ambient temperature is the temperature of the air in contact with the transformer’s radiators. To determine the operating temperature, the temperature rise due to load is added to the ambient temperature. IEEE Standard C57.91-1995 states that transformer ratings are based on 24-hour average ambient temperature of 30°C. If the ambient temperature can be measured, then it should be averaged over a 24 hour period. In the P34x & P391 relays, the ambient temperature, Θ_A, can be measured directly or an average value can be set by the user.

The simplest application of overload protection employs I^2t characteristic. Time constants such as the winding time constant at hot spot location, τ_W, and top oil rise time constant, τ_{TO}, are set, so that the thermal model can follow the correct exponential heating and cooling profile, replicating the winding hotspot temperature. Transformer loads are becoming increasingly non-linear; hence, the P34x uses rms current values to replicate the winding hotspot temperature.

2.30.1 Setting Guidelines

Table 10, Table 11 and Table 12 are examples of the thermal data given by the transformer manufacturer. This data is required to set the thermal overload function.

Thermal characteristic 735 MVA 300 kV +7% to -18% / 23 kV ODWF cooled generator transformer	
No load losses (core losses)	340 kW
Load losses at nominal tap	1580 kW
Load losses at maximum current tap	1963 kW
Oil time constant	2.15 hr
Oil exponent	1.0
Top oil rise over ambient temperature at rated load	33.4 K
Winding time constant at hot spot location	14 mins
Winding hottest spot rise over top oil temperature at rated load	30.2 K
Winding exponent	2.0

Table 10 - Thermal characteristic MVA 300 kV +7% to -18% / 23 kV ODWF cooled generator transformer

Note	*OD (oil directed) indicates that oil from heat exchangers (radiators) is forced to flow through the windings. WF states that the oil is externally cooled by pumped water.*

Thermal characteristic 600 MVA 432/23.5 kV ODWF cooled generator transformer	
No load losses (core losses)	237 kW
Load losses at nominal tap	1423 kW
Load losses at maximum current tap	1676 kW
Oil time constant	2.2 hr
Oil exponent	1.0
Top oil rise over ambient temperature at rated load	46.6 K
Winding time constant at hot spot location	9 mins
Winding hottest spot rise over top oil temperature at rated load	33.1K
Winding exponent	2.0

Table 11 - Thermal characteristic 600 MVA 432/23.5 kV ODWF cooled generator transformer

Thermal characteristic IEC 60354 figures based on medium-large power transformers OD cooled	
Oil time constant	1.5 hr
Oil exponent	1.0
Top oil rise over ambient temperature at rated load	49 K
Winding time constant at hot spot location	5-10 mins
Winding hottest spot rise over top oil temperature at rated load	29 K
Winding exponent	2.0

Table 12 - Thermal characteristic IEC 60354 figures based on medium-large power transformers OD cooled

The monitor winding can be set either to HV, LV, or biased current. It is recommended to set it to biased current so an overall thermal condition of the transformer is provided. The ambient temperature can be set to average (average ambient temperatures covers 24 hour time periods), or it can be measured directly using a CLI or RTD input. Top oil temperature may be set as calculated or measured. IB is the load in pu, and it is recommended to set it at rated load, of 1.0 pu. The following parameters should be provided by the transformer manufacturer:

- The ratio of load loss at rated load to no load loss (Rated NoLoadLoss). For example, if the no load losses are 340 kW and load losses at rated are 1580 kW, the rated NoLoadLoss is 1580/340 = 4.6.

The losses in a transformer are shown in Figure 56:

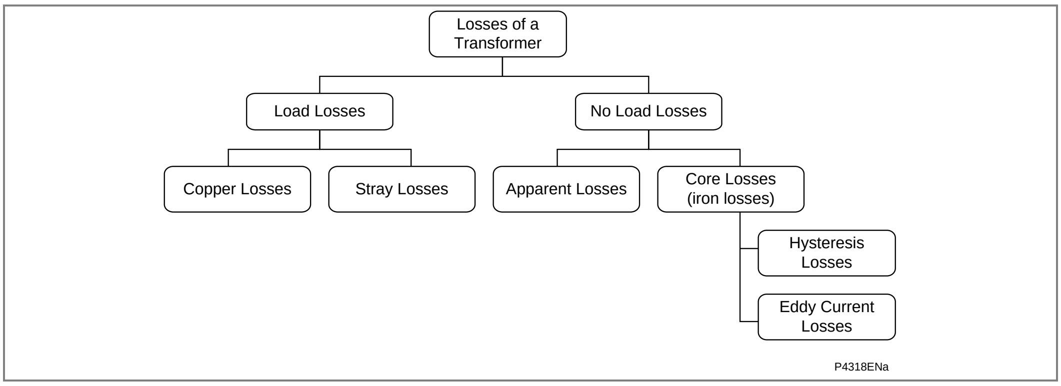


Figure 56 - Transformer losses

No-load losses are mainly iron losses. The loss that is due to the magnetizing current in the primary winding is called the apparent loss. The flow of the magnetizing current through the resistance of the winding does create a real I^2R loss and voltage drop, although both are generally quite small. Time-varying fluxes produce losses in ferromagnetic materials, known as core losses. These iron losses are divided into hysteresis losses and eddy-current losses.

The sum of copper losses and the stray losses is called the load losses. Copper losses are due to the flow of load currents through the primary and secondary windings. They are equal to I^2R, and they heat up the wires and cause voltage drops. Stray losses are due to the stray capacitance and leakage inductance. Stray capacitance exists between turns, between one winding and another, and between windings and the core.

- Winding hottest-spot rise over top oil at rated load (Hot Spot overtop)
- Top oil rise over ambient temperature at rated load (Top Oil overamb). It can also be determined by actual test per IEEE Std. C57.12.90-1993.
- Winding exponent (Winding exp m) and oil exponent (Oil exp n)

As indicated in the IEEE Std. C57.91-1995, the following are suggested winding and oil exponents.

Type of cooling	m (winding exponent)	n (oil exponent)
OA	0.8	0.8
FA	0.8	0.9
Non-directed FOA or FOW	0.8	0.9
Directed FOA or FOW	1.0	1.0

Table 13 - IEEE Std C57.91-1995 winding and oil exponents

These exponents are empirically derived and are required to calculate the variation of $\Delta\Theta_H$ and $\Delta\Theta_{TO}$ with load changes. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and off viscosity with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load.

The Cooling Mode setting - Natural, Forced Air, Forced Oil, Forced Air Oil, Select via PSL specifies which kind of cooling mode is used to cool the transformer. If Select Via PSL then DDB inputs (650 Frcd Air Cool and 651 Frcd Oil Cool) can be used to select the cooling mode Winding exp m and Oil exp n settings. If DDB 650 = 1 then cooling mode is Forced Air Cooling, if DDB 651 = 1 then cooling mode is Forced Oil Cooling, if DDB 650 and 651 = 1 then cooling mode is Forced Air Oil Cooling, if DDB 650 and 651 = 0 then cooling mode is Natural Cooling.

- Winding time constant at hot spot location (Hot spot rise co). It may also be estimated from the resistance cooling curve during thermal tests.
- Oil time constant (Top oil rise co)

The P34x has up to three hot spot stages and up to three top oil stages. The tripping signal, Top Oil T>x Trip, is asserted when the top oil (measured or calculated) temperature is above the setting, Top Oil>x Set, and the time delay, tTop Oil>x Set has elapsed. Also, the tripping signal, Hot Spot>x Trip, is asserted when the hottest-spot (calculated only) temperature is above the setting, Hot Spot>x Set, and the time delay, tHot Spot>x Set has elapsed.

When setting the hot spot and top oil stages take into consideration the suggested temperature limits (IEEE Std. C57.91-1995):

Suggested limits of temperature for loading above nameplate distribution transformers with 65°C rise	
Top oil temperature	120°C
Hot spot conductor temperature	200°C
Suggested limits of temperature for loading above nameplate power transformers with 65°C rise (refer to IEEE Std. C57.91-1995 to consider the four types of loading)	
Top oil temperature	110°C

Suggested limits of temperature for loading above nameplate distribution transformers with 65°C rise	
Hot spot conductor temperature	180°C

Table 14 - Suggested limits of temperature for loading above nameplate distribution transformers with 65°C rise

2.31 Loss of Life

As stated in IEEE Std. C57.91-1995, aging of insulation is a time function of temperature, moisture and oxygen content. The moisture and oxygen contributions to insulation deterioration are minimized due to modern oil preservation systems. Therefore temperature is the key parameter in insulation ageing. Temperature distribution is not uniform; the part with the highest temperature undergoes the greatest deterioration. Therefore the hottest spot temperature is considered in loss of life calculations.

2.31.1 Setting Guidelines

Set the life hours at reference hottest spot temperature. According to IEEE Std. C57.91-1995, the normal insulation life at the reference temperature in hours or years must be arbitrarily defined. The following table extracted from IEEE Std. C57.91-1995 gives values of normal insulation life for a well-dried, oxygen-free 65°C average winding temperature rise insulation system at the reference temperature of 110°C.

Basis	Normal insulation life	
	Hours	Years
50% retained tensile strength of insulation (former IEEE Std C57.92-1981 criterion)	65000	7.42
25% retained tensile strength of insulation	135000	15.41
200 retained degree of polymerization in insulation	150000	17.12
Interpretation of distribution transformer functional life test data (former IEEE Std. C57.91-1981)	180000	20.55
NOTES: Tensile strength or degree of polymerization (D.P.) retention values were determined by sealed tube aging on well-dried insulation samples in oxygen-free oil. Refer to I.2 in annex I of the IEEE Std. C57.91-1995 for discussion of the effect of higher values of water and oxygen and also for the discussion on the basis given above.		

Table 15 - Normal insulation life

The Designed HS temp should be set to 110°C if the transformer is rated 65°C average winding rise. If the transformer is rated 55°C average winding rise, set the Designed HS temp to 95°C.

As recommended by IEEE Std. C57.91-1995, the Constant B Set should be set to 15000 based on modern experimental data.

If the ageing acceleration factor calculated by the relay is greater than the setting FAA> Set and the time delay tFAA> Set has elapsed, the FAA alarm (DDB 479) would be activated.

If the loss of life calculated by the relay is greater than the setting LOL>1 Set and the time delay tLOL> Set has elapsed, the LOL alarm (DDB 480) would be activated.

The following is an example on how to set the loss of life function. Consider a new 65°C average winding rise rated transformer whose life hours at designed hottest spot temperature is 180,000 hrs. As a result, Life Hours at HS is set to 180,000, and the Designed HS temp is set to 110.0°C. The Constant B Set is 15,000 as recommended by IEEE from experimental data. The aging acceleration factor takes into consideration the constant B and the hottest spot temperature calculated by the thermal function. For a distribution transformer, IEEE suggests 200°C as the limit for the hottest spot temperature (refer to the thermal overload function to determine the hottest spot temperature for a power transformer). The aging acceleration factor alarm may be asserted when 70% of the 200°C is reached. The aging acceleration factor is calculated as follows:

$$FAA = e^{\left[\frac{B}{383} - \frac{B}{hottest - spot - tempt + 273}\right]} = e^{\left[\frac{B}{383} - \frac{B}{0.7 \times 200 + 273}\right]} = 17.2$$

Therefore FAA>set is 17.2. The tFAA> Set may be set to 10.00 min. The LOL>1 Set may be set to 115,000 hrs, if it is considered that the transformer has 65,000 hrs left (Life Hours at HS – hours left = 180,000 – 65,000 = 115,000 hrs). The tLOL> Set may be set to 10.00 min. Finally the Reset Life Hours setting determines the value of the LOL measurement once the Reset LOL command is executed. The default value is zero because considering a new transformer, after testing the thermal function in the P34x, the LOL measurement should be reset to zero.

Certain tests should be performed to determine the age of an old transformer. Advice from the transformer manufacturer should be requested.

2.32 Circuit Breaker Failure Protection (50BF)

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 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, Breaker Failure Protection (CBF) will operate.

CBF operation can be used to back-trip 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.

2.32.1 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 on 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. Therefore 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 circuit breaker fail 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 on 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.

2.32.1.1 Breaker Fail Timer Settings

Typical timer settings to use are as follows:

CB fail reset mechanism	tBF time delay	Typical delay for 2½ cycle circuit breaker
Initiating element reset	CB interrupting time + element reset time (max.) + error in tBF timer + safety margin	50 + 50 + 10 + 50 = 160 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 operating time	50 + 12 + 50 = 112 ms

Table 16 - CB fail typical timer settings

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.*

2.32.2 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, with 5% In common for generator circuit breaker CBF.

The sensitive earth fault protection (SEF) and standby earth fault (SBEF) undercurrent elements must be set less than the respective trip setting, typically as follows:

ISEF< = (ISEF> trip)/2

IN< = (IN> trip)/2

For generator applications the undercurrent elements should be measuring current from CTs on the terminal side of the generator. This is because for an internal fault on the generator after the CB has tripped the generator will still be supplying some fault current which will be seen by undercurrent elements measuring current from CTs on the neutral side of the generator. This could therefore give false indication of a breaker fail condition.

The voltage dependent overcurrent protection and underimpedance protection used for back-up protection of system faults are usually connected to the neutral side CTs so that the generator is in the zone of protection. These protection functions use the IA, IB, IC current inputs in the P343/P344/P345. Therefore, if the IA, IB, IC inputs are connected to neutral side CTs then the IA-2, IB-2, IC-2 inputs should be selected for the undercurrent elements using the setting I< Current Input - IA-1, IB-1, IC-1/IA-2, IB-2, IC-2.

2.33 Breaker Flashover Protection

Prior to generator synchronization, or just following generator tripping, where the protected generator could be slipping with respect to a power system, it is possible to establish at least twice rated phase-neutral voltage across the generator circuit breaker. An even higher voltage might briefly be established just after generator tripping for prime mover failure, where the pre-failure level of excitation might be maintained until AVR action takes place. Whilst generator circuit breakers must be designed to handle such situations, the probability of breaker interrupter breakdown or breakdown of open terminal switch gear insulators is increased and such failures have occurred.

This mode of breaker failure is most likely to occur on one phase initially and can be detected by a neutral current measuring element. If the generator is directly connected to the power system, the second stage of stator earth fault protection (IN>2...) could be applied as an instantaneous element by setting the time delay IN>2 TimeDelay to 0 s, to quickly detect the flashover. To prevent loss of co-ordination this stage must be blocked when the circuit breaker is closed. This can be programmed by correct configuration of the programmable scheme logic and can be integrated into the circuit breaker fail logic, as shown in Figure 57.

Where the machine is connected to the system via a step-up transformer a similar scheme can be arranged. The P34x & P391 relay standby earth fault protection element can be connected to measure the transformer HV earth fault current to provide the breaker flashover protection, via suitable scheme logic. The machine earth fault protection can be provided by the P34x & P391 sensitive earth fault protection element, as shown in Figure 58.

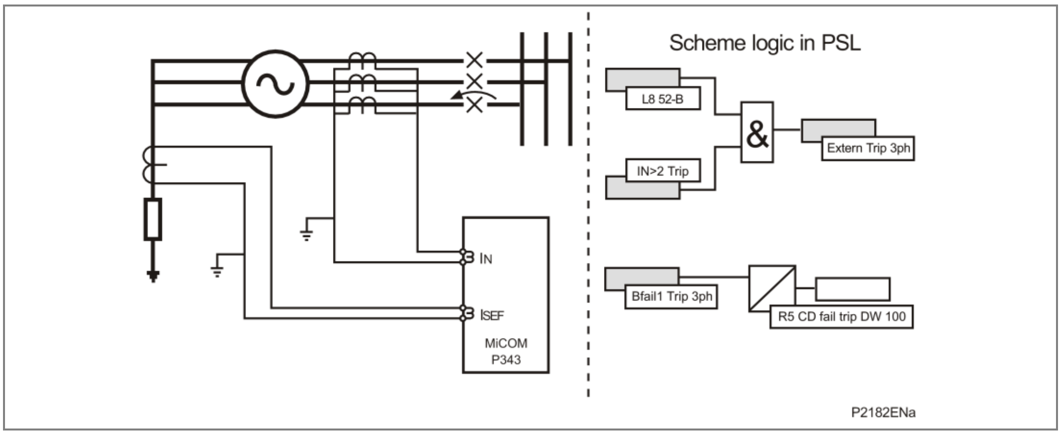


Figure 57 - Breaker flashover protection for directly connected machine

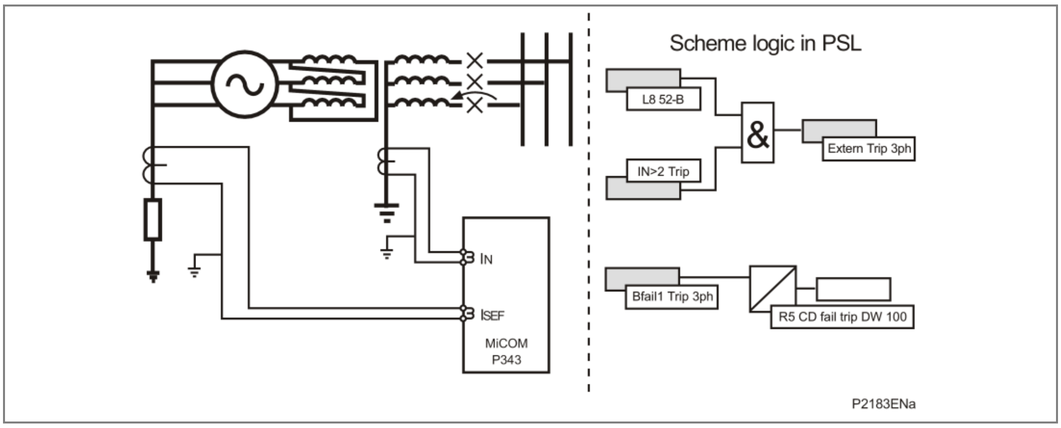


Figure 58 - Breaker flashover protection for indirectly connected machine

2.34 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 therefore 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 59 and Figure 60.

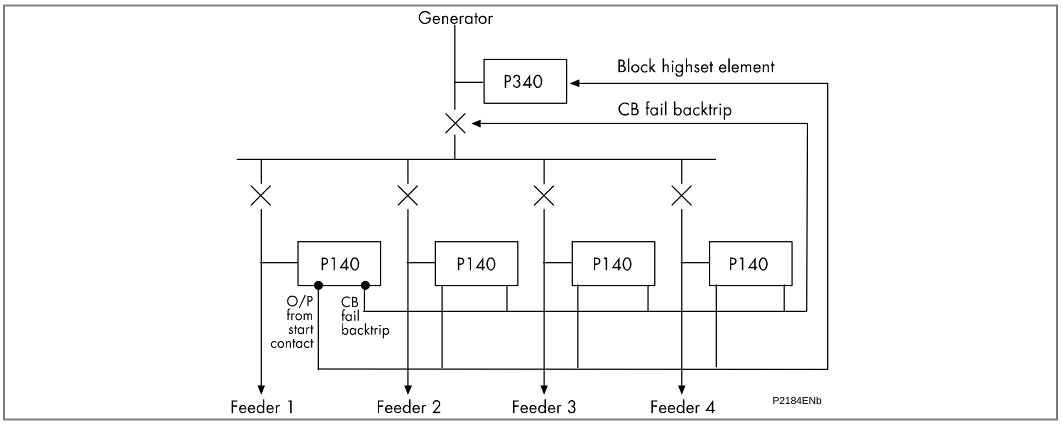


Figure 59 - Simple busbar blocking scheme (single incomer)

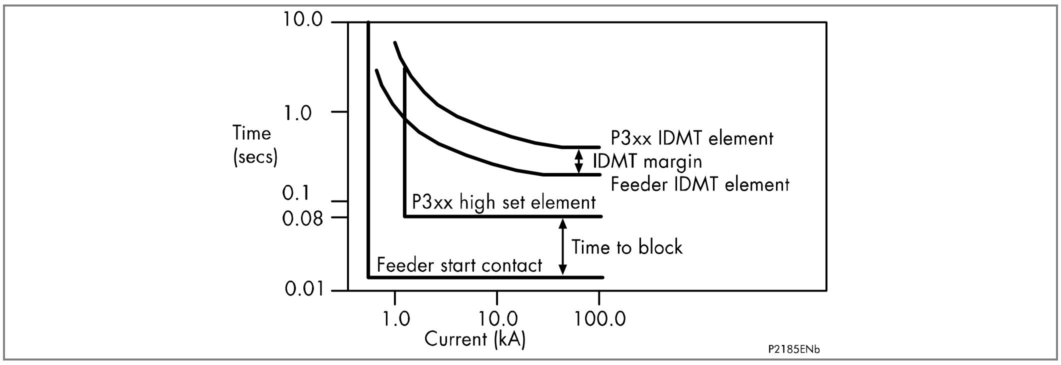


Figure 60 - Simple busbar blocking scheme (single incomer)

The P140/P34x & P391 relays have start outputs available from each stage of each of the overcurrent and earth fault elements, including sensitive earth fault. 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.

The P34x & P391 relays provide a 50 V field supply for powering the opto-inputs. Hence, in the unlikely event of the failure of this supply, blocking of that relay would not be possible. For this reason, the field supply is supervised and if a failure is detected, it is possible, via the relays programmable scheme logic, to provide an output alarm contact.

This contact can then be used to signal an alarm within the substation. Alternatively, the relays scheme logic could be arranged to block any of the overcurrent/earth fault stages that would operate non-discriminatively due to the blocking signal failure.

For further guidance on the use of blocked overcurrent schemes refer to Schneider Electric.

2.35 Current Loop Inputs and Outputs

2.35.1 Current Loop Inputs

Four analog (or current loop) inputs are provided for transducers with ranges of 0 - 1 mA, 0 - 10 mA, 0 - 20 mA or 4 - 20 mA. The analog inputs can be used for various transducers such as vibration monitors, tachometers and pressure transducers. Associated with each input there are two protection stages, one for alarm and one for trip. Each stage can be individually enabled or disabled and each stage has a definite time delay setting. The Alarm and Trip stages can be set for operation when the input value falls below the Alarm/Trip threshold Under or when the input current is above the input value Over.

Power-on diagnostics and continuous self-checking are provided for the hardware associated with the current loop inputs.

For the 4 - 20 mA input range, a current level below 4 mA indicates that there is a fault with the transducer or the wiring. An instantaneous under current alarm element is available, with a setting range from 0 to 4 mA. This element controls an output signal (CLI1/2/3/4 I< Fail Alm., DDB 390-393) which can be mapped to a user defined alarm if required.

2.35.2 Setting Guidelines for Current Loop Inputs

For each analog input, the user can define the following:

- The current input range: 0 - 1 mA, 0 - 10 mA, 0 - 20 mA, 4 - 20 mA
- The analog input function and unit, this is in the form of a 16-character input label
- Analog input minimum value (setting range from –9999 to 9999)
- Analog input maximum value (setting range from –9999 to 9999)
- Alarm threshold, range within the maximum and minimum set values
- Alarm function - over or under
- Alarm delay
- Trip threshold, range within maximum and minimum set values
- Trip function - over or under
- Trip delay

Each current loop input can be selected as Enabled or Disabled as can the Alarm and Trip stage of each of the current loop input. The Alarm and Trip stages can be set for operation when the input value falls below the Alarm/Trip threshold Under or when the input current is above the input value Over depending on the application. One of four types of analog inputs can be selected for transducers with ranges of 0 - 1 mA, 0 - 10 mA, 0 - 20 mA or 4 - 20 mA.

The Maximum and Minimum settings allow the user to enter the range of physical or electrical quantities measured by the transducer. The settings are unit-less; however, the user can enter the transducer function and the unit of the measurement using the 16-character user defined CLI Input Label. For example, if the analog input is used to monitor a power measuring transducer, the appropriate text could be “Active Power(MW)”.

The alarm and trip threshold settings should be set within the range of physical or electrical quantities defined by the user. The relay will convert the current input value into its corresponding transducer measuring value for the protection calculation.

For example if the CLI Minimum is –1000 and the CLI Maximum is 1000 for a 0 - 10 mA input, an input current of 10 mA is equivalent to a measurement value of 1000, 5 mA is 0 and 1 mA is –800. If the CLI Minimum is 1000 and the CLI Maximum is -1000 for a 0 - 10 mA input, an input current of 10 mA is equivalent to a measurement value of –1000, 5 mA is 0 and 1 mA is 800. These values are available for display in the CLIO Input 1/2/3/4 cells in the MEASUREMENTS 3 menu. The top line shows the CLI Input Label and the bottom line shows the measurement value.

2.35.3 Current Loop Outputs

Four analog current outputs are provided with ranges of 0 - 1 mA, 0 - 10 mA, 0 - 20 mA or 4 - 20 mA which can alleviate the need for separate transducers. These may be used to feed standard moving coil ammeters for analog indication of certain measured quantities or into a SCADA using an existing analog RTU.

The outputs can be assigned to any of the following relay measurements:

- Magnitudes of IA, IB, IC, IN, IN Derived, I Sensitive
- Magnitudes of I1, I2, I0
- IA RMS, IB RMS, IC RMS
- Magnitudes of VAB, VBC, VCA, VAN, VBN, VCN, VN Measured, VN Derived
- Magnitudes of V1, V2 and V0
- VAN RMS, VBN RMS, VCN RMS
- Frequency
- Single-phase active, reactive and apparent power, single-phase power factor
- Three-phase active, reactive and apparent power, single-phase power factor
- VN 3rd harmonic (P343/P344/P345 only)
- Stator thermal state
- Rotor (NPS) thermal state (P342/P343/P344/P345 only)
- RTD temperatures (P342/P343/P344/P345 only)
- Analog inputs

The user can set the measuring range for each analog output. The range limits are defined by the Maximum and Minimum settings. This allows the user to “zoom in” and monitor a restricted range of the measurements with the desired resolution. For voltage, current and power quantities, these settings can be set in either primary or secondary quantities, depending on the CLO1/2/3/4 Set Values - Primary/Secondary setting associated with each current loop output.

Power-on diagnostics and continuous self-checking are provided for the hardware associated with the current loop outputs.

2.35.4 Setting Guidelines for Current Loop Outputs

Each current loop output can be selected as Enabled or Disabled. One of four types of analog output can be selected for transducers with ranges of 0 - 1 mA, 0 - 10 mA, 0 - 20 mA or 4 - 20 mA. The 4 - 20 mA range is often used so that an output current is still present when the measured value falls to zero. This is to give a fail safe indication and may be used to distinguish between the analog transducer output becoming faulty and the measurement falling to zero.

The Maximum and Minimum settings allow the user to enter the measuring range for each analog output. The range, step size and unit corresponding to the selected parameter is shown in the table in the Operating chapter, *P34x & P391/EN OP*. This allows the user to “zoom in” and monitor a restricted range of the measurements with the desired resolution.

For voltage, current and power quantities, these settings can be set in either primary or secondary quantities, depending on the CLO1/2/3/4 Set Values - Primary/Secondary setting associated with each current loop output.

The relationship of the output current to the value of the measurand is of vital importance and needs careful consideration. Any receiving equipment must, of course, be used within its rating but, if possible, some kind of standard should be established.

One of the objectives must be to have the capability to monitor the voltage over a range of values, so an upper limit must be selected, typically 120%. However, this may lead to difficulties in scaling an instrument.

The same considerations apply to current transducers outputs and with added complexity to watt transducers outputs, where both the voltage and current transformer ratios must be taken into account.

Some of these difficulties do not need to be considered if the transducer is only feeding, for example, a SCADA outstation. Any equipment which can be programmed to apply a scaling factor to each input individually can accommodate most signals. The main consideration will be to ensure that the transducer is capable of providing a signal right up to the full-scale value of the input, that is, it does not saturate at the highest expected value of the measurand.

2.36 Rotor Earth Fault Protection (64R)

Rotor earth fault protection is used to detect earth faults in the excitation circuit of synchronous generators.

The field circuit of a synchronous generator, comprising the winding, the exciter and the field circuit breaker, is a DC circuit which is not normally earthed. If an earth fault occurs, no steady state fault current will flow and no damage will be incurred. If a second earth fault occurs at a separate point in the field system, this constitutes a winding short-circuit of the excitation circuit where part of the field winding is by-passed, and the current through the remaining portion may be increased.

The field current from a large machine can be high causing serious damage to the rotor and the exciter. If a large part of the field winding is short-circuited, the flux may result in an attracting force which is strong on one pole and weak on the opposite one. The result is an unbalanced force causing violent vibrations. This may damage the bearings or even displace the rotor which in turn may damage the stator.

After the first earth fault occurs, the risk of a second earth fault increases, since the first fault establishes an earthed reference for the voltage induced in the field by stator transients. These transients increase the stress to earth at other points in the field winding.

2.36.1 Setting Guidelines for Rotor Earth Fault Protection

The rotor earth resistance is measured using an external low frequency square wave injection, coupling and measurement unit, P391, connected to the rotor circuit. The measurement of the rotor resistance is passed to the P342/P343/P344/P345 via a current loop output (0-20 mA) on the P391 connected to one of the 4 current loop inputs (0-20 mA) on the P342/P343/P344/P345. The rotor earth fault protection is only available if the relay includes the CLIO hardware option. Two under resistance stages of definite time protection are available for alarm and trip.

The rotor earth fault protection element can be selected by setting the Rotor E/F cell in the Configuration column to Enabled.

The rotor earth fault protection uses one of the four current loop (transducer) inputs to provide the rotor resistance measured by the P391 injection, coupling and measuring unit. The current loop input used for rotor earth fault protection is selected using the setting CL I/P select – Current Loop CL1/CL2/CL3/CL4 in the Rotor EF menu settings.

The under resistance alarm (64R R<1 Alarm) and trip (64R R<2 Trip) stages can be independently enabled or disabled. The under resistance alarm threshold, 64R R<1 Alm Set, and trip threshold, 64R R<2 Trip Set must be set below the level of resistance present under normal conditions. This resistance can be determined by viewing the 64R R Fault cell in the MEASUREMENTS 3 menu. A typical value for the fault resistance alarm setting is 40 kΩ and the trip setting is 5 kΩ. These values can be changed depending on the insulation resistance and the coolant. Care must be taken to allow a sufficient margin between the setting value and the actual insulation resistance. As interference from the excitation system cannot be excluded, the setting for the warning stage can be finally established during primary tests.

During a generator start-up or during system transient conditions, intermittent earths can be produced by moisture or copper dusting, which could give nuisance operations, particularly if instantaneous operation is used. A time delay is recommended to avoid nuisance tripping. A time delay for the 64R R<1/2 elements can be set in the 64R R<1 Alm Dly, 64R R<2 Trip Dly cells. The default time delays, 1 s for trip and 10 s for the alarm, provide typical values. The set times are additional time delays not including the operating time of the protective function.

The Injection Frequency setting, 0.25 Hz / 0.5 Hz / 1 Hz must be set to match the frequency set on the P391 coupling unit which is selected with jumper links, see P391 connection diagrams for jumper link positions in the Installation Chapter, *P34x/EN IN*.

The R Compensation setting is used to compensate any resistance errors. The setting can be found during commissioning testing.

The P34x rotor earth fault protection does not discriminate between one point of insulation breakdown and multiple points of insulation breakdown. When a device such as a generator vibration detector is used for the detection of multiple points of insulation breakdown then the P34x & P391 can be used to alarm only and to trip under supervision of the vibration device. When a vibration detector is not used, it is recommended to trip from the P34x & P391 rotor earth fault protection for the first fault detected.

The P391 can be connected to a single end or to two ends of the field winding, see Installation section connection diagrams, *P34x & P391/EN IN*. The 2-end connection is recommended where possible as this connection provides more stable and steady measurements.

2.36.2 Redundant Rotor Earth Fault Protection

To provide redundant rotor earth fault protection one P391 can be connected to two P34x & P391 relays.

The P391 current loop output voltage was designed to drive 20 mA through a maximum load of 500 ohms but the input impedance of one P34x & P391 0-20 mA current loop input is 360 ohms. So the P391 can not directly drive two current loop inputs with the P391 current loop output.

However, this problem can be overcome by using a repeater between the P391 and P34x & P391 relays which provides 2 x 0-20 mA outputs. A repeater such as the PR 5104A from Omni Instruments, (http://www.omniinstruments.co.uk) has been tested and can be used for this type of application. The 5104A current input resistance is 10 ohms and each 0-20 mA output maximum load is 600 ohms.

Note	*For 1/0.6 mm lightweight cable (CSA 0.28 mm²) the cable resistance is 65 Ω/km so for this cable the maximum cable distance between the P391 and P34x can be approx. 1km, (maximum cable length (km) = 140/loop resistance 2Rl = 140/2x65 = 1.07 km). It is recommended that a screened cable earthed at one end is used to reduce interference.*

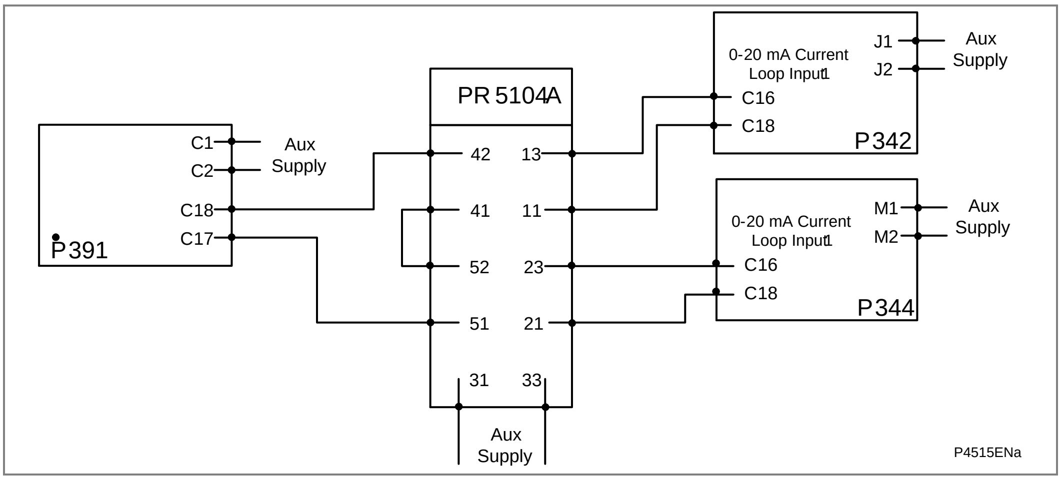


Figure 61 - Redundant rotor earth fault connection

3 APPLICATION OF NON-PROTECTION FUNCTIONS

3.1 Check Synchronization

3.1.1 Basic Principle

If a circuit breaker is closed when the generator 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 the connected generator and generator-transformer.

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 depend 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 an 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).

For generator applications before closing the CB the frequency and voltage from the machine is varied automatically or manually until the generator voltage is in synchronism with the power system voltage. A check synchronizing relay is used to check the generator voltage is in synchronism with the system voltage in terms of voltage magnitude, voltage difference, phase angle and slip frequency before the generator CB is allowed to close.

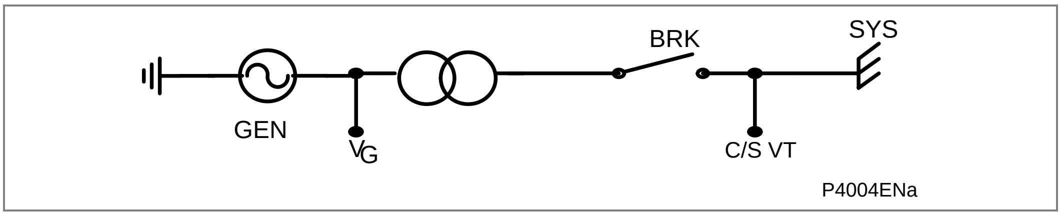


Figure 62 - Typical connection between system and generator-transformer unit

3.1.2 VT Selection

The P34x & P391 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 generator 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 -**

Gen/Bus setting in the **SYSTEM CONFIG** menu. This is required for the voltage monitors to correctly define the Live Gen/Dead Gen and Live Bus/Dead Bus DDBs.

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 **SYSTEM CONFIG** menu should be set to **A-N**, **B-N**, **C-N**, **A-B**, **B-C** or **C-A** as appropriate.

The P342/P343 uses the neutral voltage input, VNeutral, for the Check Synch VT and so the user can not use the check synchronizing and the measured neutral voltage (59N) protection (VN>3, VN>4) at the same time. However, the derived neutral voltage protection (VN>1, VN>2) from the 3 phase voltage input can still be used with the check synchronizing function.

The P344 uses the neutral voltage input, VN2, for the Check Synch VT and so the user can not use the check synchronizing and measured neutral voltage (59N) protection from VN2 (VN>5, VN>6) at the same time. However, the derived neutral voltage protection (VN>1, VN>2) from the 3 phase voltage input and the measured neutral voltage protection (VN>3, VN>4) from the VN1 voltage input can still be used with the check synchronizing function.

The P345 uses a dedicated V Check Sync voltage input for the Check Synch VT and so there are no restrictions in using the check synchronizing function and other protection functions in the relay.

3.1.3 Voltage and Phase Angle Correction

3.1.3.1 CS VT Ratio Correction

Differences in the busbar voltage and the generator voltage magnitude may be introduced by unmatched or slightly erroneous voltage transformer or step-up transformer ratios. These differences should be small, but they may be additive and therefore be significant. To compensate magnitude differences between the busbar voltage and the generator voltage the generator voltage can be adjusted by a multiplying factor, **C/S V Ratio Corr** to correct for any mismatch.

The voltage correction factor can be calculated as shown below:

$$\frac{TVR \times VTG}{VTB}$$

where

TVR = step-up transformer voltage ratio (HV nominal /LV nominal)

VTG = generator voltage transformer ratio (Main VT Primary/Main VT Sec'y)

VTB = busbar voltage transformer ratio (C/S VT Prim'y/C/S VT Sec'y)

For example,

IF TVR = 38.5 kV /10.5 kV, VTG = 10 kV/100 V, VTB = 35 kV/100 V AND Vgen = VGab, Vbus = VBab

Then, Vgen = 10500/100 = 105 V (secondary voltage), Vbus = 38500/350 = 110 V, and:

$$\textbf{C/S V Ratio Corr} = \frac{TVR \times VTG}{VTB} = 1.0476$$

So: Vgen' = Vgen x **C/S V Corr** = 110 V = Vbus

3.1.3.2 CS VT Vector Correction

If the generator CB is on the HV side the generator step-up transformer typically with the synch VT on the transformer HV side, the P34x & P391 uses the **Main VT Vect Grp** setting to compensate the phase shift between the generator VTs and the synch VT introduced by the transformer connections:

$$V_{gen,angle\_comp} = V_{gen} e^{jN30^{\circ}}$$

Here, N = Main VT Vector Group, N = 0, 1,…11.

The generator voltage, Vgen, compensated phase shift is $N \times 30^{\circ}$. In most cases, N is 1, 11 and 0, and the corresponding compensated phase shift is +30°, -30° (330°) and 0°. The vector group (N) is 0 for the Main VT and synch VT on the generator side of the transformer or if there is no step-up transformer.

For example, when the step-up transformer connection type is Yd11, the LV Clock Vector is at 11 o'clock, the connection and vector diagrams are as below. Usually, the Main VT is on the generator LV side of the transformer so the **Main VT Vect Grp** matches the vector group of the transformer, eg **Main VT Vect Grp** = 11 for a Yd11 transformer.

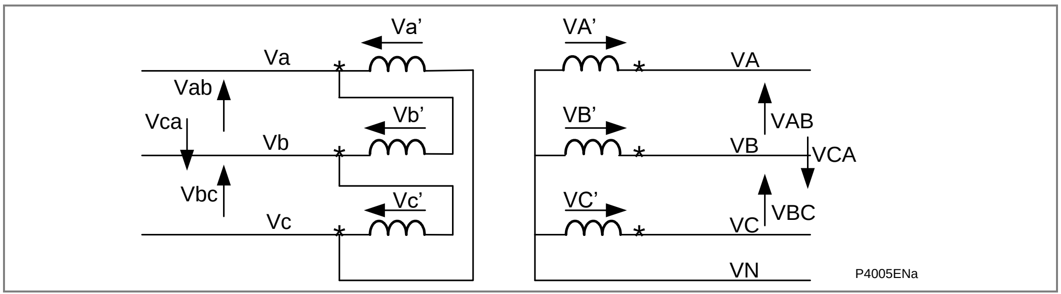


Figure 63 - Typical connection between system and generator-transformer unit Transformer connection

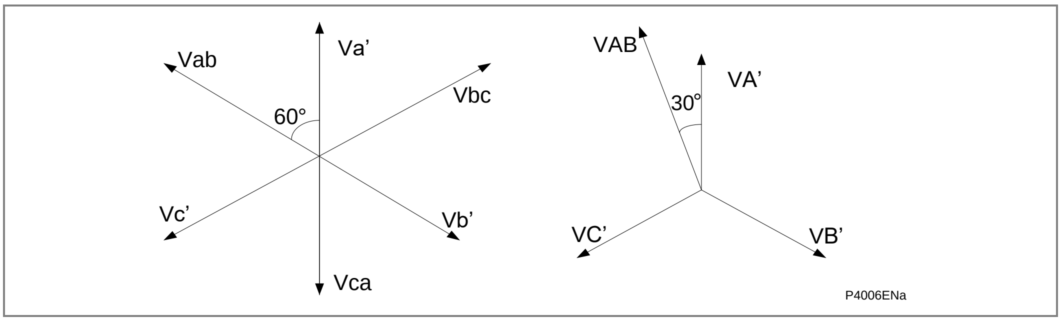


Figure 64 - Transformer vector diagram

It can been seen that, $Vab = Vb$, the vector Vab is forward to VAB 30º, so the compensated phase shift should be -30°, that is vector Vab should be rotated 30° clockwise, Main VT Vect Grp = 11, assuming Main VT is on transformer LV side.

3.1.4 Voltage Monitors

The P34x & P391 System Checks function includes voltage monitors to indicate if the generator and system busbar voltages are Live or Dead. The voltage monitor signals are not usually used for the closing logic of a generator CB, the check synch logic is generally only used for this application. The voltage monitor signals are typically used in feeder autoreclose applications where the first feeder CB to close may use the voltage monitor signals to check for Live Bus/Dead Line for example. The default settings are typical values, Dead = 0.2 Vn and Live = 0.5 Vn.

The voltage monitor DDBs, if required, are combined in the PSL to provide the manual CB close check synchronizing logic, eg Dead Line/Live Gen (The P34x & P391 does not include autoreclose logic). The DDBs are connected to the Man Check Synch DDB (1362) which provides an input to the CB control logic to indicate a manual check synchronizing condition is satisfied.

The voltage monitor signals can be useful in generator applications to give indication if the generator or system busbar voltages are Live or Dead or can be used with timers in the PSL to provide additional under/overvoltage protection.

When Vgen magnitude is > Live Voltage, the generator is taken as Live (DDB 1328, Live Gen)

When Vgen magnitude is < Dead Voltage, the generator is taken as Dead (DDB 1329, Dead Gen)

When Vbus magnitude is > Live Voltage, the busbar is taken as Live (DDB 1330, Live Bus)

When Vbus magnitude is < Dead Voltage, the busbar is taken as Dead (DDB 1331, Dead Bus)

3.1.5 Check Synchronization

The P34x & P391 System Checks function includes 2 check synchronization elements, Check Sync 1 and Check Sync 2. The check synch 1 OK (1332) and Check Synch 2 OK (1333) DDBs, if required, are used in the PSL to provide the manual CB close check synchronizing logic. The DDBs are connected to the Man Check Synch DDB (1362) which provides an input to the CB control logic to indicate a manual check synchronizing condition is satisfied.

Each check synch element checks that the generator frequency, voltage magnitude, and phase angle match the system frequency, voltage magnitude, and phase angle before allowing the generator breaker to be closed. Each element includes settings for the phase angle difference and slip frequency between the generator and system busbar voltages.

The P34x & P391 also includes independent under/overvoltage monitors for the generator and system side of the CB as well as a differential voltage monitor applicable to both the Check Sync 1 and 2 elements. The user can select a number of under/over/differential voltage check synchronizing blocking options using the setting **CS Voltage Block** – **None, V<, V>, Vdiff>, V< and V>, V< and Vdiff>, V> and Vdiff>, V< V> Vdiff>.**

3.1.5.1 Slip Control

The slip frequency used by Check Synch 1/2 can be calculated from the **CS1/2 Phase Angle** and **CS1/2 Slip Timer** settings as described below or can be measured directly from the frequency measurements, slip frequency = |Fgen-Fbus|. The user can select a number of slip frequency options using the settings **CS1 Slip Control** – **None, Timer Only, Frequency Only, Both** and **CS2 Slip Control** – **None, Timer, Frequency, Timer + Freq, Freq + CB Comp**.

If Slip Control by **Timer** or **Frequency + Timer**/**Both** is selected, the combination of **CS Phase Angle** and **CS Slip 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, for Check Sync 1 with **CS 1 Phase Angle** setting 30° and **CS 1 Slip 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 synchronism 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 **CS2 Phase Angle** setting 10° and **CS2 Slip 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 synchronism 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 < 0.1 s. For these situations, slip control by **Frequency** is recommended.

If **CS Slip Control** by **Frequency + Timer** (CS1) or **Both** (CS2) is selected, for an output to be given, the slip frequency must be less than BOTH the set **CS1/2 Slip Freq** value and the value determined by the **CS1/2 Phase Angle** and **CS1/2 Slip Timer** settings.

3.1.5.2 CB Closing Time Compensation

The **CS2 Slip Control** – **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, 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.

The equation below describes the relationship between the compensated angle δ_K and the lead time to CB closing t_K for the circuit breaker to close at the instant the slip angle is equal to the CS2 phase angle setting, assuming the slip frequency is constant.

$$\delta_{MEA} - CS2\,phaseangle = \delta_K = \Delta\omega \times t_K$$

$$t_K = \frac{\delta_{MEA} - CS2\,phaseangle}{\Delta\omega} = \frac{\delta_{MEA} - CS2\,phaseangle}{Slip.Freq. \times 360^o}$$

δ_{MEA} = Mea.Angle

$\Delta\omega$ = slip angle velocity

δ_K = compensated angle

t_K = lead time to CB close

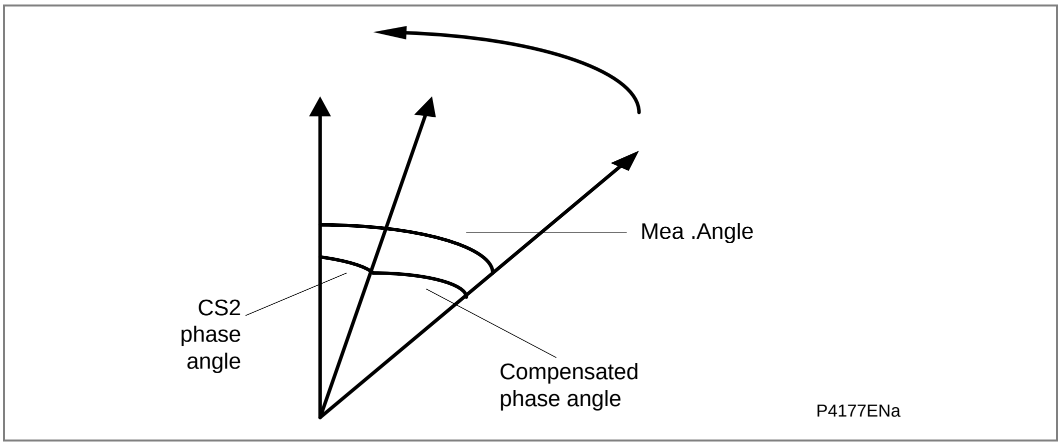


Figure 65 - Check synch. 2 phase angle diagram

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. When CS2 phase angle = 0, the breaker should be closed just when the voltages are in phase with each other.

The **CB Close Time** measurement is available in the **CB Condition** menu for the last CB close. The relay calculates the **CB Close Time** from the time the close command is given to the time the CB is closed as indicated by the 3 pole dead logic. The **CB close Time** measurement can be useful when setting the **CB Close Time** compensation setting in the **System Checks** menu.

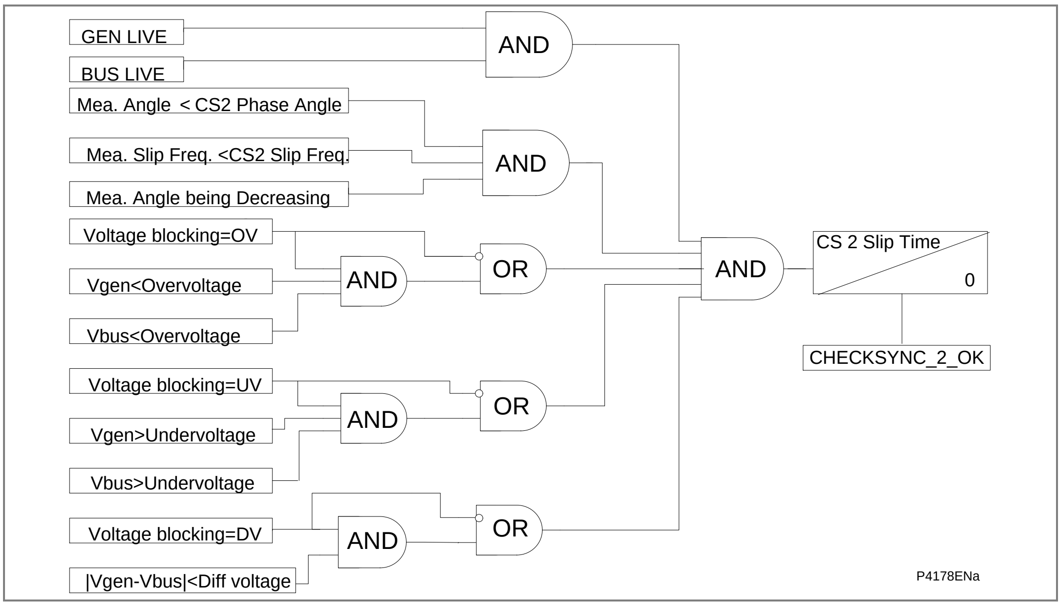


Figure 66 - Check synch. 2 functional diagram

3.1.5.3 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 synchronism 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 P34x can be configured to allow CB closure if either of the two conditions is detected.

For manual circuit breaker closing with synchronism 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 on 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.

3.1.5.4 Generator Check Synchronizing

For generator CB closing applications generally there is only one synchronism check element required and so Check Sync 1 or Check Sync 2 is used.

The Check Sync 2 element includes CB closing time compensation and unlike Check Sync 1, Check Sync 2 only permits closure for decreasing angles of slip.

There are several synchronizing methods that may be used to minimize the possibility of damaging a generator when closing the generator CB:

- Automatic synchronizing
- Semi-automatic synchronizing
- Manual synchronizing

Synchronizing check relays are often applied with all these schemes to supervise the closing of the CB.

To avoid damaging a generator during synchronizing, the generator manufacturer will generally provide synchronizing limits in terms of breaker closing angle and voltage matching. Typical limits are:

- Breaker closing angle: ±10 electrical degrees. The closing of the circuit breaker should ideally take place when the generator and the system are at or close to zero degrees phase angle with respect to each other. To accomplish this, the breaker should be set to close in advance of the phase angle coincidence taking into account the breaker closing time.
- Voltage matching: 0% to +5%. The voltage difference should be minimized and not exceed 5%. This aids in maintaining system stability by ensuring some VAR flow into the system. Additionally, if the generator voltage is excessively lower than the grid when the breaker is closed, sensitive reverse power relays may trip.
- Slip frequency: <0.067 Hz. The slip frequency should be minimized to the practical control/response limitations of the given prime mover. A large frequency difference causes rapid load pickup or excessive motoring of the machine. This could cause power swings on the system and mechanical torques on the machine. Additionally, if the machine is motored, sensitive reverse power relays may trip.

Slip frequency limits applied for certain machine types are based on the ruggedness of the turbine generator under consideration and the controllability of the turbine generator and MVA.

To prevent power flow from the system to the generator, some large steam turbine generators require that a low, positive slip be present when the generator breaker is closed. In contrast, Diesel generators may require that a zero or negative slip be present to unload the machine shaft and crank briefly when the generator breaker is closed. The DDBs CS1/2 Slipfeq>, CS1/2 Slipfeq<, CS Ang Rot ACW and CS Ang Rot CW can be used as interlocking signals to the ManCheck Synch DDB for these applications.

3.1.6 Frequency/Voltage Control

The DDBs, CS Vgen>Vbus, CS Vgen<Vbus, CS1 Fgen>Fbus, CS1 Fgen<Fbus, CS2 Fgen>Fbus and CS2 Fgen<Fbus can be used for simple frequency control and voltage control outputs or for indication purposes. Pulsed outputs can be achieved using PSL if required.

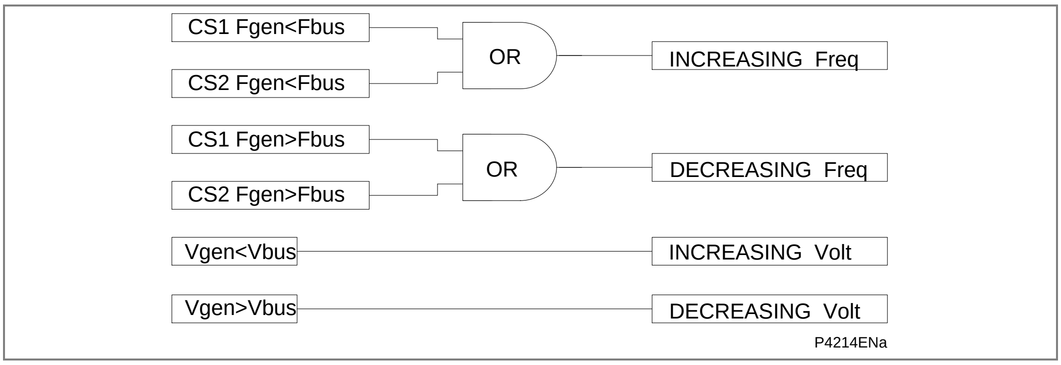


Figure 67 - Freq/Volt control functional diagram

3.2 VT Supervision

The Voltage Transformer Supervision (VTS) feature is used to detect failure of the ac voltage inputs to the relay. 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.

3.2.1 Setting the VT Supervision Element

The VTS Status setting Blocking/Indication determines whether these operations will occur on 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 overcurrent protection.

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) when the VTS Reset Mode is set to Manual. The second method is automatically when VTS Reset Mode is set to 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 240 ms.

The VTS I> Inhibit overcurrent setting is used to inhibit the voltage transformer supervision in the event of a loss of all 3 phase voltages caused by a close up 3 phase fault occurring on the system following closure of the CB to energize the line. 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.

This VTS I2> Inhibit NPS overcurrent setting is used to inhibit the voltage transformer supervision in the event of a fault occurring on the system with negative sequence current above this setting

The NPS current pick-up threshold must be set higher than the negative phase sequence 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 negative phase sequence current, and setting at least 20% above this figure.

3.3 CT Supervision

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, CTS1/2 Vn< Inhibit and the residual current setting, CTS1/2 In> set, should be set to avoid unwanted operation during healthy system conditions.

For example CTS1/2 Vn< Inhibit should be set to 120% of the maximum steady state residual voltage. The CTS1/2 In> set will typically be set below minimum load current. The time-delayed alarm, CTS1/2 Time Delay, is generally set to 5 seconds.

Where the magnitude of residual voltage during an earth fault is unpredictable, the element can be disabled to prevent a protection elements being blocked during fault conditions.

3.3.2 Setting the Differential CT Supervision Element

The positive sequence current in at least two current inputs exceeds the CTS I1 setting. The CTS I1 setting should be below the minimum load current of the protected object. Therefore, 10% of the rated current might be used.

The high set ratio of negative to positive sequence current, CTS I2/I1>2, should be set below the ratio of negative sequence to positive sequence current for the minimum unbalanced fault current. A typical setting of 40% might be used.

The low set ratio of negative to positive sequence current, CTS I2/I1> 1, should be set above the maximum load unbalance. 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. A 20% setting might be used.

If the following information is recorded by the relay during commissioning:

Ifull load = 500 A

I2 = 50 A

Therefore 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 CTS I2/I1>1 = 20%.

Since sensitive settings have been used a long time delay is necessary to ensure a true CT failure. A 60 second time delay setting may be typical.

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 (OCB's), 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 OCB's, the dielectric withstand of the oil generally decreases as a function of Σ I2t. 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 on 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

A circuit breaker may be rated to break fault current a set number of times before maintenance is required. However, successive circuit breaker operations in a short period of time may result in the need for increased maintenance. 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 Trip Circuit Supervision (TCS)

The trip circuit, in most protective schemes, extends beyond the IED 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) scheme variants are offered. Although there are no dedicated settings for TCS, in the MiCOM P24x / P34x / P443 / P445 / P446 / P54x / P547 / P64x / P746 / P841 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.

3.5.1 TCS Scheme 1

3.5.1.1 Scheme Description

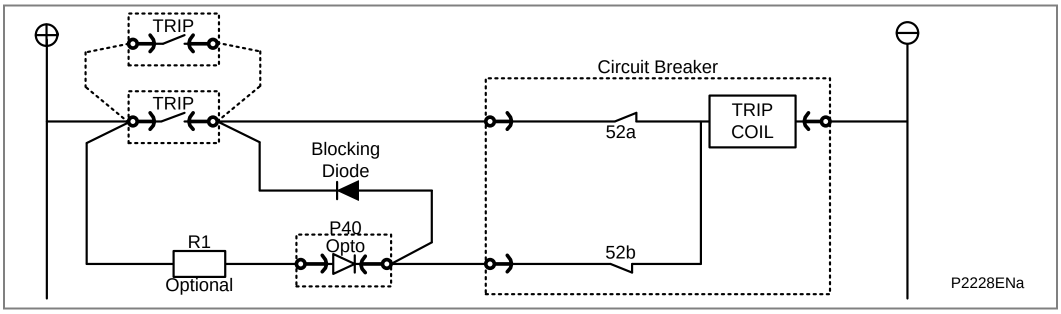


Figure 68 - TCS scheme 1

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 400 ms. 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 400 ms delay.

Resistor R1 is an optional resistor that can be fitted to prevent mal-operation of the circuit breaker if the opto input is inadvertently shorted, by limiting the current to <60 mA. 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 10 mA. 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	1.2 k	24/27
110/250	2.5 k	48/54
220/250	5.0 k	110/125

Table 17 - Resistor values for TCS scheme 1

Note	*When R1 is not fitted the opto voltage setting must be set equal to supply voltage of the supervision circuit.*

3.5.2 Scheme 1 PSL

Figure 69 shows the scheme logic diagram for the TCS scheme 1. Any of the available opto inputs can be used to indicate 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 400 ms to drop off/reset in the event of a trip circuit failure. The 400 ms 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 50 ms delay on pick-up timer prevents false LED and user alarm indications during the relay power up time, following an auxiliary supply interruption.

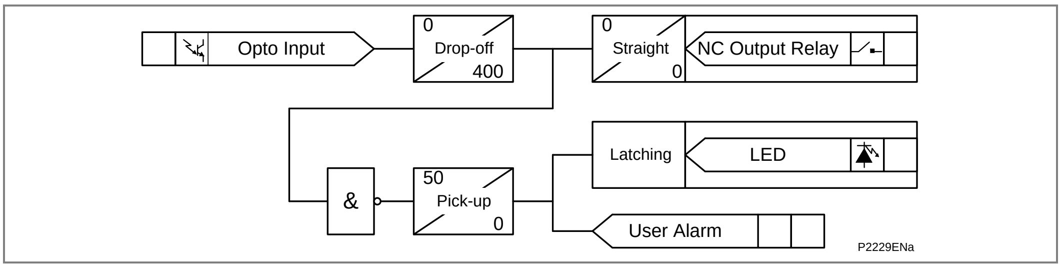


Figure 69 - PSL for TCS schemes 1 and 3

3.5.3 TCS Scheme 2

3.5.3.1 Scheme Description

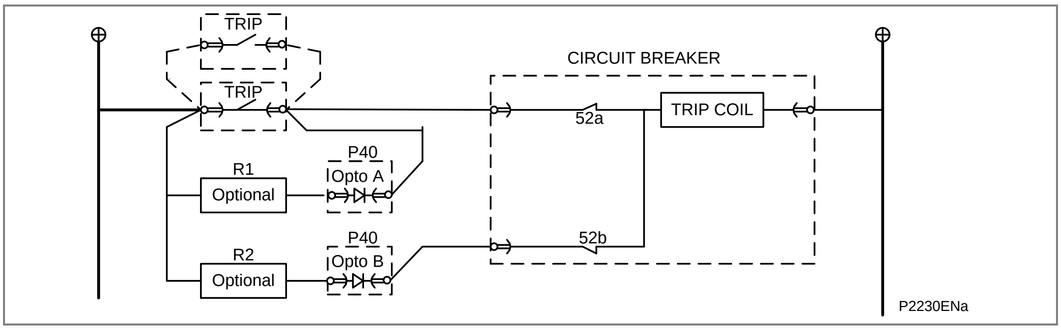


Figure 70 - TCS scheme 2

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) and opto's A and B are connected to CB Aux 3ph (52a) (DDB 611) and CB Aux 3ph (52b) (DDB 612) 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.

3.5.4 Scheme 2 PSL

The PSL for this scheme (Figure 71) 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.

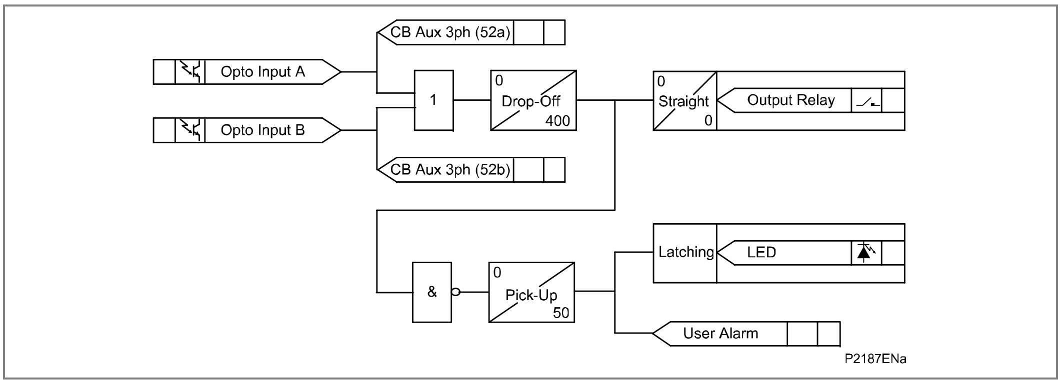


Figure 71 - PSL for TCS scheme 2

3.5.5 TCS scheme 3

3.5.5.1 Scheme description

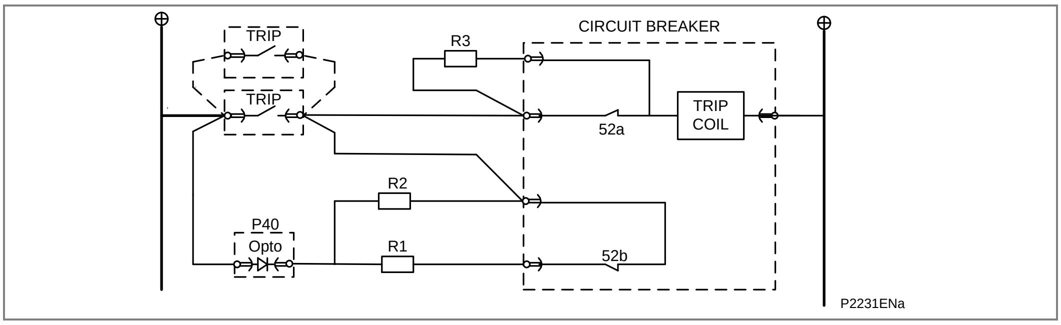


Figure 72 - TCS scheme 2

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, therefore 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 on 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	1.2 k	0.6 k	24/27
110/250	2.5 k	1.2 k	48/54
220/250	5.0 k	2.5 k	110/125

Table 18 - Resistor values for TCS scheme 2

Note	Scheme 3 is not compatible with auxiliary supply voltages of 30/34 volts and below.

3.5.6 Scheme 3 PSL

The PSL for Scheme 3 is identical to that of Scheme 1 (see Figure 68).

3.6 VT Connections

3.6.1 Open Delta (Vee Connected) VT's

The P342/P343/P344/P345 relay can be used with vee connected VTs by connecting the VT secondaries to C19, C20 and C21 input terminals, with the C22 input left unconnected (see Figures 2 and 18 in document *P34x/EN IN*).

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 on zero sequence voltage measurements should be disabled unless a direct measurement can be made via the measured VN1 input (C23 - C24). Therefore, neutral displacement protection, sensitive directional earth fault protection and CT supervision should be disabled unless the residual voltage is measured directly from the secondary of the earthing transformer or from a broken delta VT winding on a 5 limb VT.

The under and overvoltage protection can be set as phase to phase measurement with vee connected VTs. The underimpedance and the voltage dependent overcurrent use phase-phase voltages anyway, therefore the accuracy should not be affected. The protection functions which use phase-neutral voltages are the power, the loss of excitation and pole slipping protection; all are for detecting abnormal generator operation under 3-phase balanced conditions, therefore the 'neutral' point, although 'floating' will be approximately at the center of the three-phase voltage vectors.

The accuracy of 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 and impedance measurements that are also dependent on their respective single-phase voltages.

The phase to neutral voltage measurement accuracy can be improved by connecting 3, well matched, load resistors between the phase voltage inputs (C19, C20, C21) and neutral C22, therefore 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 $\pm$1% (6 W) resistors are used for the 110 V (Vn) rated relay, assuming the VT can supply this burden.

3.6.2 VT Single Point Earthing

The P34x & P391 range will function correctly with conventional three-phase VT’s earthed at any one point on the VT secondary circuit. Typical earthing examples being neutral earthing and yellow phase earthing.

4 CURRENT TRANSFORMER REQUIREMENTS

The current transformer requirements for each current input will depend on the protection function with which they are related and whether the line current transformers are being shared with other current inputs. Where current transformers are being shared by multiple current inputs, the kneepoint voltage requirements should be calculated for each input and the highest calculated value used.

The P342/P343/P344/P345 is able to maintain all protection functions in service over a wide range of operating frequency due to its frequency tracking system (5 - 70 Hz).

When the P342/P343/P344/P345 protection functions are required to operate accurately at low frequency, it will be necessary to use CT's with larger cores. In effect, the CT requirements need to be multiplied by fn/f, where f is the minimum required operating frequency and fn is the nominal operating frequency.

4.1 Generator Differential Function

4.1.1 Biased Differential Protection

The kneepoint voltage requirements for the current transformers used for the current inputs of the generator differential function, with settings of Is1 = 0.05 In, k1 = 0%, Is2 = 1.2 In, k2 = 150%, and with a boundary condition of through fault current ≤ 10 In, is:

For phase-earth faults

$V_k \geq 50I_n\ (R_{ct} + 2R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <120 If <10 In

$V_k \geq 30I_n\ (R_{ct} + 2R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R < 40 If < 10 In

Where the generator is impedance earthed and the maximum secondary earth fault current is less than I_n then the CT knee point voltage requirements are:

For phase-phase, 3 phase faults

$V_k \geq 25I_n\ (R_{ct} + R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <60 If <10 In

$V_k \geq 30I_n\ (R_{ct} + R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <100 If <10In, X/R <120 If <5In

$V_k \geq 40I_n\ (R_{ct} + R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <120 If <10 In

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability
I_n = Relay rated current
R_{ct} = Resistance of current transformer secondary winding (Ω)
R_L = Resistance of a single lead from relay to current transformer (Ω)
R_r = Resistance of any other protective relays sharing the current transformer (Ω)
If = maximum through fault current

For Class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than 2.5 I_n (<5% of the maximum perspective fault current 50 In, on which these CT requirements are based). For IEC standard protection class current transformers, it should be ensured that class 5P are used.

It is always recommended to use the same product type from one manufacturer and highly recommended to use Matched CT. And the load of CT secondary loop circuit should be kept equal approximately.

4.1.2 High Impedance Differential Protection

If the generator differential protection function is to be used to implement high impedance differential protection, then the current transformer requirements for phase faults are:

R_s = $[1.5 * (If) * (R_{CT} + 2R_L)] / IS1$

V_s = $1.5\ If\ (R_{CT} + 2R_L)$

$VK \geq 2 * Is1 * Rs = 2\ Vs$

Where:

R_s = Value of stabilizing resistor (ohms)
If = Maximum secondary through fault current level (amps)
VK = CT knee point voltage (volts)
I_{S1} = Current setting of differential element (amps)
R_{CT} = Resistance of current transformer secondary winding (ohms)
R_L = Resistance of a single lead from relay to current transformer (ohms)
V_s = Stability voltage

4.2 Generator-Transformer Differential Function

4.2.1 Biased Differential Protection

The kneepoint voltage requirements for the current transformers used for the current inputs of the generator-transformer differential function, with settings of Is1 = 0.2 In, k1 = 30%, Is2 = 1.0 In, k2 = 80%, and with a boundary condition of through fault current ≤ 16 In, is:

For phase-earth faults

$V_k \geq 80I_n (R_{ct} + 2R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <120 If <16 In,

X/R <600 If <10 In

$V_k \geq 30I_n (R_{ct} + 2R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R < 120 If < 10 In

$V_k \geq 110I_n (R_{ct} + 2R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <600 If <16 In

Where the generator is impedance earthed and the maximum secondary earth fault current is less than I_n then the CT knee point voltage requirements are:

For phase-phase, 3 phase faults

$V_k \geq 25I_n (R_{ct} + R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <60 If <10 In

$V_k \geq 30I_n (R_{ct} + R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <100 If <10 In,

X/R <120 If < 5 In

$V_k \geq 40I_n (R_{ct} + R_L + R_r)$ with a minimum of $\frac{60}{In}$ for X/R <120 If <10 In

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability

I_n = Relay rated current

R_{ct} = Resistance of current transformer secondary winding (Ω)

R_L = Resistance of a single lead from relay to current transformer (Ω)

R_r = Resistance of any other protective relays sharing the current transformer (Ω)

If = maximum through fault current

For Class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than 2.5 I_n (<5% of the maximum perspective fault current 50 In, on which these CT requirements are based). For IEC standard protection class current transformers, make sure that class 5P are used.

4.3 Voltage Dependent Overcurrent, Field Failure, Thermal Overload, Pole Slipping, Underimpedance and Negative Phase Sequence Protection Functions

When determining the current transformer requirements for an input that supplies several protection functions, it must be ensured that the most onerous condition is met. This has been taken into account in the formula given below. The formula is equally applicable for current transformers mounted at either the neutral-tail end or terminal end of the generator.

$V_k \geq 20\, I_n (R_{ct} + 2R_L + R_r)$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability

I_n = Relay rated current

R_{ct} = Resistance of current transformer secondary winding (Ω)

R_L = Resistance of a single lead from relay to current transformer (Ω)

R_r = Resistance of any other protective relays sharing the current transformer (Ω)

For class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than 1.0 I_n. For IEC standard protection class current transformers, make sure that class 5P are used.

4.4 Sensitive Directional Earth Fault Protection Function Residual Current Input

4.4.1 Line Current Transformers

With reference to section 2.17, the sensitive directional earth fault input current transformer could be driven by three residually connected line current transformers.

It has been assumed that the sensitive directional earth fault protection function will only be applied when the stator earth fault current is limited to the stator winding rated current or less. Also assumed is that the maximum X/R ratio for the impedance to a bus earth fault will be no greater than 10. The required minimum kneepoint voltage will therefore be:

$V_k \geq 6 I_n (R_{ct} + 2R_L + R_r)$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability

I_n = Relay rated current

R_{ct} = Resistance of current transformer secondary winding (Ω)

R_L = Resistance of a single lead from relay to current transformer (Ω).

R_r = Resistance of any other protective relays sharing the current transformer (Ω).

For class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than 0.3 I_n (<5% of the maximum perspective fault current 20 I_n, on which these CT requirements are based). For IEC standard protection class current transformers, make sure that class 5P are used.

4.4.2 Core Balanced Current Transformers

Unlike a line current transformer, the rated primary current for a core balanced current transformer may not be equal to the stator winding rated current. This has been taken into account in the formula:

$V_k > 6NI_n (R_{ct} + 2R_L + R_r)$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability

$$N = \frac{\text{Stator earth fault current}}{\text{Core balanced current transformer rated primary current}}$$

I_n = Relay rated current

R_{ct} = Resistance of current transformer secondary winding (Ω)

R_L = Resistance of a single lead from relay to current transformer (Ω)

R_r = Resistance of any other protective relays sharing the current transformer (Ω)

Note	*N should not be greater than 2. The core balance current transformer ratio should be selected accordingly.*

4.5 Stator Earth Fault Protection Function

The earth fault I_n current input is used by the stator earth fault protection function.

4.5.1 Non-Directional Definite Time/IDMT Earth Fault Protection

CT requirements for time-delayed earth fault overcurrent elements

VK ≥ $Icn/2 * (R_{CT} + 2R_L + R_{rn})$

4.5.2 Non-Directional Instantaneous Earth Fault Protection

CT requirements for instantaneous earth fault overcurrent elements

V_K ≥ $Isn (R_{CT} + 2R_L + R_{rn})$

Where:

V_K = Required CT knee-point voltage (volts)

Icn = Maximum prospective secondary earth fault current or 31 times I> setting (whichever is lower) (amps)

Isn = Earth fault setting (amps)

R_{CT} = Resistance of current transformer secondary winding (ohms)

R_L = Resistance of a single lead from relay to current transformer (ohms)

R_{rn} = Impedance of the relay neutral current input at In (ohms)

4.6 Restricted Earth Fault Protection

4.6.1 Low Impedance

$V_K \geq$ 24 * In * (R_{CT} + 2R_L) for X/R < 40 and If < 15 In

$V_K \geq$ 48 * In * (R_{CT} + 2R_L) for X/R < 40, 15 In < If < 40 In and 40 <X/R < 120, If < 15 In

Where:

$$V_k = \frac{VA \times ALF}{In} + ALF \times I_n \times R_{ct}$$

V_K = Required CT knee point voltage (volts)

I_n = rated secondary current (amps)

R_{CT} = Resistance of current transformer secondary winding (Ω)

R_L = Resistance of a single lead from relay to current transformer (Ω)

If = Maximum through fault current level (amps)

4.6.2 High Impedance

The High Impedance Restricted Earth Fault element shall maintain stability for through faults and operate in less than 40 ms for internal faults provided the following equations are met in determining CT requirements and the value of the associated stabilizing resistor:

Rs = (If) * (R_{CT} + 2R_L) /IS1

V_s = 1.5 If (R_{CT} + 2R_L)

$V_K \geq$ 4 * Is1 * Rs = 4 Vs

Where:

Rs = Value of Stabilizing resistor (ohms)

If = Maximum secondary through fault current level (amps)

V_K = CT knee point voltage (volts)

I_{S1} = Current setting of REF element (amps)

R_{CT} = Resistance of current transformer secondary winding (ohms)

R_L = Resistance of a single lead from relay to current transformer (ohms)

V_s = Stability voltage

4.7 Reverse and Low Forward Power Protection Functions

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.

4.7.1 Protection Class Current Transformers

For less sensitive power function settings (>3%Pn), the phase current input of the P34x & P391 should be driven by a correctly loaded class 5P protection current transformer.

To correctly load the current transformer, its VA rating should match the VA burden (at rated current) of the external secondary circuit through which it is required to drive current.

4.7.2 Metering Class Current Transformers

For low Power settings (<3%Pn), the I_n Sensitive current input of the P34x & P391 should be driven by a correctly loaded metering class current transformer. The current transformer accuracy class will be dependent on the reverse power and low forward power sensitivity required. The table below indicates the metering class current transformer required for various power settings below 3%Pn.

To correctly load the current transformer, its VA rating should match the VA burden (at rated current) of the external secondary circuit through which it is required to drive current. Use of the P34x & P391 sensitive power phase shift compensation feature will help in this situation.

Reverse and low forward power settings %Pn	Metering CT class
0.5	0.1
0.6	
0.8	0.2
1.0	
1.2	
1.4	
1.6	0.5
1.8	
2.0	
2.2	
2.4	
2.6	
2.8	
3.0	1.0

Table 19 - Sensitive power current transformer requirements

4.8 100% Stator Earth Fault Protection Function 20 Hz Inputs

4.8.1 Line Current Transformers

4.8.1.1 Generator Earthed via a Primary Resistor in Generator Starpoint

It has been assumed that the 100% stator earth fault protection function will only be applied when the stator earth fault current is limited to <2x rated current or less as the linear range of the sensitive current input is 2 In. The required minimum kneepoint voltage is:

$V_k \geq fn/20 \times 2\ I_n (R_{ct} + 2R_L + Rr)$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability

I_n = Relay rated current

R_{ct} = Resistance of current transformer secondary winding (Ω)

R_L = Resistance of a single lead from relay to current transformer (Ω).

Rr = Resistance of any other protective relays sharing the current transformer (Ω).

f_n = fundamental frequency 50 or 60 Hz (fn/20 is to account for operation at 20 Hz)

For class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than 0.1 I_n (<5% of the maximum perspective fault current 2 I_n, on which these CT requirements are based). For IEC standard protection class current transformers, it should be ensured that class 5P is used; a 15 VA 5P10 CT will be adequate for most applications.

4.8.1.2 Generator Earthed via Earthing Transformer and Secondary Resistor at the Terminals or Star Point of the Generator

A 400/5A CT can be ordered for this application, Vk = 720 V (50/60 Hz)

4.8.2 Earthing Transformers

To prevent the secondary load resistance from becoming too small (it should be > 0.5 Ω where possible) a high secondary voltage, such as 500 V, should be chosen for the neutral or earthing transformer.

It is important that the earthing transformer never becomes saturated otherwise ferroresonance may occur. It is sufficient that the transformer knee point voltage be equal to the generator rated line voltage, Vn.

4.8.2.1 Generator Earthed via a Primary Resistor in Generator Starpoint

Voltage transformer rating: Vn/√3 / 500 V, 3000 VA (for 20 s) class 0.5 (non-saturated up to Vn, Generator)

Vn = rated generator line voltage (phase-phase)

4.8.2.2 Generator Earthed via Earthing Transformer and Secondary Resistor at the Terminals of the Generator

Voltage transformer rating: Vn/√3 / 500/3 V (non-saturated up to Vn, Generator)

The transformer VA rating for 20 s per phase = $1.3 \times 1/3 \times If \times Vn \times \sqrt{3} \times \sqrt{10}/\sqrt{20}$

for 3 single phase transformers.

If = primary fault current

The 1.3 accounts for an overvoltage factor from field forcing.

The $\sqrt{10}/\sqrt{20}$ increases the rating from 10 to 20 s.

For a 3 phase transformer the VA rating is 3 times higher.

4.8.2.3 Generator Earthed via Earthing Transformer and Secondary Resistor at the Starpoint of the Generator

Voltage transformer rating: Vn/√3 / 500 V (non-saturated up to Vn, Generator)

The transformer VA rating for 20 s per phase = 1.3 x If x Vn x √3 x √10/√20

The 1.3 accounts for an overvoltage factor from field forcing.

The √10/√20 increases the rating from 10 to 20 s.

4.9 Converting an IEC185 Current Transformer Standard Protection Classification to a Kneepoint Voltage

The suitability of an IEC standard protection class current transformer can be checked against the kneepoint voltage requirements specified previously.

If, for example, the available current transformers have a 15 VA 5P 10 designation, then an estimated kneepoint voltage can be obtained as follows:

$$V_k = \frac{VA \times ALF}{I_n} + ALF \times I_n \times R_{ct}$$

Where:

V_k	=	Required kneepoint voltage
VA	=	Current transformer rated burden (VA)
ALF	=	Accuracy limit factor
I_n	=	Current transformer secondary rated current (A)
R_{ct}	=	Resistance of current transformer secondary winding (Ω)

If R_{ct} is not available, then the second term in the above equation can be ignored.

Example: 400/5 A, 15 VA 5P 10, R_{ct} = 0.2 Ω

$$V_k = \frac{15 \times 10}{5} + 10 \times 5 \times 0.2$$

$$= 40 \text{ V}$$

4.10 Converting IEC185 Current Transformer Standard Protection classification to an ANSI/IEEE Standard Voltage Rating

The Px40 series protection is compatible with ANSI/IEEE current transformers as specified in the IEEE C57.13 standard. The applicable class for protection is class "C", which specifies a non air-gapped core. The CT design is identical to IEC class P, or British Standard class X, but the rating is specified differently.

The ANSI/IEEE "C" Class standard voltage rating required will be lower than an IEC knee point voltage. This is because the ANSI/IEEE voltage rating is defined in terms of useful output voltage at the terminals of the CT, whereas the IEC knee point voltage includes the voltage drop across the internal resistance of the CT secondary winding added to the useful output. The IEC/BS knee point is also typically 5% higher than the ANSI/IEEE knee point.

Therefore:

Vc = [Vk - Internal voltage drop] / 1.05

= [Vk - (In . RCT . ALF)] / 1.05

Where:

Vc	=	"C" Class standard voltage rating
Vk	=	IEC Knee point voltage required
In	=	CT rated current = 5 A in USA
R_{CT}	=	CT secondary winding resistance (for 5A CTs, the typical resistance is 0.002 ohms/secondary turn)
ALF class	=	The CT accuracy limit factor, the rated dynamic current output of a "C" CT (Kssc) is always 20 x In

The IEC accuracy limit factor is identical to the 20 times secondary current ANSI/IEEE rating.

Therefore:

Vc = [Vk - (100 . R_{CT})] / 1.05

5 AUXILIARY SUPPLY FUSE RATING

In the Safety Information section 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 250 V minimum and compliant with IEC 60269-2 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.

Table 20 recommends advisory limits on relays connected per fused spur. This applies to The 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 Px40 relays recommended per fuse				
Battery nominal voltage	6A	10A fuse	15 or 16A fuse	Fuse rating > 16A
24 to 54 V	2	4	6	Not permitted
60 to 125 V	4	8	12	Not permitted
138 to 250 V	6	10	16	Not permitted

Table 20 - Maximum number of Px40 relays recommended per fuse

Alternatively, Miniature Circuit Breakers (MCB) may be used to protect the auxiliary supply circuits.

Notes:

USING THE PSL EDITOR

CHAPTER 7

Date:	05/2017	
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:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 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) P44x: 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2)	P54x (P543, P544, P545 & P546): 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) P547: 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P74x: 10P740xx (xx = 01 to 07) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)

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FIGURES

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Notes:

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.

Note	*MiCOM S1 Studio has been renamed as Easergy Studio.*

2 EASERGY STUDIO (MICOM S1 STUDIO) PSL EDITOR

Note	*MiCOM S1 Studio has been renamed as Easergy Studio.*

The PSL Editor can be used inside Easergy Studio (MiCOM S1 Studio) or directly.
This chapter assumes that you are using the PSL Editor from within Easergy Studio (MiCOM S1 Studio).
If you use it from Easergy Studio (MiCOM S1 Studio), the Studio software will be locked whilst you are using the PSL editor software. The Studio software will be unlocked when you close the PSL Editor software.
The Easergy Studio (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 Easergy Studio (MiCOM S1 Studio).**

2.1 How to Obtain Easergy Studio (MiCOM S1 Studio) Software

Easergy Studio (MiCOM S1 Studio) is available from the Schneider Electric website:

- www.schneider-electric.com

2.2 To Start Easergy Studio (MiCOM S1 Studio)

To Start the Easergy Studio (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 Easergy Studio (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 the *Example of a PSL editor module* diagram.

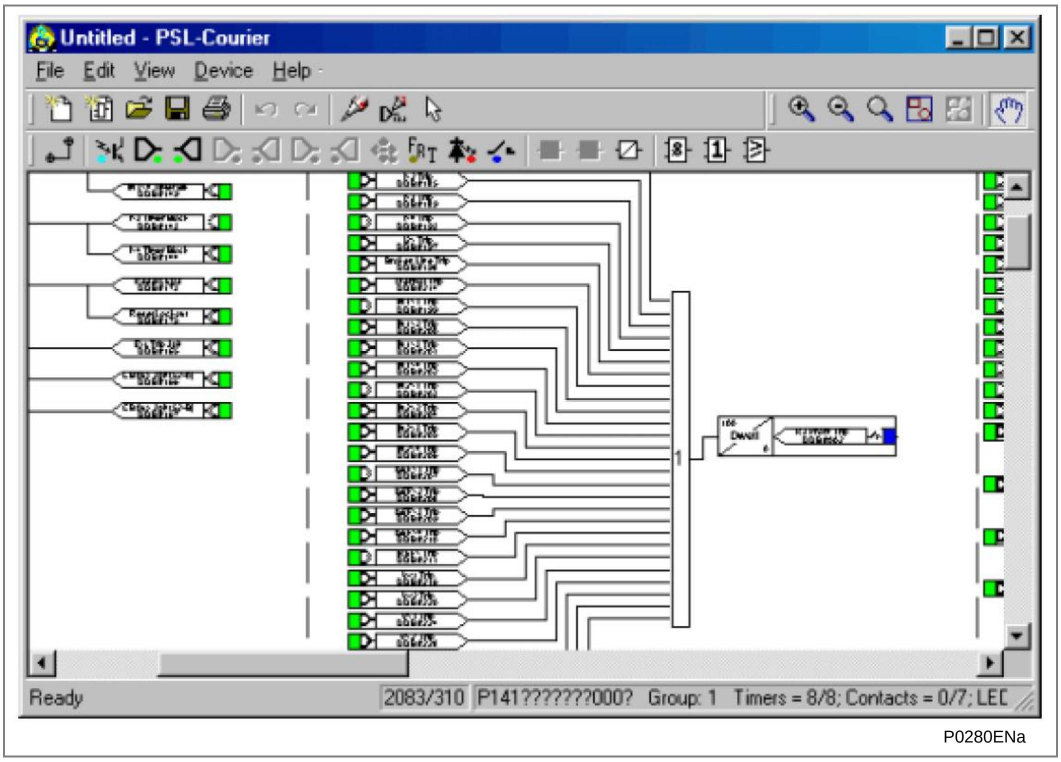


Figure 1 - Example of a PSL editor module

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 the Easergy Studio (MiCOM S1 Studio) User 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:

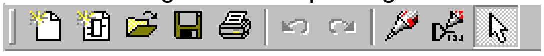
- One or more gates, LED signals, contact signals, and/or timers have their outputs linked directly back to their inputs. An erroneous link of this sort could lock up the relay, or cause other more subtle problems to arise.
- Inputs to Trigger (ITT) exceeds the number of inputs. If a programmable gate 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.

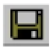
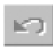
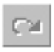
3 TOOLBAR AND COMMANDS

There are a number of toolbars available for easy navigation and editing of PSL.

3.1 Standard Tools

For file management and printing.

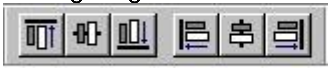


	Blank Scheme	Create a blank scheme based on a relay model.
	Default Configuration	Create a default scheme based on a relay model.
	Open	Open an existing diagram.
	Save	Save the active diagram.
	Print	Display the Windows Print dialog, enabling you to print the current diagram.
	Undo	Undo the last action.
	Redo	Redo the previously undone action.
	Redraw	Redraw the diagram.
	No 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

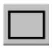
To align logic elements horizontally or vertically into groups.



	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 until either 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.

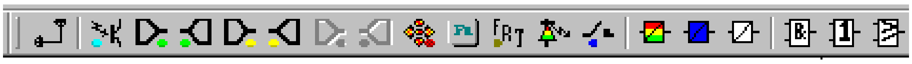
3.7 Zoom and Pan Tools

For scaling the displayed screen size, viewing the entire PSL, or zooming to a selection.

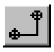
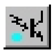
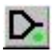
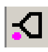
	Zoom In	Increases the Zoom magnification by 25%.
	Zoom Out	Decreases the Zoom magnification by 25%.
	Zoom	Enable the zoom function. While this button is active, the mouse pointer is displayed as a magnifying glass. Right-clicking will zoom out and left-clicking will zoom in. Press the ESC key to return 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.

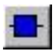
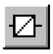
3.8 Logic Symbols

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.



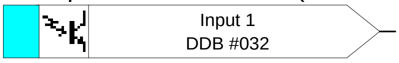
P2718ENa

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 OutCreate 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.** **Available functions will depend on model/firmware version.**

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:

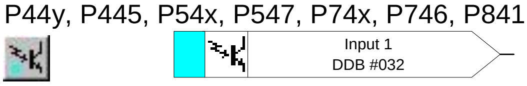
- An attempt to connect to a signal that is already driven. The reason for the refusal may not be obvious because the signal symbol may appear elsewhere in the diagram.

  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

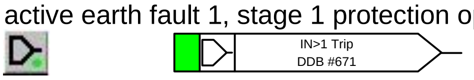
Each opto input can be selected and used for programming in PSL. Activation of the opto input drives an associated DDB signal.
For example, activating opto Input L1 asserts DDB 032 in the PSL for the P14x, P34x, P44y, P445, P54x, P547, P74x, P746, P841, P849 products.



DDB Nos	*“Input 1 DDB #064” applies to: P24x, P64x.* *“Opto Label DDB #064” applies to: P44x.*

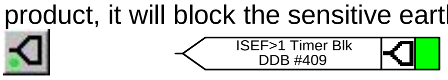
4.4 Input Signal Properties

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.



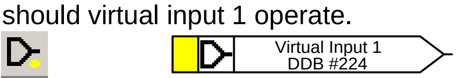
4.5 Output Signal Properties

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.



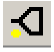
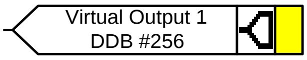
4.6 GOOSE Input Signal Properties

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 Easergy Studio (MiCOM S1 Studio) User 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.

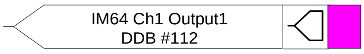



4.8 Control In Signal Properties

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, when operated control input 1 will assert DDB 192 in the PSL for the P44y, P54x, P547 and P841 products.

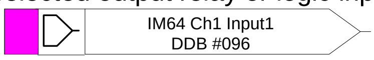

4.9 InterMiCOM Output Commands Properties

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 products.

4.10 InterMiCOM Input Commands Properties

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.

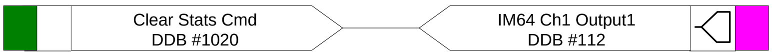


Example:

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.



P2688ENa

P2689ENa

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 products.

4.12 Fault Recorder Trigger Properties

The fault recording facility can be activated by driving the fault recorder trigger DDB signal.

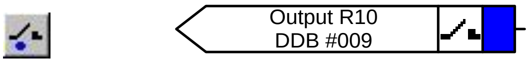
For example assert DDB 702 to activate the fault recording in the PSL for the P44y, P54x, P547 or P841 product.

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.

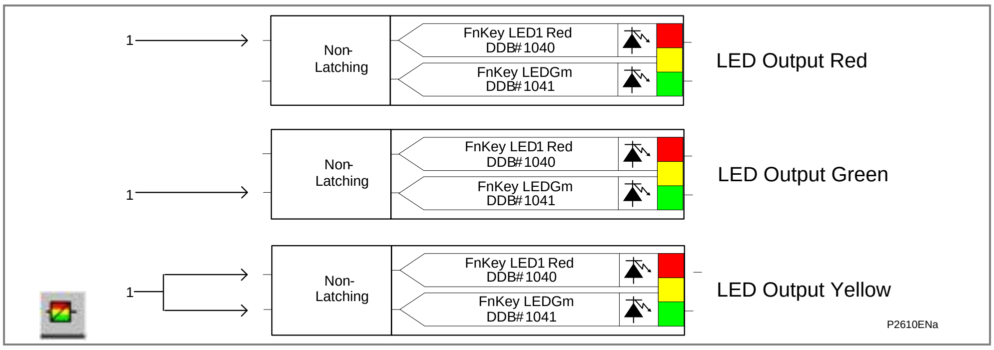


Figure 3 - Red, green and yellow LED outputs

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.

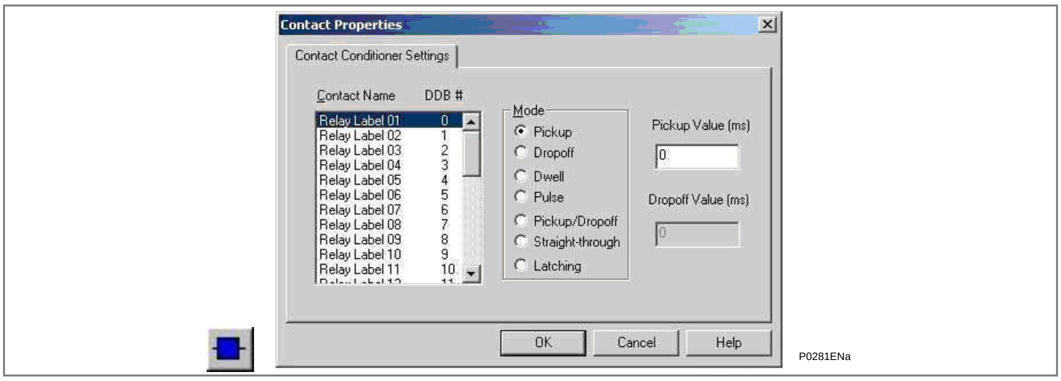


Figure 4 - Contact conditioner settings

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.

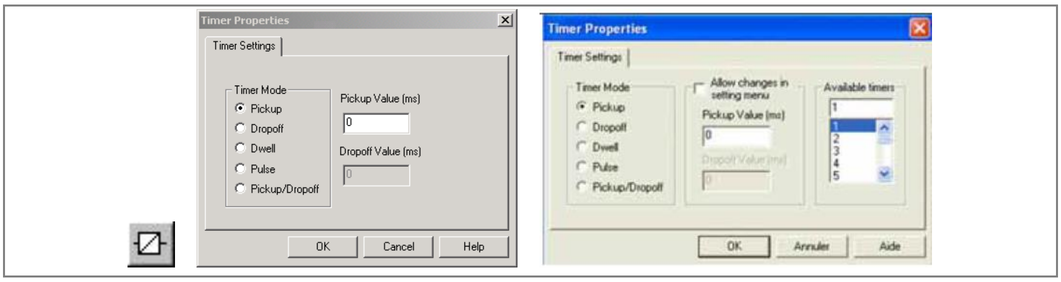


Figure 5 - Timer settings

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.

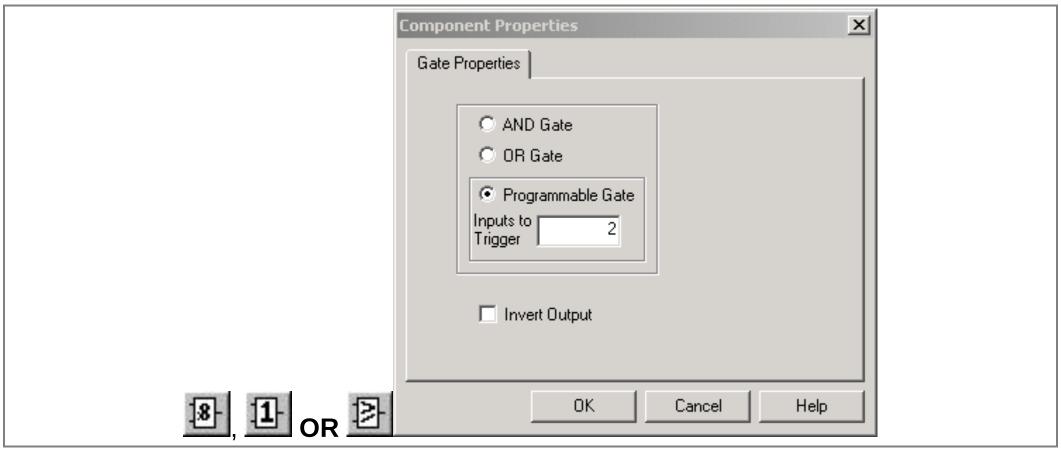


Figure 6 - Gate properties

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 – Reset input dominant
0	0	0	0	0
0	1	0	0	0
1	0	1	1	1
1	1	0	1	0

Table 1 - SR programmable gate properties

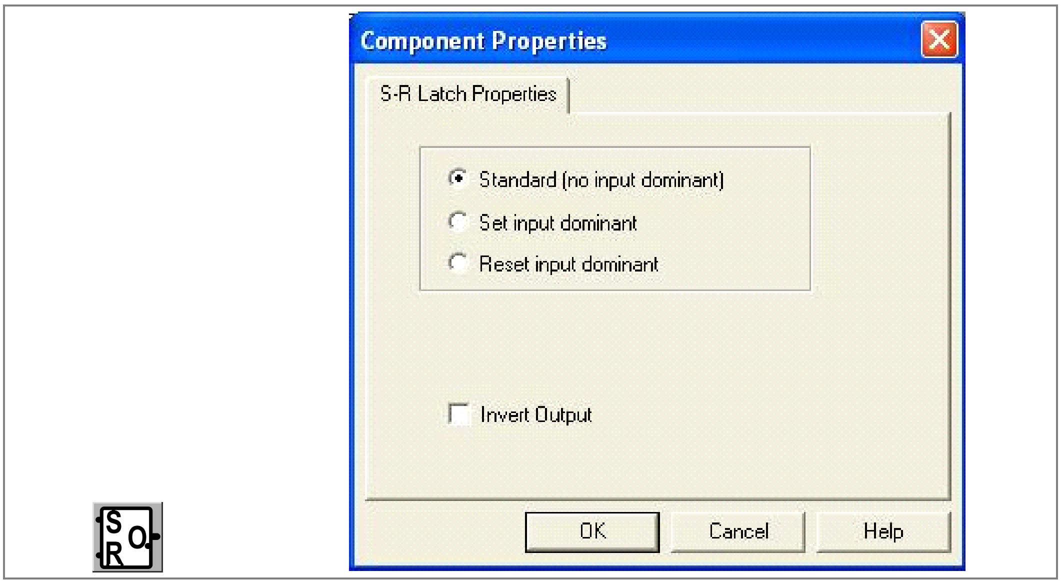


Figure 7 - SR latch component properties

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.

4.20 PSL Signal Grouping Modes

PSL Signal Grouping Nodes

For Software Version D1a and later, these DDB “Group” Nodes can be mapped to individual or multiple DDBs in the PSL:

PSL Group Sig 1
PSL Group Sig 2
PSL Group Sig 3
PSL Group Sig 4

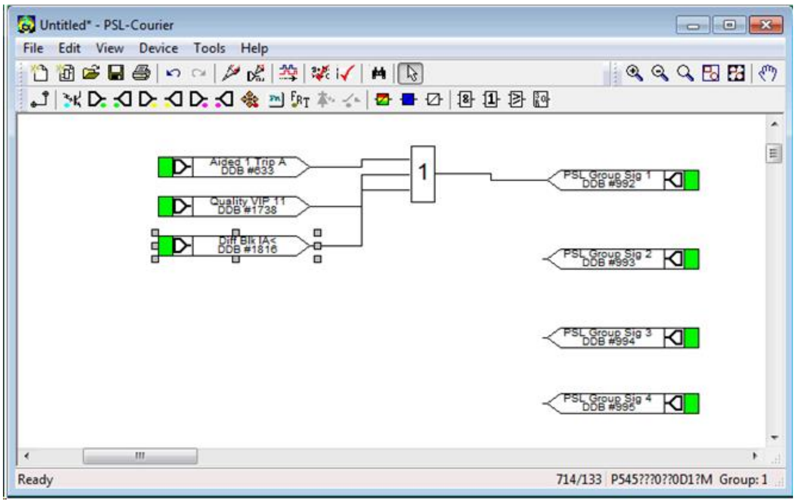
There are now four additional ***DDB Group Sig x*** Nodes that can be mapped to individual or multiple DDBs in the PSL. These can then be set to trigger the DR via the DISTURBANCE RECORD menu.

These "Nodes" are general and can also be used to group signals together in the PSL for any other reason. These four nodes are available in each of the four PSL setting groups.

Number	PSL Group Sig
992	PSL Group Sig 1
993	PSL Group Sig 2
994	PSL Group Sig 3
995	PSL Group Sig 4

1. For a control input, the DR can be triggered directly by triggering directly from the Individual Control Input (e.g. Low to High (L to H) change)
2. For an input that cannot be triggered directly, or where any one of a number of DDBs are required to trigger a DR, map the DDBs to the new PSL Group sig n and then trigger the DR on this.

e.g. in the PSL:

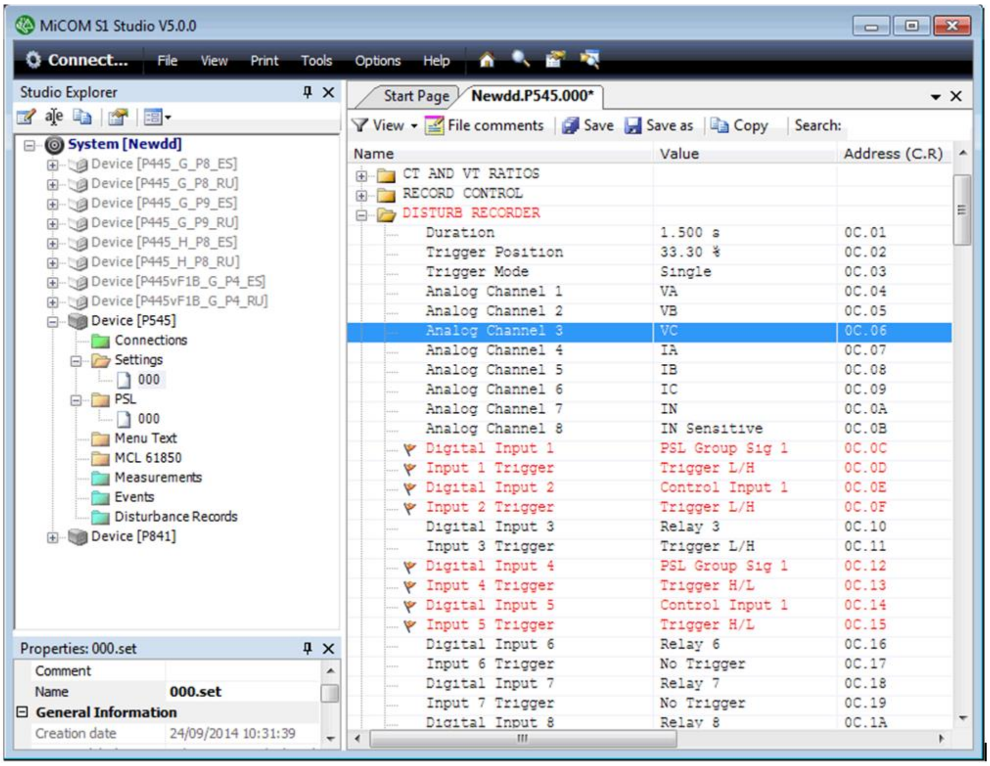


P0638ENa

Figure 8 - PSL diagram

In the DR Settings:

- Digital Input 1 is triggered by the PSL Group Sig 1 (L to H)
- Digital Input 2 is triggered by Control Input 1 (L to H)



P0639ENa

Figure 9 – Easergy Studio (MiCOM S1 Studio) Disturb Recorder table diagram

If triggering on both edges is required map another DR channel to the H/L as well

Digital Input 4 is triggered by the PSL Group Sig 1 (H to L)

Digital Input 5 is triggered by Control Input 1 (H to L)

5 SPECIFIC TASKS

Note	*MiCOM S1 Studio has been renamed as Easergy Studio.*

5.1 Digital Input Label Operation (P44y, P54x, P445 & P841 only)

The digital input labels can be modified via the MiCOM Px40 user interface or Easergy Studio (MiCOM S1 Studio). The following example is using S1 Studio Version 5.0.0. The digital input labels are available in the “DR CHAN LABELS” folder in the settings file as shown below:

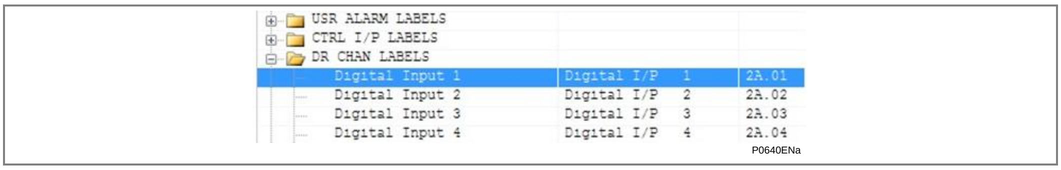


Figure 10 - DR Chan Labels tree

Easergy Studio (MiCOM S1 Studio) removes leading spaces from the value field so making the ‘D’ look as if it’s the 1st character in the label. The default values above in fact have a leading space which is used to switch off the use of the label as show below in the change settings view.

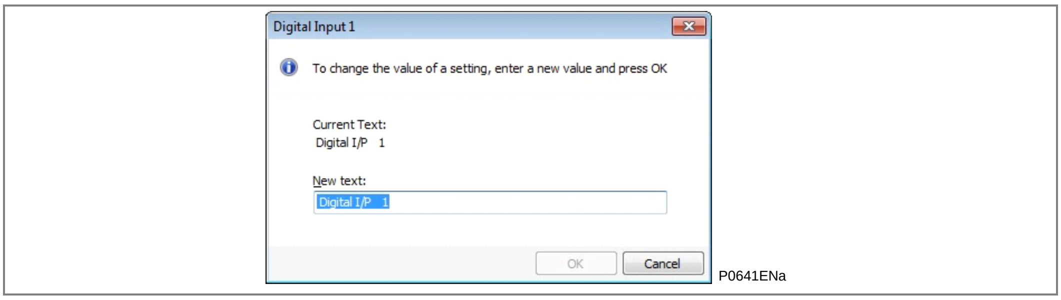


Figure 11 - Digital Input 1 dialog box

Pressing OK will save the setting and return to the settings page as follows:

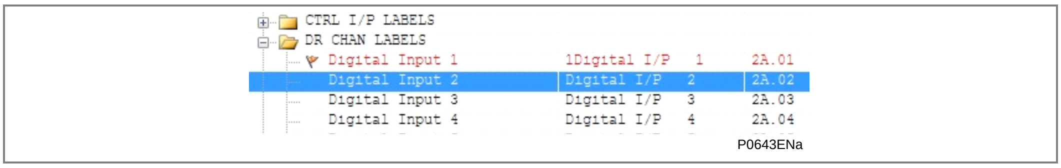


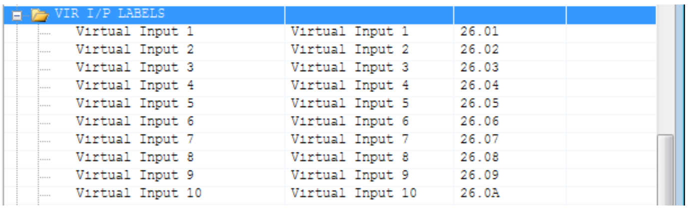
Figure 12 - DR Chan Labels tree

Digital Input 1 label will now be used in the Disturbance Record when the settings file is downloaded to the relay.

5.2 Virtual Input Label Operation

The Virtual Input labels can be modified via the MiCOM Px40 user interface or Easergy Studio (MiCOM S1 Studio). The following example is using S1 Studio Version 5.0.0.

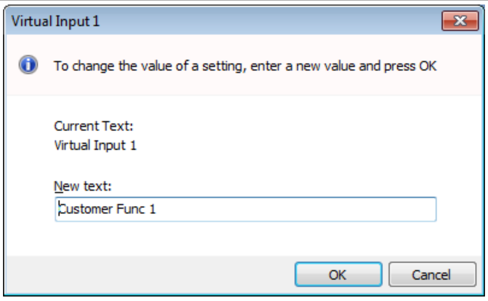
The default labels are available in the “VIR I/P LABELS” (or “VIRT I/P LABELS”) folder in the settings file as shown below:



P0649ENa

Figure 13 - MiCOM S1 Studio VIR I/P Labels Tree

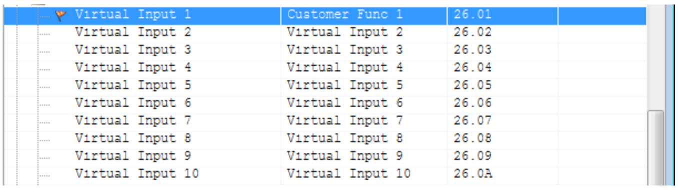
The default “Virtual Input” labels can be changed to suit the customer requirements. For example, to change default text from “Virtual Input 1” to “Customer Func 1” open the ***Virtual Input 1*** dialog box, and change “Virtual Input 1” in the ***New Text:*** text box to be “Customer Func 1”, as follows:



P0651ENa

Figure 14 - Virtual Input 1 dialog box

Pressing OK will save the setting and return to the settings page as follows:



P0668ENa

Figure 15 - Easergy Studio (MiCOM S1 Studio) VIR I/P Labels Tree

The above “Customer Func 1” label text will now be used in place of “Virtual Input 1” in the Disturbance / Event Records after the settings file is downloaded to the relay.

5.3 Virtual Output Label Operation

The Virtual Output labels can be modified via the MiCOM Px40 user interface or Easergy Studio (MiCOM S1 Studio). The following example is using S1 Studio Version 5.0.0.

The virtual Output labels are available in the “VIR O/P LABELS” ” (or “VIRT O/P LABELS”) folder in the settings file as shown below:

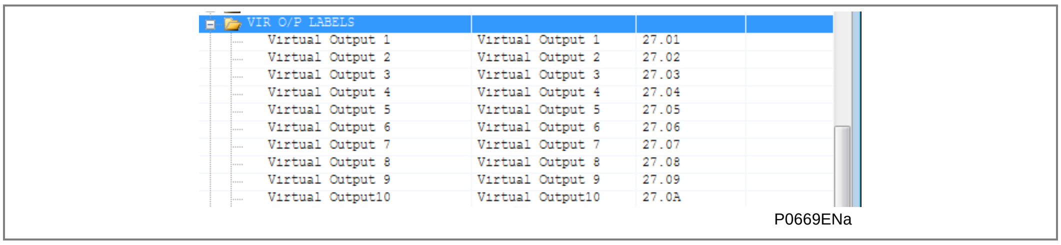


Figure 16 - Easergy Studio (MiCOM S1 Studio) VIR O/P Labels Tree

The default “Virtual Output Labels” can be changed to suit the customer requirements. The process is identical to the previously described procedure for the Virtual Input Labels.

5.4 SR/MR User Alarm Label Operation

The SR/MR User Alarm input labels can be modified via the MiCOM Px40 user interface or Easergy Studio (MiCOM S1 Studio). This example is using S1 Studio Version 5.0.0.

The default labels are available in the “USR ALARM LABELS” folder in the settings file as shown below:

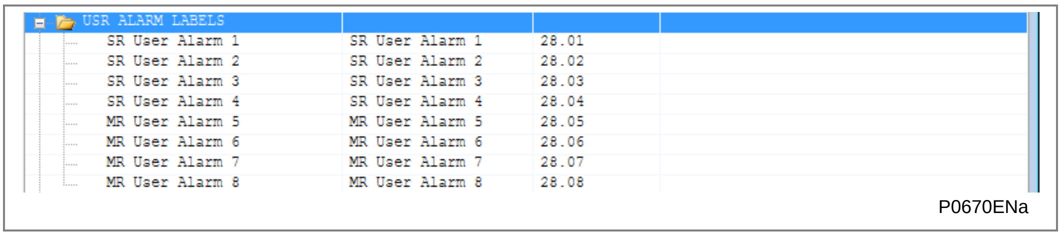


Figure 17 - Easergy Studio (MiCOM S1 Studio) USR Labels Tree

The default “SR User Alarm” and “MR User Alarm” labels can be changed to suit the customer requirements. For example, to change default text from “SR User Alarm 1” to “Customer Alarm 1” open the ***SR User Alarm 1*** dialog box and change “SR User Alarm 1” in the ***New Text:*** Text box to be “Customer Alarm 1”.

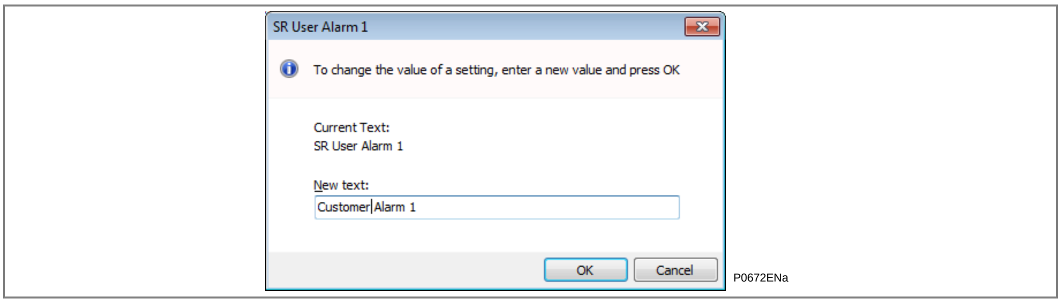


Figure 18 – User Alarm dialog box

Pressing OK will save the setting and return to the settings page as follows:

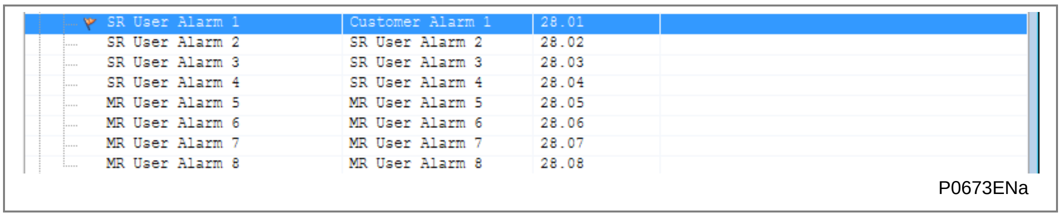


Figure 19 - Virtual Input 1 settings

The above “Customer Alarm 1” label text will now be used in place of “SR User Alarm 1” in the Disturbance / Event Records after the settings file is downloaded to the relay.

5.5 Settable Control Input Operation (P14x, P44y, P54x, P445 & P841 only)

The settings should be applied to all relays in the current differential protection scheme. As from Software Versions C1/D1/F1/G4/H4/J4, there are now 32 Standard Control Inputs and 16 additional Settable Control Inputs available. These are settable via the "CONTROL INPUTS" folder and are located after the standard "Control Input" labels in the relevant settings file.

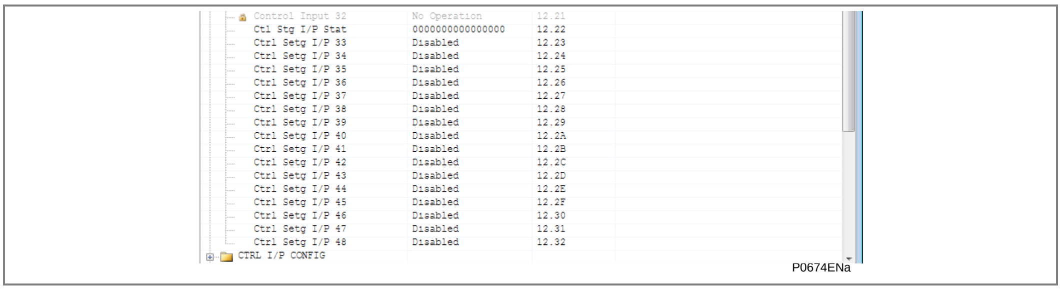


Figure 20 - Easergy Studio (MiCOM S1 Studio) Control Inputs tree

Each Settable control Input "Ctrl Setg I/P xx" can be controlled using Enable / Disable settings. To change from (the default) Disabled to Enabled, open the ***Ctrl Setg I/P xx*** dialog box, then change Disabled to Enabled in the ***New Setting*** drop-down list box:

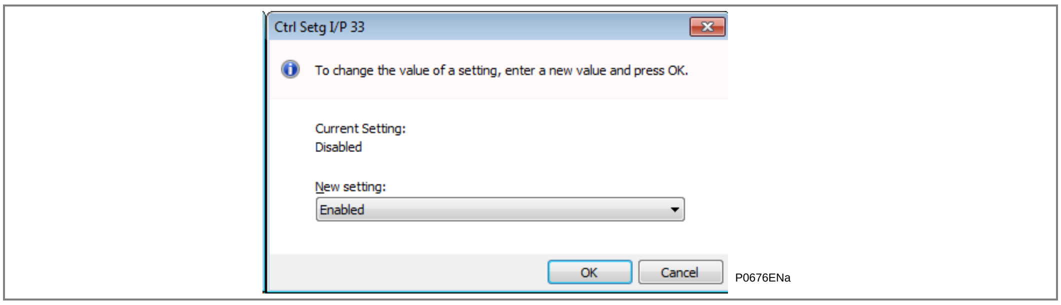


Figure 21 – Ctrl Setg I/P 33 dialog box

Pressing OK will save the setting and return to the settings page as follows:

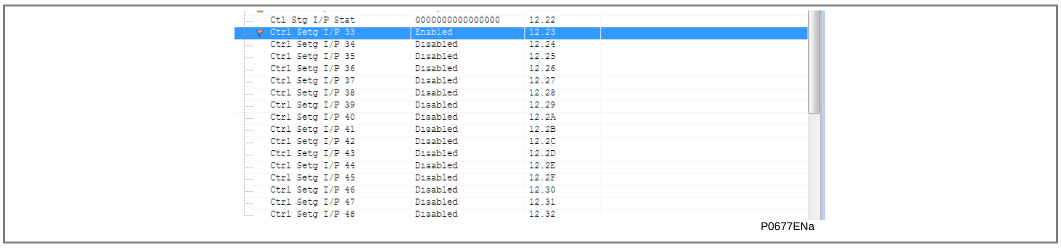


Figure 22 - Easergy Studio (MiCOM S1 Studio) Control Inputs (Ctl Setg I/P 33) tree

The setting "Ctl Stg I/P Stat" can be used to control multiple "Ctrl Setg I/P" at the same time, e.g. clear Ctrl Setg I/P 33 and set Ctrl Setg I/P 34 to 38, but please note that the status will not be reflected in the individual inputs settings or vice versa.

This cell may be hidden in the Easergy Studio (MiCOM S1 Studio) files.

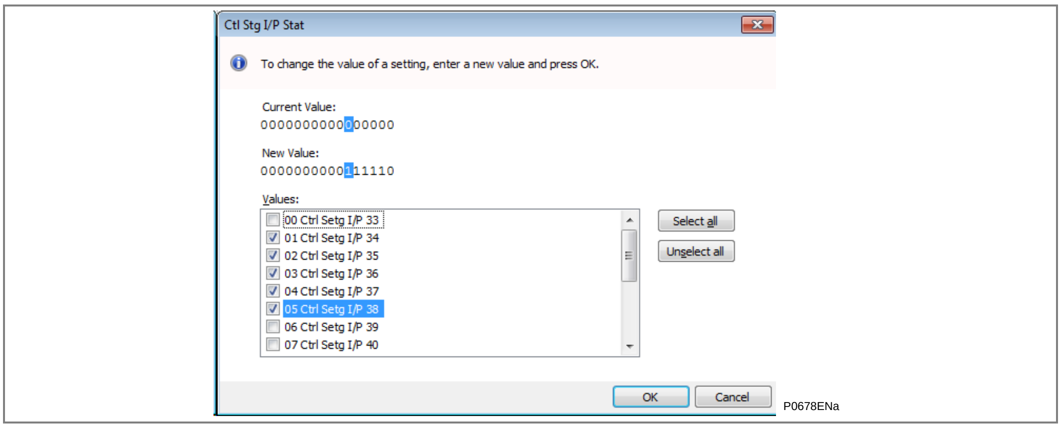


Figure 23 – Ctrl Stg I/P Stat dialog box

5.6 Settable Control Setg I/P Label Operation (P14x, P44y, P54x, P445 & P841 only)

The default labels are available in the “CTRL I/P LABELS” folder and are located after the standard “Control Input” labels in the settings file as shown below:

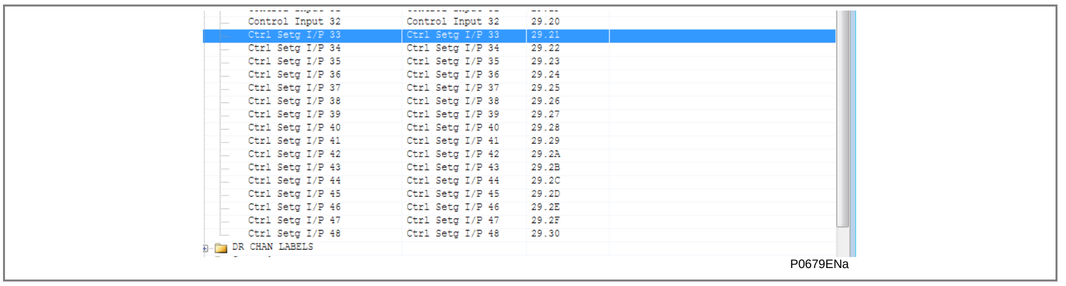


Figure 24 - Easergy Studio (MiCOM S1 Studio) Control I/P Labels (Ctl Setg I/P 33) tree

The default “Ctrl Setg I/P” labels can be changed to suit the customer requirements using the same procedure as for the standard “Control Inputs”. For example to change the default text from “Ctrl Setg I/P 33” to “Custom Ctrl Sg 1” open the ***Ctrl Setg I/P 33*** dialog box, then change “Ctrl Setg I/P 33” in the ***New Text:*** box to be “Custom Ctrl Sg 1”.

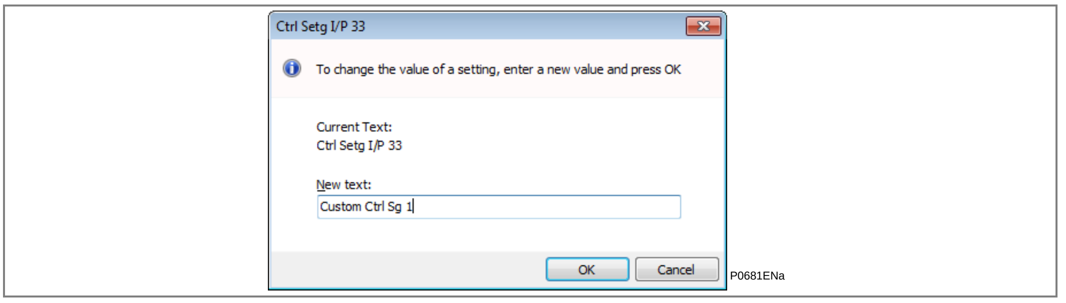


Figure 25 – Ctrl Setg I/P 33 dialog box

Pressing OK will save the setting and return to the settings page as follows:

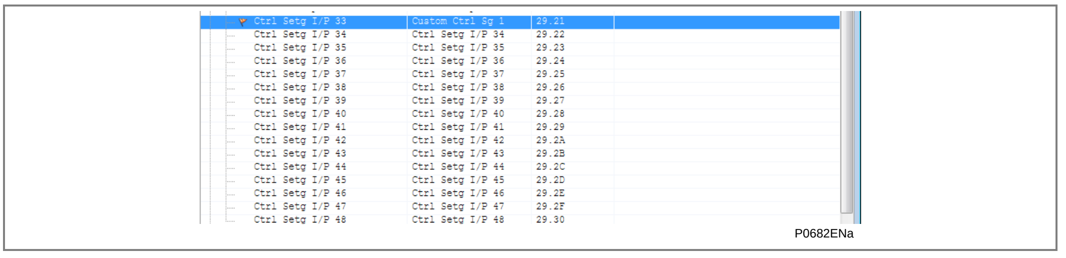


Figure 26 - Easergy Studio (MiCOM S1 Studio) Control I/P Labels (Ctl Setg I/P 33) tree

The above “Custom Ctrl Sg 1” label text will now be used in place of “Ctrl Setg I/P 33” in the Disturbance / Event Records after the settings file is downloaded to the relay.

6 MAKING A RECORD OF MICOM PX40 DEVICE SETTINGS

6.1 Using Easergy Studio (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 Easergy 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 the ***Extract Settings from a MiCOM Px40 Device*** section.
- **Send** lets you send the settings you currently have open in Easergy Studio. A summary is given in the ***Send Settings to a MiCOM Px40 Device*** section.

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 this is provided in the Easergy Studio help.
A quick summary of the main steps is given here. In each case, you need to make sure that:

- Your computer includes the Easergy 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).

6.2 Extract Settings from a MiCOM Px40 Device

Full details of how to do this is provided in the Easergy Studio help.
As a quick guide, you need to do the following:

1. In Easergy 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. 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.

6.3 Send Settings to a MiCOM Px40 Device

Full details of how to do this is provided in the Easergy Studio help.

As a quick guide, you need to do the following:

1. In Easergy 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. 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 Send To dialog box by clicking the Close button.

PROGRAMMABLE LOGIC

CHAPTER 8

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

CONTENTS

TABLES

FIGURES

Notes:

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	Element Name	Source	Type	Description	P342	P343	P344	P345
0	see 4B01	DDB_OUTPUT_RELAY_1	SW	RELAY	Output Relay 1	*	*	*	*
1	see 4B02	DDB_OUTPUT_RELAY_2	SW	RELAY	Output Relay 2	*	*	*	*
2	see 4B03	DDB_OUTPUT_RELAY_3	SW	RELAY	Output Relay 3	*	*	*	*
3	see 4B04	DDB_OUTPUT_RELAY_4	SW	RELAY	Output Relay 4	*	*	*	*
4	see 4B05	DDB_OUTPUT_RELAY_5	SW	RELAY	Output Relay 5	*	*	*	*
5	see 4B06	DDB_OUTPUT_RELAY_6	SW	RELAY	Output Relay 6	*	*	*	*
6	see 4B07	DDB_OUTPUT_RELAY_7	SW	RELAY	Output Relay 7	*	*	*	*
7	see 4B08	DDB_OUTPUT_RELAY_8	SW	RELAY	Output Relay 8	*	*	*	*
8	see 4B09	DDB_OUTPUT_RELAY_9	SW	RELAY	Output Relay 9	*	*	*	*
9	see 4B0A	DDB_OUTPUT_RELAY_10	SW	RELAY	Output Relay 10	*	*	*	*
10	see 4B0B	DDB_OUTPUT_RELAY_11	SW	RELAY	Output Relay 11	*	*	*	*
11	see 4B0C	DDB_OUTPUT_RELAY_12	SW	RELAY	Output Relay 12	*	*	*	*
12	see 4B0D	DDB_OUTPUT_RELAY_13	SW	RELAY	Output Relay 13	*	*	*	*
13	see 4B0E	DDB_OUTPUT_RELAY_14	SW	RELAY	Output Relay 14	*	*	*	*
14	see 4B0F	DDB_OUTPUT_RELAY_15	SW	RELAY	Output Relay 15	*	*	*	*
15	see 4B10	DDB_OUTPUT_RELAY_16	SW	RELAY	Output Relay 16	*	*	*	*
16	see 4B11	DDB_OUTPUT_RELAY_17	SW	RELAY	Output Relay 17	*	*	*	*
17	see 4B12	DDB_OUTPUT_RELAY_18	SW	RELAY	Output Relay 18	*	*	*	*
18	see 4B13	DDB_OUTPUT_RELAY_19	SW	RELAY	Output Relay 19	*	*	*	*
19	see 4B14	DDB_OUTPUT_RELAY_20	SW	RELAY	Output Relay 20	*	*	*	*
20	see 4B15	DDB_OUTPUT_RELAY_21	SW	RELAY	Output Relay 21	*	*	*	*
21	see 4B16	DDB_OUTPUT_RELAY_22	SW	RELAY	Output Relay 22	*	*	*	*
22	see 4B17	DDB_OUTPUT_RELAY_23	SW	RELAY	Output Relay 23	*	*	*	*
23	see 4B18	DDB_OUTPUT_RELAY_24	SW	RELAY	Output Relay 24	*	*	*	*
24	see 4B19	DDB_OUTPUT_RELAY_25	SW	RELAY	Output Relay 25		*	*	*
25	see 4B1A	DDB_OUTPUT_RELAY_26	SW	RELAY	Output Relay 26		*	*	*
26	see 4B1B	DDB_OUTPUT_RELAY_27	SW	RELAY	Output Relay 27		*	*	*
27	see 4B1C	DDB_OUTPUT_RELAY_28	SW	RELAY	Output Relay 28		*	*	*
28	see 4B1D	DDB_OUTPUT_RELAY_29	SW	RELAY	Output Relay 29		*	*	*
29	see 4B1E	DDB_OUTPUT_RELAY_30	SW	RELAY	Output Relay 30		*	*	*
30	see 4B1F	DDB_OUTPUT_RELAY_31	SW	RELAY	Output Relay 31		*	*	*
31	see 4B20	DDB_OUTPUT_RELAY_32	SW	RELAY	Output Relay 32		*	*	*
32	see 4A01	DDB_OPTO_ISOLATOR_1	SW	OPTO	Opto Isolator Input 1	*	*	*	*
33	see 4A02	DDB_OPTO_ISOLATOR_2	SW	OPTO	Opto Isolator Input 2	*	*	*	*
34	see 4A03	DDB_OPTO_ISOLATOR_3	SW	OPTO	Opto Isolator Input 3	*	*	*	*
35	see 4A04	DDB_OPTO_ISOLATOR_4	SW	OPTO	Opto Isolator Input 4	*	*	*	*
36	see 4A05	DDB_OPTO_ISOLATOR_5	SW	OPTO	Opto Isolator Input 5	*	*	*	*
37	see 4A06	DDB_OPTO_ISOLATOR_6	SW	OPTO	Opto Isolator Input 6	*	*	*	*
38	see 4A07	DDB_OPTO_ISOLATOR_7	SW	OPTO	Opto Isolator Input 7	*	*	*	*
39	see 4A08	DDB_OPTO_ISOLATOR_8	SW	OPTO	Opto Isolator Input 8	*	*	*	*
40	see 4A09	DDB_OPTO_ISOLATOR_9	SW	OPTO	Opto Isolator Input 9	*	*	*	*
41	see 4A0A	DDB_OPTO_ISOLATOR_10	SW	OPTO	Opto Isolator Input 10	*	*	*	*
42	see 4A0B	DDB_OPTO_ISOLATOR_11	SW	OPTO	Opto Isolator Input 11	*	*	*	*
43	see 4A0C	DDB_OPTO_ISOLATOR_12	SW	OPTO	Opto Isolator Input 12	*	*	*	*
44	see 4A0D	DDB_OPTO_ISOLATOR_13	SW	OPTO	Opto Isolator Input 13	*	*	*	*
45	see 4A0E	DDB_OPTO_ISOLATOR_14	SW	OPTO	Opto Isolator Input 14	*	*	*	*
46	see 4A0F	DDB_OPTO_ISOLATOR_15	SW	OPTO	Opto Isolator Input 15	*	*	*	*
47	see 4A10	DDB_OPTO_ISOLATOR_16	SW	OPTO	Opto Isolator Input 16	*	*	*	*
48	see 4A11	DDB_OPTO_ISOLATOR_17	SW	OPTO	Opto Isolator Input 17	*	*	*	*
49	see 4A12	DDB_OPTO_ISOLATOR_18	SW	OPTO	Opto Isolator Input 18	*	*	*	*
50	see 4A13	DDB_OPTO_ISOLATOR_19	SW	OPTO	Opto Isolator Input 19	*	*	*	*
51	see 4A14	DDB_OPTO_ISOLATOR_20	SW	OPTO	Opto Isolator Input 20	*	*	*	*
52	see 4A15	DDB_OPTO_ISOLATOR_21	SW	OPTO	Opto Isolator Input 21	*	*	*	*
53	see 4A16	DDB_OPTO_ISOLATOR_22	SW	OPTO	Opto Isolator Input 22	*	*	*	*
54	see 4A17	DDB_OPTO_ISOLATOR_23	SW	OPTO	Opto Isolator Input 23	*	*	*	*
55	see 4A18	DDB_OPTO_ISOLATOR_24	SW	OPTO	Opto Isolator Input 24	*	*	*	*
56	see 4A19	DDB_OPTO_ISOLATOR_25	SW	OPTO	Opto Isolator Input 25		*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
57	see 4A1A	DDB_OPTO_ISOLATOR_26	SW	OPTO	Opto Isolator Input 26		*	*	*
58	see 4A1B	DDB_OPTO_ISOLATOR_27	SW	OPTO	Opto Isolator Input 27		*	*	*
59	see 4A1C	DDB_OPTO_ISOLATOR_28	SW	OPTO	Opto Isolator Input 28		*	*	*
60	see 4A1D	DDB_OPTO_ISOLATOR_29	SW	OPTO	Opto Isolator Input 29		*	*	*
61	see 4A1E	DDB_OPTO_ISOLATOR_30	SW	OPTO	Opto Isolator Input 30		*	*	*
62	see 4A1F	DDB_OPTO_ISOLATOR_31	SW	OPTO	Opto Isolator Input 31		*	*	*
63	see 4A20	DDB_OPTO_ISOLATOR_32	SW	OPTO	Opto Isolator Input 32		*	*	*
64	Relay Cond 1	DDB_OUTPUT_CON_1	PSL	OUTPUT_CON	Relay Conditioner 1	*	*	*	*
65	Relay Cond 2	DDB_OUTPUT_CON_2	PSL	OUTPUT_CON	Relay Conditioner 2	*	*	*	*
66	Relay Cond 3	DDB_OUTPUT_CON_3	PSL	OUTPUT_CON	Relay Conditioner 3	*	*	*	*
67	Relay Cond 4	DDB_OUTPUT_CON_4	PSL	OUTPUT_CON	Relay Conditioner 4	*	*	*	*
68	Relay Cond 5	DDB_OUTPUT_CON_5	PSL	OUTPUT_CON	Relay Conditioner 5	*	*	*	*
69	Relay Cond 6	DDB_OUTPUT_CON_6	PSL	OUTPUT_CON	Relay Conditioner 6	*	*	*	*
70	Relay Cond 7	DDB_OUTPUT_CON_7	PSL	OUTPUT_CON	Relay Conditioner 7	*	*	*	*
71	Relay Cond 8	DDB_OUTPUT_CON_8	PSL	OUTPUT_CON	Relay Conditioner 8	*	*	*	*
72	Relay Cond 9	DDB_OUTPUT_CON_9	PSL	OUTPUT_CON	Relay Conditioner 9	*	*	*	*
73	Relay Cond 10	DDB_OUTPUT_CON_10	PSL	OUTPUT_CON	Relay Conditioner 10	*	*	*	*
74	Relay Cond 11	DDB_OUTPUT_CON_11	PSL	OUTPUT_CON	Relay Conditioner 11	*	*	*	*
75	Relay Cond 12	DDB_OUTPUT_CON_12	PSL	OUTPUT_CON	Relay Conditioner 12	*	*	*	*
76	Relay Cond 13	DDB_OUTPUT_CON_13	PSL	OUTPUT_CON	Relay Conditioner 13	*	*	*	*
77	Relay Cond 14	DDB_OUTPUT_CON_14	PSL	OUTPUT_CON	Relay Conditioner 14	*	*	*	*
78	Relay Cond 15	DDB_OUTPUT_CON_15	PSL	OUTPUT_CON	Relay Conditioner 15	*	*	*	*
79	Relay Cond 16	DDB_OUTPUT_CON_16	PSL	OUTPUT_CON	Relay Conditioner 16	*	*	*	*
80	Relay Cond 17	DDB_OUTPUT_CON_17	PSL	OUTPUT_CON	Relay Conditioner 17	*	*	*	*
81	Relay Cond 18	DDB_OUTPUT_CON_18	PSL	OUTPUT_CON	Relay Conditioner 18	*	*	*	*
82	Relay Cond 19	DDB_OUTPUT_CON_19	PSL	OUTPUT_CON	Relay Conditioner 19	*	*	*	*
83	Relay Cond 20	DDB_OUTPUT_CON_20	PSL	OUTPUT_CON	Relay Conditioner 20	*	*	*	*
84	Relay Cond 21	DDB_OUTPUT_CON_21	PSL	OUTPUT_CON	Relay Conditioner 21	*	*	*	*
85	Relay Cond 22	DDB_OUTPUT_CON_22	PSL	OUTPUT_CON	Relay Conditioner 22	*	*	*	*
86	Relay Cond 23	DDB_OUTPUT_CON_23	PSL	OUTPUT_CON	Relay Conditioner 23	*	*	*	*
87	Relay Cond 24	DDB_OUTPUT_CON_24	PSL	OUTPUT_CON	Relay Conditioner 24	*	*	*	*
88	Relay Cond 25	DDB_OUTPUT_CON_25	PSL	OUTPUT_CON	Relay Conditioner 25		*	*	*
89	Relay Cond 26	DDB_OUTPUT_CON_26	PSL	OUTPUT_CON	Relay Conditioner 26		*	*	*
90	Relay Cond 27	DDB_OUTPUT_CON_27	PSL	OUTPUT_CON	Relay Conditioner 27		*	*	*
91	Relay Cond 28	DDB_OUTPUT_CON_28	PSL	OUTPUT_CON	Relay Conditioner 28		*	*	*
92	Relay Cond 29	DDB_OUTPUT_CON_29	PSL	OUTPUT_CON	Relay Conditioner 29		*	*	*
93	Relay Cond 30	DDB_OUTPUT_CON_30	PSL	OUTPUT_CON	Relay Conditioner 30		*	*	*
94	Relay Cond 31	DDB_OUTPUT_CON_31	PSL	OUTPUT_CON	Relay Conditioner 31		*	*	*
95	Relay Cond 32	DDB_OUTPUT_CON_32	PSL	OUTPUT_CON	Relay Conditioner 32		*	*	*
96	LED1 Red	DDB_OUTPUT_TRI_LED_1_RED	SW	TRI_LED	Tri-LED - 1 - Red		*	*	*
97	LED1 Grn	DDB_OUTPUT_TRI_LED_1_GRN	SW	TRI_LED	Tri-LED - 1 - Green		*	*	*
98	LED2 Red	DDB_OUTPUT_TRI_LED_2_RED	SW	TRI_LED	Tri-LED - 2 - Red		*	*	*
99	LED2 Grn	DDB_OUTPUT_TRI_LED_2_GRN	SW	TRI_LED	Tri-LED - 2 - Green		*	*	*
100	LED3 Red	DDB_OUTPUT_TRI_LED_3_RED	SW	TRI_LED	Tri-LED - 3 - Red		*	*	*
101	LED3 Grn	DDB_OUTPUT_TRI_LED_3_GRN	SW	TRI_LED	Tri-LED - 3 - Green		*	*	*
102	LED4 Red	DDB_OUTPUT_TRI_LED_4_RED	SW	TRI_LED	Tri-LED - 4 - Red		*	*	*
103	LED4 Grn	DDB_OUTPUT_TRI_LED_4_GRN	SW	TRI_LED	Tri-LED - 4 - Green		*	*	*
104	LED5 Red	DDB_OUTPUT_TRI_LED_5_RED	SW	TRI_LED	Tri-LED - 5 - Red		*	*	*
105	LED5 Grn	DDB_OUTPUT_TRI_LED_5_GRN	SW	TRI_LED	Tri-LED - 5 - Green		*	*	*
106	LED6 Red	DDB_OUTPUT_TRI_LED_6_RED	SW	TRI_LED	Tri-LED - 6 - Red		*	*	*
107	LED6 Grn	DDB_OUTPUT_TRI_LED_6_GRN	SW	TRI_LED	Tri-LED - 6 - Green		*	*	*
108	LED7 Red	DDB_OUTPUT_TRI_LED_7_RED	SW	TRI_LED	Tri-LED - 7 - Red		*	*	*
109	LED7 Grn	DDB_OUTPUT_TRI_LED_7_GRN	SW	TRI_LED	Tri-LED - 7 - Green		*	*	*
110	LED8 Red	DDB_OUTPUT_TRI_LED_8_RED	SW	TRI_LED	Tri-LED - 8 - Red		*	*	*
111	LED8 Grn	DDB_OUTPUT_TRI_LED_8_GRN	SW	TRI_LED	Tri-LED - 8 - Green		*	*	*
112	FnKey LED1 Red	DDB_OUTPUT_TRI_LED_9_RED	SW	TRI_LED	Tri-LED - 9 - Red		*	*	*
113	FnKey LED1 Grn	DDB_OUTPUT_TRI_LED_9_GRN	SW	TRI_LED	Tri-LED - 9 - Green		*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
114	FnKey LED2 Red	DDB_OUTPUT_TRI_LED_10_RED	SW	TRI_LED	Tri-LED - 10 - Red		*	*	*
115	FnKey LED2 Grn	DDB_OUTPUT_TRI_LED_10_GRN	SW	TRI_LED	Tri-LED - 10 - Green		*	*	*
116	FnKey LED3 Red	DDB_OUTPUT_TRI_LED_11_RED	SW	TRI_LED	Tri-LED - 11 - Red		*	*	*
117	FnKey LED3 Grn	DDB_OUTPUT_TRI_LED_11_GRN	SW	TRI_LED	Tri-LED - 11 - Green		*	*	*
118	FnKey LED4 Red	DDB_OUTPUT_TRI_LED_12_RED	SW	TRI_LED	Tri-LED - 12 - Red		*	*	*
119	FnKey LED4 Grn	DDB_OUTPUT_TRI_LED_12_GRN	SW	TRI_LED	Tri-LED - 12 - Green		*	*	*
120	FnKey LED5 Red	DDB_OUTPUT_TRI_LED_13_RED	SW	TRI_LED	Tri-LED - 13 - Red		*	*	*
121	FnKey LED5 Grn	DDB_OUTPUT_TRI_LED_13_GRN	SW	TRI_LED	Tri-LED - 13 - Green		*	*	*
122	FnKey LED6 Red	DDB_OUTPUT_TRI_LED_14_RED	SW	TRI_LED	Tri-LED - 14 - Red		*	*	*
123	FnKey LED6 Grn	DDB_OUTPUT_TRI_LED_14_GRN	SW	TRI_LED	Tri-LED - 14 - Green		*	*	*
124	FnKey LED7 Red	DDB_OUTPUT_TRI_LED_15_RED	SW	TRI_LED	Tri-LED - 15 - Red		*	*	*
125	FnKey LED7 Grn	DDB_OUTPUT_TRI_LED_15_GRN	SW	TRI_LED	Tri-LED - 15 - Green		*	*	*
126	FnKey LED8 Red	DDB_OUTPUT_TRI_LED_16_RED	SW	TRI_LED	Tri-LED - 16 - Red		*	*	*
127	FnKey LED8 Grn	DDB_OUTPUT_TRI_LED_16_GRN	SW	TRI_LED	Tri-LED - 16 - Green		*	*	*
128	FnKey LED9 Red	DDB_OUTPUT_TRI_LED_17_RED	SW	TRI_LED	Tri-LED - 17 - Red		*	*	*
129	FnKey LED9 Grn	DDB_OUTPUT_TRI_LED_17_GRN	SW	TRI_LED	Tri-LED - 17 - Green		*	*	*
130	FnKey LED10 Red	DDB_OUTPUT_TRI_LED_18_RED	SW	TRI_LED	Tri-LED - 18 - Red		*	*	*
131	FnKey LED10 Grn	DDB_OUTPUT_TRI_LED_18_GRN	SW	TRI_LED	Tri-LED - 18 - Green		*	*	*
132		DDB_UNUSED	SW	UNUSED					
133		DDB_UNUSED	SW	UNUSED					
134		DDB_UNUSED	SW	UNUSED					
135		DDB_UNUSED	SW	UNUSED					
136		DDB_UNUSED	SW	UNUSED					
137		DDB_UNUSED	SW	UNUSED					
138		DDB_UNUSED	SW	UNUSED					
139		DDB_UNUSED	SW	UNUSED					
140		DDB_UNUSED	SW	UNUSED					
141		DDB_UNUSED	SW	UNUSED					
142		DDB_UNUSED	SW	UNUSED					
143		DDB_UNUSED	SW	UNUSED					
144		DDB_UNUSED	SW	UNUSED					
145		DDB_UNUSED	SW	UNUSED					
146		DDB_UNUSED	SW	UNUSED					
147		DDB_UNUSED	SW	UNUSED					
148		DDB_UNUSED	SW	UNUSED					
149		DDB_UNUSED	SW	UNUSED					
150		DDB_UNUSED	SW	UNUSED					
151		DDB_UNUSED	SW	UNUSED					
152		DDB_UNUSED	SW	UNUSED					
153		DDB_UNUSED	SW	UNUSED					
154		DDB_UNUSED	SW	UNUSED					
155		DDB_UNUSED	SW	UNUSED					
156		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
157		DDB_UNUSED	SW	UNUSED					
158		DDB_UNUSED	SW	UNUSED					
159		DDB_UNUSED	SW	UNUSED					
160	LED1 Con R	DDB_TRI_LED_RED_CON_1	PSL	TRI_LED_CON	Tri-LED Conditioner - 1 - Red		*	*	*
161	LED1 Con G	DDB_TRI_LED_GRN_CON_1	PSL	TRI_LED_CON	Tri-LED Conditioner- 1 - Green		*	*	*
162	LED2 Con R	DDB_TRI_LED_RED_CON_2	PSL	TRI_LED_CON	Tri-LED Conditioner - 2 - Red		*	*	*
163	LED2 Con G	DDB_TRI_LED_GRN_CON_2	PSL	TRI_LED_CON	Tri-LED Conditioner - 2 - Green		*	*	*
164	LED3 Con R	DDB_TRI_LED_RED_CON_3	PSL	TRI_LED_CON	Tri-LED Conditioner - 3 - Red		*	*	*
165	LED3 Con G	DDB_TRI_LED_GRN_CON_3	PSL	TRI_LED_CON	Tri-LED Conditioner - 3 - Green		*	*	*
166	LED4 Con R	DDB_TRI_LED_RED_CON_4	PSL	TRI_LED_CON	Tri-LED Conditioner - 4 - Red		*	*	*
167	LED4 Con G	DDB_TRI_LED_GRN_CON_4	PSL	TRI_LED_CON	Tri-LED Conditioner - 4 - Green		*	*	*
168	LED5 Con R	DDB_TRI_LED_RED_CON_5	PSL	TRI_LED_CON	Tri-LED Conditioner - 5 - Red		*	*	*
169	LED5 Con G	DDB_TRI_LED_GRN_CON_5	PSL	TRI_LED_CON	Tri-LED Conditioner - 5 - Green		*	*	*
170	LED6 Con R	DDB_TRI_LED_RED_CON_6	PSL	TRI_LED_CON	Tri-LED Conditioner - 6 - Red		*	*	*
171	LED6 Con G	DDB_TRI_LED_GRN_CON_6	PSL	TRI_LED_CON	Tri-LED Conditioner - 6 - Green		*	*	*
172	LED7 Con R	DDB_TRI_LED_RED_CON_7	PSL	TRI_LED_CON	Tri-LED Conditioner - 7 - Red		*	*	*
173	LED7 Con G	DDB_TRI_LED_GRN_CON_7	PSL	TRI_LED_CON	Tri-LED Conditioner - 7 - Green		*	*	*
174	LED8 Con R	DDB_TRI_LED_RED_CON_8	PSL	TRI_LED_CON	Tri-LED Conditioner - 8 - Red		*	*	*
175	LED8 Con G	DDB_TRI_LED_GRN_CON_8	PSL	TRI_LED_CON	Tri-LED Conditioner - 8 - Green		*	*	*
176	FnKey LED1 ConR	DDB_TRI_LED_RED_CON_9	PSL	TRI_LED_CON	Tri-LED Conditioner - 9 - Red		*	*	*
177	FnKey LED1 ConG	DDB_TRI_LED_GRN_CON_9	PSL	TRI_LED_CON	Tri-LED Conditioner - 9 - Green		*	*	*
178	FnKey LED2 ConR	DDB_TRI_LED_RED_CON_10	PSL	TRI_LED_CON	Tri-LED Conditioner - 10 - Red		*	*	*
179	FnKey LED2 ConG	DDB_TRI_LED_GRN_CON_10	PSL	TRI_LED_CON	Tri-LED Conditioner - 10 - Green		*	*	*
180	FnKey LED3 ConR	DDB_TRI_LED_RED_CON_11	PSL	TRI_LED_CON	Tri-LED Conditioner - 11 - Red		*	*	*
181	FnKey LED3 ConG	DDB_TRI_LED_GRN_CON_11	PSL	TRI_LED_CON	Tri-LED Conditioner - 11 - Green		*	*	*
182	FnKey LED4 ConR	DDB_TRI_LED_RED_CON_12	PSL	TRI_LED_CON	Tri-LED Conditioner - 12 - Red		*	*	*
183	FnKey LED4 ConG	DDB_TRI_LED_GRN_CON_12	PSL	TRI_LED_CON	Tri-LED Conditioner - 12 - Green		*	*	*
184	FnKey LED5 ConR	DDB_TRI_LED_RED_CON_13	PSL	TRI_LED_CON	Tri-LED Conditioner - 13 - Red		*	*	*
185	FnKey LED5 ConG	DDB_TRI_LED_GRN_CON_13	PSL	TRI_LED_CON	Tri-LED Conditioner - 13 - Green		*	*	*
186	FnKey LED6 ConR	DDB_TRI_LED_RED_CON_14	PSL	TRI_LED_CON	Tri-LED Conditioner - 14 - Red		*	*	*
187	FnKey LED6 ConG	DDB_TRI_LED_GRN_CON_14	PSL	TRI_LED_CON	Tri-LED Conditioner - 14 - Green		*	*	*
188	FnKey LED7 ConR	DDB_TRI_LED_RED_CON_15	PSL	TRI_LED_CON	Tri-LED Conditioner - 15 - Red		*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
189	FnKey LED7 ConG	DDB_TRI_LED_GRN_CON_15	PSL	TRI_LED_CON	Tri-LED Conditioner - 15 - Green		*	*	*
190	FnKey LED8 ConR	DDB_TRI_LED_RED_CON_16	PSL	TRI_LED_CON	Tri-LED Conditioner - 16 - Red		*	*	*
191	FnKey LED8 ConG	DDB_TRI_LED_GRN_CON_16	PSL	TRI_LED_CON	Tri-LED Conditioner - 16 - Green		*	*	*
192	FnKey LED9 ConR	DDB_TRI_LED_RED_CON_17	PSL	TRI_LED_CON	Tri-LED Conditioner - 17 - Red		*	*	*
193	FnKey LED9 ConG	DDB_TRI_LED_GRN_CON_17	PSL	TRI_LED_CON	Tri-LED Conditioner - 17 - Green		*	*	*
194	FnKey LED10 ConR	DDB_TRI_LED_RED_CON_18	PSL	TRI_LED_CON	Tri-LED Conditioner - 18 - Red		*	*	*
195	FnKey LED10 ConG	DDB_TRI_LED_GRN_CON_18	PSL	TRI_LED_CON	Tri-LED Conditioner - 18 - Green		*	*	*
196		DDB_UNUSED	SW	UNUSED					
197		DDB_UNUSED	SW	UNUSED					
198		DDB_UNUSED	SW	UNUSED					
199		DDB_UNUSED	SW	UNUSED					
200		DDB_UNUSED	SW	UNUSED					
201		DDB_UNUSED	SW	UNUSED					
202		DDB_UNUSED	SW	UNUSED					
203		DDB_UNUSED	SW	UNUSED					
204		DDB_UNUSED	SW	UNUSED					
205		DDB_UNUSED	SW	UNUSED					
206		DDB_UNUSED	SW	UNUSED					
207		DDB_UNUSED	SW	UNUSED					
208		DDB_UNUSED	SW	UNUSED					
209		DDB_UNUSED	SW	UNUSED					
210		DDB_UNUSED	SW	UNUSED					
211		DDB_UNUSED	SW	UNUSED					
212		DDB_UNUSED	SW	UNUSED					
213		DDB_UNUSED	SW	UNUSED					
214		DDB_UNUSED	SW	UNUSED					
215		DDB_UNUSED	SW	UNUSED					
216		DDB_UNUSED	SW	UNUSED					
217		DDB_UNUSED	SW	UNUSED					
218		DDB_UNUSED	SW	UNUSED					
219		DDB_UNUSED	SW	UNUSED					
220		DDB_UNUSED	SW	UNUSED					
221		DDB_UNUSED	SW	UNUSED					
222		DDB_UNUSED	SW	UNUSED					
223		DDB_UNUSED	SW	UNUSED					
224	LED 1	DDB_OUTPUT_LED_1	SW	LED	LED 1	*			
225	LED 2	DDB_OUTPUT_LED_2	SW	LED	LED 2	*			
226	LED 3	DDB_OUTPUT_LED_3	SW	LED	LED 3	*			
227	LED 4	DDB_OUTPUT_LED_4	SW	LED	LED 4	*			
228	LED 5	DDB_OUTPUT_LED_5	SW	LED	LED 5	*			
229	LED 6	DDB_OUTPUT_LED_6	SW	LED	LED 6	*			
230	LED 7	DDB_OUTPUT_LED_7	SW	LED	LED 7	*			
231	LED 8	DDB_OUTPUT_LED_8	SW	LED	LED 8	*			
232	LED Cond IN 1	DDB_LED_CON_1	PSL	LED_CON	LED Conditioner IN 1	*			
233	LED Cond IN 2	DDB_LED_CON_2	PSL	LED_CON	LED Conditioner IN 2	*			
234	LED Cond IN 3	DDB_LED_CON_3	PSL	LED_CON	LED Conditioner IN 3	*			
235	LED Cond IN 4	DDB_LED_CON_4	PSL	LED_CON	LED Conditioner IN 4	*			
236	LED Cond IN 5	DDB_LED_CON_5	PSL	LED_CON	LED Conditioner IN 5	*			
237	LED Cond IN 6	DDB_LED_CON_6	PSL	LED_CON	LED Conditioner IN 6	*			
238	LED Cond IN 7	DDB_LED_CON_7	PSL	LED_CON	LED Conditioner IN 7	*			
239	LED Cond IN 8	DDB_LED_CON_8	PSL	LED_CON	LED Conditioner IN 8	*			
240	InterMiCOM in 1	DDB_INTERIN_1	SW	INTERIN	InterMiCOM Input bit 1	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
241	InterMiCOM in 2	DDB_INTERIN_2	SW	INTERIN	InterMiCOM Input bit 2	*	*	*	*
242	InterMiCOM in 3	DDB_INTERIN_3	SW	INTERIN	InterMiCOM Input bit 3	*	*	*	*
243	InterMiCOM in 4	DDB_INTERIN_4	SW	INTERIN	InterMiCOM Input bit 4	*	*	*	*
244	InterMiCOM in 5	DDB_INTERIN_5	SW	INTERIN	InterMiCOM Input bit 5	*	*	*	*
245	InterMiCOM in 6	DDB_INTERIN_6	SW	INTERIN	InterMiCOM Input bit 6	*	*	*	*
246	InterMiCOM in 7	DDB_INTERIN_7	SW	INTERIN	InterMiCOM Input bit 7	*	*	*	*
247	InterMiCOM in 8	DDB_INTERIN_8	SW	INTERIN	InterMiCOM Input bit 8	*	*	*	*
248	InterMiCOM out 1	DDB_INTEROUT_1	PSL	INTEROUT	InterMiCOM Output bit 1	*	*	*	*
249	InterMiCOM out 2	DDB_INTEROUT_2	PSL	INTEROUT	InterMiCOM Output bit 2	*	*	*	*
250	InterMiCOM out 3	DDB_INTEROUT_3	PSL	INTEROUT	InterMiCOM Output bit 3	*	*	*	*
251	InterMiCOM out 4	DDB_INTEROUT_4	PSL	INTEROUT	InterMiCOM Output bit 4	*	*	*	*
252	InterMiCOM out 5	DDB_INTEROUT_5	PSL	INTEROUT	InterMiCOM Output bit 5	*	*	*	*
253	InterMiCOM out 6	DDB_INTEROUT_6	PSL	INTEROUT	InterMiCOM Output bit 6	*	*	*	*
254	InterMiCOM out 7	DDB_INTEROUT_7	PSL	INTEROUT	InterMiCOM Output bit 7	*	*	*	*
255	InterMiCOM out 8	DDB_INTEROUT_8	PSL	INTEROUT	InterMiCOM Output bit 8	*	*	*	*
256	Function Key 1	DDB_FN_KEY_1	SW	FUNCTION_KEY	Function Key 1		*	*	*
257	Function Key 2	DDB_FN_KEY_2	SW	FUNCTION_KEY	Function Key 2		*	*	*
258	Function Key 3	DDB_FN_KEY_3	SW	FUNCTION_KEY	Function Key 3		*	*	*
259	Function Key 4	DDB_FN_KEY_4	SW	FUNCTION_KEY	Function Key 4		*	*	*
260	Function Key 5	DDB_FN_KEY_5	SW	FUNCTION_KEY	Function Key 5		*	*	*
261	Function Key 6	DDB_FN_KEY_6	SW	FUNCTION_KEY	Function Key 6		*	*	*
262	Function Key 7	DDB_FN_KEY_7	SW	FUNCTION_KEY	Function Key 7		*	*	*
263	Function Key 8	DDB_FN_KEY_8	SW	FUNCTION_KEY	Function Key 8		*	*	*
264	Function Key 9	DDB_FN_KEY_9	SW	FUNCTION_KEY	Function Key 9		*	*	*
265	Function Key 10	DDB_FN_KEY_10	SW	FUNCTION_KEY	Function Key 10		*	*	*
266		DDB_UNUSED	SW	UNUSED					
267		DDB_UNUSED	SW	UNUSED					
268		DDB_UNUSED	SW	UNUSED					
269		DDB_UNUSED	SW	UNUSED					
270		DDB_UNUSED	SW	UNUSED					
271		DDB_UNUSED	SW	UNUSED					
272		DDB_UNUSED	SW	UNUSED					
273		DDB_UNUSED	SW	UNUSED					
274		DDB_UNUSED	SW	UNUSED					
275		DDB_UNUSED	SW	UNUSED					
276		DDB_UNUSED	SW	UNUSED					
277		DDB_UNUSED	SW	UNUSED					
278		DDB_UNUSED	SW	UNUSED					
279		DDB_UNUSED	SW	UNUSED					
280		DDB_UNUSED	SW	UNUSED					
281		DDB_UNUSED	SW	UNUSED					
282		DDB_UNUSED	SW	UNUSED					
283		DDB_UNUSED	SW	UNUSED					
284		DDB_UNUSED	SW	UNUSED					
285		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
286		DDB_UNUSED	SW	UNUSED					
287		DDB_UNUSED	SW	UNUSED					
288	Timer out 1	DDB_TIMEROUT_1	SW	TIMEROUT	Auxiliary Timer out 1	*	*	*	*
289	Timer out 2	DDB_TIMEROUT_2	SW	TIMEROUT	Auxiliary Timer out 2	*	*	*	*
290	Timer out 3	DDB_TIMEROUT_3	SW	TIMEROUT	Auxiliary Timer out 3	*	*	*	*
291	Timer out 4	DDB_TIMEROUT_4	SW	TIMEROUT	Auxiliary Timer out 4	*	*	*	*
292	Timer out 5	DDB_TIMEROUT_5	SW	TIMEROUT	Auxiliary Timer out 5	*	*	*	*
293	Timer out 6	DDB_TIMEROUT_6	SW	TIMEROUT	Auxiliary Timer out 6	*	*	*	*
294	Timer out 7	DDB_TIMEROUT_7	SW	TIMEROUT	Auxiliary Timer out 7	*	*	*	*
295	Timer out 8	DDB_TIMEROUT_8	SW	TIMEROUT	Auxiliary Timer out 8	*	*	*	*
296	Timer out 9	DDB_TIMEROUT_9	SW	TIMEROUT	Auxiliary Timer out 9	*	*	*	*
297	Timer out 10	DDB_TIMEROUT_10	SW	TIMEROUT	Auxiliary Timer out 10	*	*	*	*
298	Timer out 11	DDB_TIMEROUT_11	SW	TIMEROUT	Auxiliary Timer out 11	*	*	*	*
299	Timer out 12	DDB_TIMEROUT_12	SW	TIMEROUT	Auxiliary Timer out 12	*	*	*	*
300	Timer out 13	DDB_TIMEROUT_13	SW	TIMEROUT	Auxiliary Timer out 13	*	*	*	*
301	Timer out 14	DDB_TIMEROUT_14	SW	TIMEROUT	Auxiliary Timer out 14	*	*	*	*
302	Timer out 15	DDB_TIMEROUT_15	SW	TIMEROUT	Auxiliary Timer out 15	*	*	*	*
303	Timer out 16	DDB_TIMEROUT_16	SW	TIMEROUT	Auxiliary Timer out 16	*	*	*	*
304		DDB_UNUSED	SW	UNUSED					
305		DDB_UNUSED	SW	UNUSED					
306		DDB_UNUSED	SW	UNUSED					
307		DDB_UNUSED	SW	UNUSED					
308		DDB_UNUSED	SW	UNUSED					
309		DDB_UNUSED	SW	UNUSED					
310		DDB_UNUSED	SW	UNUSED					
311		DDB_UNUSED	SW	UNUSED					
312		DDB_UNUSED	SW	UNUSED					
313		DDB_UNUSED	SW	UNUSED					
314		DDB_UNUSED	SW	UNUSED					
315		DDB_UNUSED	SW	UNUSED					
316		DDB_UNUSED	SW	UNUSED					
317		DDB_UNUSED	SW	UNUSED					
318		DDB_UNUSED	SW	UNUSED					
319		DDB_UNUSED	SW	UNUSED					
320	Timer in 1	DDB_TIMERIN_1	PSL	TIMERIN	Auxiliary Timer in 1	*	*	*	*
321	Timer in 2	DDB_TIMERIN_2	PSL	TIMERIN	Auxiliary Timer in 2	*	*	*	*
322	Timer in 3	DDB_TIMERIN_3	PSL	TIMERIN	Auxiliary Timer in 3	*	*	*	*
323	Timer in 4	DDB_TIMERIN_4	PSL	TIMERIN	Auxiliary Timer in 4	*	*	*	*
324	Timer in 5	DDB_TIMERIN_5	PSL	TIMERIN	Auxiliary Timer in 5	*	*	*	*
325	Timer in 6	DDB_TIMERIN_6	PSL	TIMERIN	Auxiliary Timer in 6	*	*	*	*
326	Timer in 7	DDB_TIMERIN_7	PSL	TIMERIN	Auxiliary Timer in 7	*	*	*	*
327	Timer in 8	DDB_TIMERIN_8	PSL	TIMERIN	Auxiliary Timer in 8	*	*	*	*
328	Timer in 9	DDB_TIMERIN_9	PSL	TIMERIN	Auxiliary Timer in 9	*	*	*	*
329	Timer in 10	DDB_TIMERIN_10	PSL	TIMERIN	Auxiliary Timer in 10	*	*	*	*
330	Timer in 11	DDB_TIMERIN_11	PSL	TIMERIN	Auxiliary Timer in 11	*	*	*	*
331	Timer in 12	DDB_TIMERIN_12	PSL	TIMERIN	Auxiliary Timer in 12	*	*	*	*
332	Timer in 13	DDB_TIMERIN_13	PSL	TIMERIN	Auxiliary Timer in 13	*	*	*	*
333	Timer in 14	DDB_TIMERIN_14	PSL	TIMERIN	Auxiliary Timer in 14	*	*	*	*
334	Timer in 15	DDB_TIMERIN_15	PSL	TIMERIN	Auxiliary Timer in 15	*	*	*	*
335	Timer in 16	DDB_TIMERIN_16	PSL	TIMERIN	Auxiliary Timer in 16	*	*	*	*
336		DDB_UNUSED	SW	UNUSED					
337		DDB_UNUSED	SW	UNUSED					
338		DDB_UNUSED	SW	UNUSED					
339		DDB_UNUSED	SW	UNUSED					
340		DDB_UNUSED	SW	UNUSED					
341		DDB_UNUSED	SW	UNUSED					
342		DDB_UNUSED	SW	UNUSED					
343		DDB_UNUSED	SW	UNUSED					
344		DDB_UNUSED	SW	UNUSED					
345		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
346		DDB_UNUSED	SW	UNUSED					
347		DDB_UNUSED	SW	UNUSED					
348		DDB_UNUSED	SW	UNUSED					
349		DDB_UNUSED	SW	UNUSED					
350		DDB_UNUSED	SW	UNUSED					
351		DDB_UNUSED	SW	UNUSED					
352		DDB_UNUSED	SW	UNUSED					
353	F out of Range	DDB_FREQ_ALARM	FL	PFSO	Frequency Out of Range	*	*	*	*
354	SG-DDB Invalid	DDB_ILLEGAL_OPTO_SETTINGS_GROUP	SW	PFSO	Setting Group selection by DDB inputs invalid	*	*	*	*
355	Prot'n Disabled	DDB_OOS_ALARM	SW	PFSO	Test Mode Enabled	*	*	*	*
356	VT Fail Alarm	DDB_VTS_INDICATION	SW	PFSO	VTS VT Fail Alarm	*	*	*	*
357	CT-1 Fail Alarm	DDB_CTS_INDICATION	SW	PFSO	CTS-1 CT-1 Fail Alarm	*	*	*	*
358	CB Fail Alarm	DDB_BREAKER_FAIL_ALARM	SW	PFSO	Breaker Fail Any Trip	*	*	*	*
359	I^ Maint Alarm	DDB_BROKEN_CURRENT_ALARM	SW	PFSO	Broken Current Maintenance Alarm	*	*	*	*
360	I^ Lockout Alarm	DDB_BROKEN_CURRENT_LOCKOUT	SW	PFSO	Broken Current Lockout Alarm	*	*	*	*
361	CB Ops Maint	DDB_MAINTENANCE_ALARM	SW	PFSO	Number of CB Operations Maintenance Alarm	*	*	*	*
362	CB Ops Lockout	DDB_MAINTENANCE_LOCKOUT	SW	PFSO	Number of CB Operations Maintenance Lockout	*	*	*	*
363	CB Op Time Maint	DDB_EXCESSIVE_OP_TIME_ALARM	SW	PFSO	Excessive CB Operation Time Maintenance Alarm	*	*	*	*
364	CB Op Time Lock	DDB_EXCESSIVE_OP_TIME_LOCKOUT	SW	PFSO	Excessive CB Operation Time Lockout Alarm	*	*	*	*
365	Fault Freq Lock	DDB_EFF_LOCKOUT	SW	PFSO	Excessive Fault Frequency Lockout Alarm	*	*	*	*
366	CB Status Alarm	DDB_CB_STATUS_ALARM	SW	PFSO	CB Status Alarm	*	*	*	*
367	Man CB Trip Fail	DDB_CB_FAILED_TO_TRIP	SW	PFSO	CB Failed to Trip	*	*	*	*
368	Man CB Cls Fail	DDB_CB_FAILED_TO_CLOSE	SW	PFSO	CB Failed to Close	*	*	*	*
369	Man CB Unhealthy	DDB_CONTROL_CB_UNHEALTHY	SW	PFSO	Control CB Unhealthy	*	*	*	*
370	NPS Thermal Alm	DDB_NPS_ALARM	SW	PFSO	Negative Phase Sequence thermal Alarm	*	*	*	*
371	Gen Thermal Alm	DDB_GEN_THERMAL_ALARM	SW	PFSO	Thermal Overload Alarm	*	*	*	*
372	V/Hz Alarm	DDB_VPERHZ_ALARM	SW	PFSO	Volts Per Hz Alarm	*	*	*	*
373	Field Fail Alarm	DDB_FIELDF_ALARM	SW	PFSO	Field Failure Alarm	*	*	*	*
374	RTD Thermal Alm	DDB_RTD_ALARM	FL	PFSO	RTD Thermal Alarm	*	*	*	*
375	RTD Open Cct	DDB_RTD_OPEN_CCT	SW	PFSO	RTD Open Circuit Failure	*	*	*	*
376	RTD short Cct	DDB_RTD_SHORT_CCT	SW	PFSO	RTD Short Circuit Failure	*	*	*	*
377	RTD Data Error	DDB_RTD_DATA_ERROR	SW	PFSO	RTD Data Inconsistency Error	*	*	*	*
378	RTD Board Fail	DDB_RTD_BOARD_FAILURE	SW	PFSO	RTD Board Failure	*	*	*	*
379	Freq Prot Alm	DDB_FREQ_PROT_ALM	PSL	PFSI	Frequency Protection Alarm	*	*	*	*
380	Voltage Prot Alm	DDB_VOLTAGE_PROT_ALM	PSL	PFSI	Voltage Protection Alarm	*	*	*	*
381	CT-2 Fail Alarm	DDB_CTS_2_INDICATION	SW	PFSO	CTS-2 CT-2 Fail Alarm		*	*	*
382	64S R<1 Alarm	DDB_STEFI_UR_1_TRIP	SW	PFSO	64S 100% St EF Under Resistance Stage 1 Alarm				*
383	64S Fail Alarm	DDB_STEFI_FAIL_ALARM	PSL	PFSI	64S Injection Fail Alarm				*
384	CL Card I/P Fail	DDB_CLIO_CARD_INPUT_FAIL	SW	PFSO	CLIO Input Board Failure	*	*	*	*
385	CL Card O/P Fail	DDB_CLIO_CARD_OUTPUT_FAIL	SW	PFSO	CLIO Output Board Failure	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
386	CL Input 1 Alarm	DDB_CL_INPUT_1_ALARM	SW	PFSO	Current Loop Input 1 Alarm	*	*	*	*
387	CL Input 2 Alarm	DDB_CL_INPUT_2_ALARM	SW	PFSO	Current Loop Input 2 Alarm	*	*	*	*
388	CL Input 3 Alarm	DDB_CL_INPUT_3_ALARM	SW	PFSO	Current Loop Input 3 Alarm	*	*	*	*
389	CL Input 4 Alarm	DDB_CL_INPUT_4_ALARM	SW	PFSO	Current Loop Input 4 Alarm	*	*	*	*
390	CLI1 I< Fail Alm	DDB_CLI_1_UNDERCURRENT_ALARM	SW	PFSO	Current Loop Input 1 Undercurrent Fail Alarm	*	*	*	*
391	CLI2 I< Fail Alm	DDB_CLI_2_UNDERCURRENT_ALARM	SW	PFSO	Current Loop Input 2 Undercurrent Fail Alarm	*	*	*	*
392	CLI3 I< Fail Alm	DDB_CLI_3_UNDERCURRENT_ALARM	SW	PFSO	Current Loop Input 3 Undercurrent Fail Alarm	*	*	*	*
393	CLI4 I< Fail Alm	DDB_CLI_4_UNDERCURRENT_ALARM	SW	PFSO	Current Loop Input 4 Undercurrent Fail Alarm	*	*	*	*
394	64R R<1 Alarm	DDB_64R_UR_1_TRIP	SW	PFSO	64R Rotor EF Under Resistance Stage 1 Alarm	*	*	*	*
395	64R CL I/P Fail	DDB_64R_CLIO_INPUT_FAIL	SW	PFSO	64R Rotor EF Current Loop Input Fail	*	*	*	*
396	CT Mismatch Alm	DDB_CT_PARA_MISMATCH_ALARM	SW	PFSO	CT parameter mismatch alarm		*	*	*
396	Amb T Fail Alm	DDB_DLR_UC_AMBT_TEMP_ALARM	SW	PFSO	DLR Input Ambient Temperature Fail alarm				
397	Loss of Life Alm	DDB_LOL_ALARM	SW	PFSO	Loss of Life Alarm	*	*	*	*
397	Wind V Fail Alm	DDB_DLR_UC_WIND_V_ALARM	SW	PFSO	DLR Input Wind Velocity Fail alarm				
398	FAA Alarm	DDB_FAA_ALARM	SW	PFSO	Aging Acceleration Factor Alarm	*	*	*	*
398	Wind D Fail Alm	DDB_DLR_UC_WIND_DIRECT_ALARM	SW	PFSO	DLR Input Wind Direction Fail alarm				
399	Thru Fault Alm	DDB_THROUGH_FAULT_ALARM	SW	PFSO	Through Fault Alarm	*	*	*	*
399	Solar R Fail Alm	DDB_DLR_UC_SOLAR_RAD_ALARM	SW	PFSO	DLR Input Solar Radiation Fail alarm				
400	Circuit Flt Alm	DDB_CIRCUITRY_FLT_ALM	SW	PFSO	Circuitry Fault Alarm		*	*	*
401	XThermPretrp Alm	DDB_TOL_PRETRIP_ALARM	SW	PFSO	Tol Pretrip Alm	*	*	*	*
402	Diff CTS Alarm	DDB_DIFF_CTS_INDICATION	SW	PFSO	differential CTS		*	*	*
403	Man No Checksync	DDB_CONTROL_NO_CHECK_SYNC	SW	PFSO	Manual close CB but do not satisfy CS condition	*	*	*	*
404	System Split Alm	DDB_SYSTEM_SPLIT_ALARM	SW	PFSO	System Split Alarm	*	*	*	*
405		DDB_UNUSED	SW	UNUSED		*	*	*	*
406		DDB_UNUSED	SW	UNUSED		*	*	*	*
407		DDB_UNUSED	SW	UNUSED		*	*	*	*
408		DDB_UNUSED	SW	UNUSED		*	*	*	*
409		DDB_UNUSED	SW	UNUSED		*	*	*	*
410		DDB_UNUSED	SW	UNUSED		*	*	*	*
411		DDB_UNUSED	SW	UNUSED		*	*	*	*
412		DDB_UNUSED	SW	UNUSED		*	*	*	*
413		DDB_UNUSED	SW	UNUSED		*	*	*	*
414		DDB_UNUSED	SW	UNUSED		*	*	*	*
415		DDB_UNUSED	SW	UNUSED		*	*	*	*
416	Battery Fail	DDB_BATTERY_FAIL_ALARM	SW	PFSO	Battery Fail alarm indication	*	*	*	*
417	Field Volts Fail	DDB_FIELD_VOLTS_FAIL	SW	PFSO	Field Voltage Failure	*	*	*	*
418	Rear Comm 2 Fail	DDB_INTERMICOM_FAIL_ALARM	SW	PFSO	InterMiCOM Second rear comm card failure indication	*	*	*	*
419	GOOSE IED Absent	DDB_GOOSE_MISSING_IED_ALARM	SW	PFSO	Enrolled GOOSE IED absent alarm indication	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
420	NIC Not Fitted	DDB_ECARD_NOT_FITTED_ALARM	SW	PFSO	Network Interface Card not fitted/failed alarm	*	*	*	*
421	NIC No Response	DDB_NIC_NOT_RESPONDING_ALARM	SW	PFSO	Network Interface Card not responding alarm	*	*	*	*
422	NIC Fatal Error	DDB_NIC_FATAL_ERROR_ALARM	SW	PFSO	Network Interface Card fatal error alarm indication	*	*	*	*
423	NIC Soft. Reload	DDB_NIC_SOFTWARE_RELOAD_ALARM	SW	PFSO	Network Interface Card software reload alarm	*	*	*	*
424	Bad TCP/IP Cfg.	DDB_INVALID_TCP_IP_CONFIG_ALARM	SW	PFSO	Bad TCP/IP Configuration Alarm	*	*	*	*
425	Bad OSI Config.	DDB_INVALID_OSI_CONFIG_ALARM	SW	PFSO	Bad OSI Configuration Alarm	*	*	*	*
426		DDB_UNUSED	SW	UNUSED					
427	NIC SW Mis-Match	DDB_SW_MISMATCH_ALARM	SW	PFSO	Main card/NIC software mismatch alarm indication	*	*	*	*
428	IP Addr Conflict	DDB_IP_ADDRESS_CONFLICT_ALARM	SW	PFSO	IP address conflict alarm indication	*	*	*	*
429	IM Loopback	DDB_INTERIN_LOOPBACK_ALARM	SW	PFSO	InterMiCOM Loop-back alarm indication	*	*	*	*
430	IM Message Fail	DDB_INTERIN_MSG_FAIL_ALARM	SW	PFSO	InterMiCOM Message Fail alarm indication	*	*	*	*
431	IM Data CD Fail	DDB_INTERIN_DCD_FAIL_ALARM	SW	PFSO	InterMiCOM DCD Fail alarm indication	*	*	*	*
432	IM Channel Fail	DDB_INTERIN_CHAN_FAIL_ALARM	SW	PFSO	InterMiCOM Channel Fail alarm indication	*	*	*	*
433		DDB_UNUSED	SW	UNUSED					
434		DDB_UNUSED	SW	UNUSED					
435		DDB_UNUSED	SW	UNUSED					
436		DDB_UNUSED	SW	UNUSED					
437	Invalid DNPoE IP	DDB_INVALID_DNPOE_IP_ALARM	SW	PFSO	Invalid DNPoE IP Configuration Alarm	*	*	*	*
438	Invalid Config.	DDB_INVALID_CONFIG_ALARM	SW	PFSO	Invalid IEC61850 Configuration Alarm	*	*	*	*
439	Test Mode Alm	DDB_TEST_MODE_ALARM	SW	PFSO	Test Mode Activated Alarm	*	*	*	*
440	contacts Blk Alm	DDB_CONT_BLK_ALARM	SW	PFSO	Contacts Blocked Alarm	*	*	*	*
441	NIC HW Mis-Match	DDB_HW_MISMATCH_ALARM	SW	PFSO	Main card/Ethernet card hw option mismatch Alarm	*	*	*	*
442	NIC Ed Mis-Match	DDB_IEC61850_VER_MISMATCH_ALARM	SW	PFSO	Main card/Ethernet card IEC61850 ver mismatch Alarm	*	*	*	*
443	Simul.GOOSE Alm	DDB_GS_ACEPT_SIMU_ALM	SW	PFSO	IEC 61850 accept simulation GOOSE alarm	*	*	*	*
444		DDB_UNUSED	SW	UNUSED					
445		DDB_UNUSED	SW	UNUSED					
446		DDB_UNUSED	SW	UNUSED					
447		DDB_UNUSED	SW	UNUSED					
448		DDB_UNUSED	SW	UNUSED					
449		DDB_UNUSED	SW	UNUSED					
450		DDB_UNUSED	SW	UNUSED					
451		DDB_UNUSED	SW	UNUSED					
452		DDB_UNUSED	SW	UNUSED					
453		DDB_UNUSED	SW	UNUSED					
454		DDB_UNUSED	SW	UNUSED					
455		DDB_UNUSED	SW	UNUSED					
456		DDB_UNUSED	SW	UNUSED					
457		DDB_UNUSED	SW	UNUSED					
458		DDB_UNUSED	SW	UNUSED					
459		DDB_UNUSED	SW	UNUSED					
460		DDB_UNUSED	SW	UNUSED					
461		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
462		DDB_UNUSED	SW	UNUSED					
463		DDB_UNUSED	SW	UNUSED					
464		DDB_UNUSED	SW	UNUSED					
465		DDB_UNUSED	SW	UNUSED					
466		DDB_UNUSED	SW	UNUSED					
467		DDB_UNUSED	SW	UNUSED					
468		DDB_UNUSED	SW	UNUSED					
469		DDB_UNUSED	SW	UNUSED					
470		DDB_UNUSED	SW	UNUSED					
471		DDB_UNUSED	SW	UNUSED					
472		DDB_UNUSED	SW	UNUSED					
473		DDB_UNUSED	SW	UNUSED					
474		DDB_UNUSED	SW	UNUSED					
475		DDB_UNUSED	SW	UNUSED					
476		DDB_UNUSED	SW	UNUSED					
477		DDB_UNUSED	SW	UNUSED					
478		DDB_UNUSED	SW	UNUSED					
479		DDB_UNUSED	SW	UNUSED					
480		DDB_UNUSED	SW	UNUSED					
481		DDB_UNUSED	SW	UNUSED					
482		DDB_UNUSED	SW	UNUSED					
483		DDB_UNUSED	SW	UNUSED					
484		DDB_UNUSED	SW	UNUSED					
485		DDB_UNUSED	SW	UNUSED					
486		DDB_UNUSED	SW	UNUSED					
487		DDB_UNUSED	SW	UNUSED					
488		DDB_UNUSED	SW	UNUSED					
489		DDB_UNUSED	SW	UNUSED					
490		DDB_UNUSED	SW	UNUSED					
491		DDB_UNUSED	SW	UNUSED					
492		DDB_UNUSED	SW	UNUSED					
493		DDB_UNUSED	SW	UNUSED					
494		DDB_UNUSED	SW	UNUSED					
495		DDB_UNUSED	SW	UNUSED					
496		DDB_UNUSED	SW	UNUSED					
497		DDB_UNUSED	SW	UNUSED					
498		DDB_UNUSED	SW	UNUSED					
499		DDB_UNUSED	SW	UNUSED					
500		DDB_UNUSED	SW	UNUSED					
501		DDB_UNUSED	SW	UNUSED					
502		DDB_UNUSED	SW	UNUSED					
503		DDB_UNUSED	SW	UNUSED					
504		DDB_UNUSED	SW	UNUSED					
505		DDB_UNUSED	SW	UNUSED					
506		DDB_UNUSED	SW	UNUSED					
507		DDB_UNUSED	SW	UNUSED					
508		DDB_UNUSED	SW	UNUSED					
509		DDB_UNUSED	SW	UNUSED					
510		DDB_UNUSED	SW	UNUSED					
511		DDB_UNUSED	SW	UNUSED					
512	Gen Diff Block	DDB_GENDIFF_BLOCK	PSL	PFSI	Block Generator Differential protection		*	*	*
513	Xform Diff Block	DDB_BLK_XFORMER_DIFF	PSL	PFSI	Block Xformer Differential protection		*	*	*
514	Inhibit Diff CTS	DDB_DIFF_INHIBIT_CTS	PSL	PFSI	differential CTS		*	*	*
515		DDB_UNUSED	SW	UNUSED					
516		DDB_UNUSED	SW	UNUSED					
517		DDB_UNUSED	SW	UNUSED					
518		DDB_UNUSED	SW	UNUSED					
519		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
520		DDB_UNUSED	SW	UNUSED					
521		DDB_UNUSED	SW	UNUSED					
522		DDB_UNUSED	SW	UNUSED					
523		DDB_UNUSED	SW	UNUSED					
524		DDB_UNUSED	SW	UNUSED					
525		DDB_UNUSED	SW	UNUSED					
526		DDB_UNUSED	SW	UNUSED					
527		DDB_UNUSED	SW	UNUSED					
528		DDB_UNUSED	SW	UNUSED					
529		DDB_UNUSED	SW	UNUSED					
530		DDB_UNUSED	SW	UNUSED					
531		DDB_UNUSED	SW	UNUSED					
532		DDB_UNUSED	SW	UNUSED					
533		DDB_UNUSED	SW	UNUSED					
534		DDB_UNUSED	SW	UNUSED					
535		DDB_UNUSED	SW	UNUSED					
536		DDB_UNUSED	SW	UNUSED					
537		DDB_UNUSED	SW	UNUSED					
538		DDB_UNUSED	SW	UNUSED					
539		DDB_UNUSED	SW	UNUSED					
540		DDB_UNUSED	SW	UNUSED					
541		DDB_UNUSED	SW	UNUSED					
542		DDB_UNUSED	SW	UNUSED					
543		DDB_UNUSED	SW	UNUSED					
544	IN>1 Timer Blk	DDB_EF1_1_TIMER_BLOCK	PSL	PFSI	Block Earth Fault Stage 1 time delay	*	*	*	*
545	IN>2 Timer Blk	DDB_EF1_2_TIMER_BLOCK	PSL	PFSI	Block Earth Fault Stage 2 time delay	*	*	*	*
546	IN>3 Timer Blk	DDB_EF1_3_TIMER_BLOCK	PSL	PFSI	Block Earth Fault Stage 3 time delay				
547	IN>4 Timer Blk	DDB_EF1_4_TIMER_BLOCK	PSL	PFSI	Block Earth Fault Stage 4 time delay				
548	ISEF>1 Timer Blk	DDB_SEF_1_TIMER_BLOCK	PSL	PFSI	Block SEF Stage 1 time delay	*	*	*	*
549	ISEF>2 Timer Blk	DDB_SEF_2_TIMER_BLOCK	PSL	PFSI	Block SEF Stage 2 time delay				
550	ISEF>3 Timer Blk	DDB_SEF_3_TIMER_BLOCK	PSL	PFSI	Block SEF Stage 3 time delay				
551	ISEF>4 Timer Blk	DDB_SEF_4_TIMER_BLOCK	PSL	PFSI	Block SEF Stage 4 time delay				
552	64S I>1 Inhibit	DDB_STEFI_OC_1_INHIBIT	PSL	PFSI	Inhibit 64S Overcurrent Protection				*
553	64S R<1 Inhibit	DDB_STEFI_UR_1_INHIBIT	PSL	PFSI	Inhibit 64S Under Impedance Stage 1				*
554	64S R<2 Inhibit	DDB_STEFI_UR_2_INHIBIT	PSL	PFSI	Inhibit 64S Under Impedance Stage 2				*
555	64S Filter On	DDB_STEFI_FILTER_ON	PSL	PFSI	Enable the 64S band pass filter permanently				*
556	64R R<1 Inhibit	DDB_64R_UR_1_INHIBIT	PSL	PFSI	Inhibit 64R Under Impedance Stage 1	*	*	*	*
557	64R R<2 Inhibit	DDB_64R_UR_2_INHIBIT	PSL	PFSI	Inhibit 64R Under Impedance Stage 2	*	*	*	*
558		DDB_UNUSED	SW	UNUSED					
559		DDB_UNUSED	SW	UNUSED					
560		DDB_UNUSED	SW	UNUSED					
561		DDB_UNUSED	SW	UNUSED					
562		DDB_UNUSED	SW	UNUSED					
563		DDB_UNUSED	SW	UNUSED					
564		DDB_UNUSED	SW	UNUSED					
565		DDB_UNUSED	SW	UNUSED					
566		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
567		DDB_UNUSED	SW	UNUSED					
568		DDB_UNUSED	SW	UNUSED					
569		DDB_UNUSED	SW	UNUSED					
570		DDB_UNUSED	SW	UNUSED					
571		DDB_UNUSED	SW	UNUSED					
572		DDB_UNUSED	SW	UNUSED					
573		DDB_UNUSED	SW	UNUSED					
574		DDB_UNUSED	SW	UNUSED					
575		DDB_UNUSED	SW	UNUSED					
576	I>1 Timer Block	DDB_POC_1_TIMER_BLOCK	PSL	PFSI	Block Phase Overcurrent Stage 1 time delay	*	*	*	*
577	I>2 Timer Block	DDB_POC_2_TIMER_BLOCK	PSL	PFSI	Block Phase Overcurrent Stage 2 time delay	*	*	*	*
578	I>3 Timer Block	DDB_POC_3_TIMER_BLOCK	PSL	PFSI	Block Phase Overcurrent Stage 3 time delay	*	*	*	*
579	I>4 Timer Block	DDB_POC_4_TIMER_BLOCK	PSL	PFSI	Block Phase Overcurrent Stage 4 time delay	*	*	*	*
580		DDB_UNUSED	SW	UNUSED					
581		DDB_UNUSED	SW	UNUSED					
582	I2> Inhibit	DDB_NPSOC_INHIBIT	PSL	PFSI	Inhibit NPS Overcurrent protection	*	*	*	*
583	I2>1 Timer Block	DDB_NPSOC_1_TIMER_BLOCK	PSL	PFSI	Block NPS Overcurrent Stage 1 Timer	*	*	*	*
584	I2>2 Timer Block	DDB_NPSOC_2_TIMER_BLOCK	PSL	PFSI	Block NPS Overcurrent Stage 2 Timer	*	*	*	*
585	I2>3 Timer Block	DDB_NPSOC_3_TIMER_BLOCK	PSL	PFSI	Block NPS Overcurrent Stage 3 Timer	*	*	*	*
586	I2>4 Timer Block	DDB_NPSOC_4_TIMER_BLOCK	PSL	PFSI	Block NPS Overcurrent Stage 4 Timer	*	*	*	*
587		DDB_UNUSED	SW	UNUSED					
588		DDB_UNUSED	SW	UNUSED					
589		DDB_UNUSED	SW	UNUSED					
590		DDB_UNUSED	SW	UNUSED					
591		DDB_UNUSED	SW	UNUSED					
592	VN>1 Timer Blk	DDB_RESOV_1_TIMER_BLOCK	PSL	PFSI	Block Residual Over Voltage Stage 1 time delay	*	*	*	*
593	VN>2 Timer Blk	DDB_RESOV_2_TIMER_BLOCK	PSL	PFSI	Block Residual Over Voltage Stage 2 time delay	*	*	*	*
594	VN>3 Timer Block	DDB_RESOV_3_TIMER_BLOCK	PSL	PFSI	Block Residual Over Voltage Stage 3 Timer	*	*	*	*
595	VN>4 Timer Block	DDB_RESOV_4_TIMER_BLOCK	PSL	PFSI	Block Residual Over Voltage Stage 4 Timer	*	*	*	*
596	VN>5 Timer Block	DDB_RESOV_5_TIMER_BLOCK	PSL	PFSI	Block Residual Over Voltage Stage 5 Timer			*	*
597	VN>6 Timer Block	DDB_RESOV_6_TIMER_BLOCK	PSL	PFSI	Block Residual Over Voltage Stage 6 Timer			*	*
598	V>1 Timer Block	DDB_POV_1_TIMER_BLOCK	PSL	PFSI	Block Phase Over Voltage Stage 1 time delay	*	*	*	*
599	V>2 Timer Block	DDB_POV_2_TIMER_BLOCK	PSL	PFSI	Block Phase Over Voltage Stage 2 time delay	*	*	*	*
600	V2>1 Accelerate	DDB_NPSOV_1_ACCELERATE	PSL	PFSI	Accelerate NPS Over Voltage Stage 1 Start	*	*	*	*
601	V<1 Timer Block	DDB_PUV_1_TIMER_BLOCK	PSL	PFSI	Block Phase Under Voltage Stage 1 time delay	*	*	*	*
602	V<2 Timer Block	DDB_PUV_2_TIMER_BLOCK	PSL	PFSI	Block Phase Under Voltage Stage 2 time delay	*	*	*	*
603	V2>1 Accelerate	DDB_NPSOV_1_ACCELERATE	PSL	PFSI	Accelerate NPS Over Voltage Stage 1 Start				
604		DDB_UNUSED	SW	UNUSED					
605		DDB_UNUSED	SW	UNUSED					
606		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
607		DDB_UNUSED	SW	UNUSED					
608	VDepOC Timer Blk	DDB_VOLT_DEP_OC_TIMER_BLOCK	PSL	PFSI	Voltage Dependant Overcurrent time delay	*	*	*	*
609	UnderZ Timer Blk	DDB_UNDERZ_TIMER_BLOCK	PSL	PFSI	Under Impedance time delay	*	*	*	*
610	=T(AH618)	DDB_IRIGB_SIGNAL_VALID	SW	PFSO	IRIG-B Status Signal Valid	*	*	*	*
611		DDB_UNUSED	SW	UNUSED					
612		DDB_UNUSED	SW	UNUSED					
613		DDB_UNUSED	SW	UNUSED					
614		DDB_UNUSED	SW	UNUSED					
615		DDB_UNUSED	SW	UNUSED					
616		DDB_UNUSED	SW	UNUSED					
617		DDB_UNUSED	SW	UNUSED					
618		DDB_UNUSED	SW	UNUSED					
619		DDB_UNUSED	SW	UNUSED					
620		DDB_UNUSED	SW	UNUSED					
621		DDB_UNUSED	SW	UNUSED					
622		DDB_UNUSED	SW	UNUSED					
623		DDB_UNUSED	SW	UNUSED					
624	Stop Freq Track	DDB_FREQ_STOP_TRACK	PSL	HIDDEN	Stop / Halt Frequency Tracking	*	*	*	*
625	V/Hz>1 Inhibit	DDB_VPERHZ_TRIP1_INH	PSL	PFSI	Inhibit Volts per Hz Stage 1	*	*	*	*
626	F<1 Timer Block	DDB_UFREQ_1_TIMER_BLOCK	PSL	PFSI	Block Under Frequency Stage 1 Timer	*	*	*	*
627	F<2 Timer Block	DDB_UFREQ_2_TIMER_BLOCK	PSL	PFSI	Block Under Frequency Stage 2 Timer	*	*	*	*
628	F<3 Timer Block	DDB_UFREQ_3_TIMER_BLOCK	PSL	PFSI	Block Under Frequency Stage 3 Timer	*	*	*	*
629	F<4 Timer Block	DDB_UFREQ_4_TIMER_BLOCK	PSL	PFSI	Block Under Frequency Stage 4 Timer	*	*	*	*
630	F>1 Timer Block	DDB_OFREQ_1_TIMER_BLOCK	PSL	PFSI	Block Over Frequency Stage 1 Timer	*	*	*	*
631	F>2 Timer Block	DDB_OFREQ_2_TIMER_BLOCK	PSL	PFSI	Block Over Frequency Stage 2 Timer	*	*	*	*
632	Turbine F Inh	DDB_TAF1_INHIBIT	PSL	PFSI	Inhibit Turbine Abnormal Frequency Protection	*	*	*	*
633	df/dt> Inhibit	DDB_DFDT_INHIBIT	PSL	PFSI	df/dt> Inhibit	*	*	*	*
634	df/dt>1 Tmr Blk	DDB_DFDT_1_TIMER_BLOCK	PSL	PFSI	df/dt>1 Tmr Blk	*	*	*	*
635	df/dt>2 Tmr Blk	DDB_DFDT_2_TIMER_BLOCK	PSL	PFSI	df/dt>2 Tmr Blk	*	*	*	*
636	df/dt>3 Tmr Blk	DDB_DFDT_3_TIMER_BLOCK	PSL	PFSI	df/dt>3 Tmr Blk	*	*	*	*
637	df/dt>4 Tmr Blk	DDB_DFDT_4_TIMER_BLOCK	PSL	PFSI	df/dt>4 Tmr Blk	*	*	*	*
638	Logic 0 Ref.	DDB_LOGIC_0	SW	PFSO	Logic 0 for use in PSL (Never changes state!)	*	*	*	*
639	DST status	DDB_DST_STATUS	SW	HIDDEN	If this location DST is in effect now	*	*	*	*
640	Reset I2 Thermal	DDB_RESET_NPS_THERMAL	PSL	PFSI	Reset NPS Thermal State	*	*	*	*
641	Reset GenThermal	DDB_RESET_GEN_THERMAL	PSL	PFSI	Reset Thermal Overload State	*	*	*	*
642	DLR I>1 Inhibit	DDB_DLR_AMP_TRIP_1_INHIBIT	PSL	PFSI	Inhibit DLR Stage 1				
643	DLR I>2 Inhibit	DDB_DLR_AMP_TRIP_2_INHIBIT	PSL	PFSI	Inhibit DLR Stage 2				
644	DLR I>3 Inhibit	DDB_DLR_AMP_TRIP_3_INHIBIT	PSL	PFSI	Inhibit DLR Stage 3				
645	DLR I>4 Inhibit	DDB_DLR_AMP_TRIP_4_INHIBIT	PSL	PFSI	Inhibit DLR Stage 4				
646	DLR I>5 Inhibit	DDB_DLR_AMP_TRIP_5_INHIBIT	PSL	PFSI	Inhibit DLR Stage 5				
647	DLR I>6 Inhibit	DDB_DLR_AMP_TRIP_6_INHIBIT	PSL	PFSI	Inhibit DLR Stage 6				
648	DLR Scheme Inh	DDB_DLR_SCHEME_INHIBIT	PSL	PFSI	Scheme Logic Inhibit				
649	Reset XThermal	DDB_RESET_XTHERMAL	PSL	PFSI	Reset Xformer Thermal Overload State	*	*	*	*
650	Forced Air Cool	DDB_XTHERMAL_AIRCOOL	PSL	PFSI	Select forced air cooling	*	*	*	*
651	Forced Oil Cool	DDB_XTHERMAL_OILCOOL	PSL	PFSI	Select forced oil cooling	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
652	TFR De-energised	DDB_TFR_DE_ENERGISED	PSL	PFSI	Xformer De-energised Status	*	*	*	*
653		DDB_UNUSED	SW	UNUSED					
654		DDB_UNUSED	SW	UNUSED					
655		DDB_UNUSED	SW	UNUSED					
656	CL Input 1 Blk	DDB_CL_INPUT_1_BLOCK	PSL	PFSI	Block Current Loop Input 1 protection	*	*	*	*
657	CL Input 2 Blk	DDB_CL_INPUT_2_BLOCK	PSL	PFSI	Block Current Loop Input 2 protection	*	*	*	*
658	CL Input 3 Blk	DDB_CL_INPUT_3_BLOCK	PSL	PFSI	Block Current Loop Input 3 protection	*	*	*	*
659	CL Input 4 Blk	DDB_CL_INPUT_4_BLOCK	PSL	PFSI	Block Current Loop Input 4 protection	*	*	*	*
660		DDB_UNUSED	SW	UNUSED					
661		DDB_UNUSED	SW	UNUSED					
662		DDB_UNUSED	SW	UNUSED					
663		DDB_UNUSED	SW	UNUSED					
664		DDB_UNUSED	SW	UNUSED					
665		DDB_UNUSED	SW	UNUSED					
666		DDB_UNUSED	SW	UNUSED					
667		DDB_UNUSED	SW	UNUSED					
668		DDB_UNUSED	SW	UNUSED					
669		DDB_UNUSED	SW	UNUSED					
670		DDB_UNUSED	SW	UNUSED					
671		DDB_UNUSED	SW	UNUSED					
672	Fault REC TRIG	DDB_FAULT_RECORDER_START	PSL	FRT	Fault Record Trigger Input	*	*	*	*
673		DDB_UNUSED	SW	UNUSED					
674	Any Trip	DDB_ANY_TRIP	PSL	PFSI	Any Trip	*	*	*	*
675	SG Select x1	DDB_SG_SELECTOR_X1	PSL	PFSI	Setting Group Selector x1 (bit 0)	*	*	*	*
676	SG Select 1x	DDB_SG_SELECTOR_1X	PSL	PFSI	Setting Group Selector 1x (bit 1)	*	*	*	*
677	Test Mode	DDB_TEST_MODE	PSL	PFSI	Initiate Test Mode	*	*	*	*
678	Init Trip CB	DDB_LOGIC_INPUT_TRIP	PSL	PFSI	Logic Input Trip CB	*	*	*	*
679	Init Close CB	DDB_LOGIC_INPUT_CLOSE	PSL	PFSI	Logic Input Close CB	*	*	*	*
680	Ext. Trip 3ph	DDB_EXTERNAL_TRIP_3PH	PSL	PFSI	External Trip 3ph	*	*	*	*
681	CB Aux 3ph(52-A)	DDB_CB_THREE_PHASE_52A	PSL	PFSI	52-A (3 phase)	*	*	*	*
682	CB Aux 3ph(52-B)	DDB_CB_THREE_PHASE_52B	PSL	PFSI	52-B (3 phase)	*	*	*	*
683	CB Healthy	DDB_CB_HEALTHY	PSL	PFSI	CB Healthy	*	*	*	*
684	MCB/VTS	DDB_VTS_MCB_OPTO	PSL	PFSI	MCB/VTS opto	*	*	*	*
685	Monitor Blocked	DDB_CS103_BLOCK	PSL	PFSI	IEC60870-5-103 Monitor Blocking	*	*	*	*
686	Command Blocked	DDB_CS103_CMD_BLOCK	PSL	PFSI	IEC60870-5-103 Command Blocking	*	*	*	*
687	Time Synch	DDB_TIME_SYNCH	PSL	PFSI	Time synchronise to nearest minute on 0-1 change	*	*	*	*
688	Reset Close Dly	DDB_RESET_CB_CLOSE_DELAY	PSL	PFSI	Reset Manual CB Close Time Delay	*	*	*	*
689	Reset Relays/LED	DDB_RESET_RELAYS_LEDS	PSL	PFSI	Reset Latched Relays & LED's	*	*	*	*
690	Reset Lockout	DDB_RESET_LOCKOUT	PSL	PFSI	Reset Lockout Opto Input	*	*	*	*
691	Reset All Values	DDB_RESET_ALL_VALUES	PSL	PFSI	Reset CB Maintenance Values	*	*	*	*
692	RP1 Read Only	DDB_RP1_READ_ONLY	PSL	PFSI	Remote Read Only 1 DDB	*	*	*	*
693	RP2 Read Only	DDB_RP2_READ_ONLY	PSL	PFSI	Remote Read Only 2 DDB	*	*	*	*
694	NIC Read Only	DDB_NIC_READ_ONLY	PSL	PFSI	Remote Read Only NIC DDB	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
695	103 MonitorBlock	DDB_MONITOR_BLOCKING	PSL	PFSI	Monitor Block	*	*	*	*
696	103 CommandBlock	DDB_COMMAND_BLOCKING	PSL	PFSI	Command Block	*	*	*	*
697	Not Used 6	DDB_DFDT_TRIP	SW	PFSO	In the previous version, these DDBs are exist and have related DNP3 address number.However in 36 version these DDBs are not used. If these DDBs are removed in 36 version, then most of the address numbers in 'DNP3 Object01' will be changed.	*	*	*	*
698	Not Used 7	DDB_DFDT_START	SW	PFSO		*	*	*	*
699		DDB_UNUSED	SW	UNUSED					
700		DDB_UNUSED	SW	UNUSED					
701		DDB_UNUSED	SW	UNUSED	So in order to keep the communication application of version 36 compatible with the previous version,				
702		DDB_UNUSED	SW	UNUSED					
703		DDB_UNUSED	SW	UNUSED					
704	SR User Alarm 1	DDB_USER_ALARM_1	PSL	PFSI	User definable Self Reset Alarm 1	*	*	*	*
705	SR User Alarm 2	DDB_USER_ALARM_2	PSL	PFSI	User definable Self Reset Alarm 2	*	*	*	*
706	SR User Alarm 3	DDB_USER_ALARM_3	PSL	PFSI	User definable Self Reset Alarm 3	*	*	*	*
707	SR User Alarm 4	DDB_USER_ALARM_4	PSL	PFSI	User definable Self Reset Alarm 4	*	*	*	*
708	SR User Alarm 5	DDB_USER_ALARM_5	PSL	PFSI	User definable Self Reset Alarm 5	*	*	*	*
709	SR User Alarm 6	DDB_USER_ALARM_6	PSL	PFSI	User definable Self Reset Alarm 6	*	*	*	*
710	SR User Alarm 7	DDB_USER_ALARM_7	PSL	PFSI	User definable Self Reset Alarm 7	*	*	*	*
711	SR User Alarm 8	DDB_USER_ALARM_8	PSL	PFSI	User definable Self Reset Alarm 8	*	*	*	*
712	SR User Alarm 9	DDB_USER_ALARM_9	PSL	PFSI	User definable Self Reset Alarm 9	*	*	*	*
713	SR User Alarm 10	DDB_USER_ALARM_10	PSL	PFSI	User definable Self Reset Alarm 10	*	*	*	*
714	SR User Alarm 11	DDB_USER_ALARM_11	PSL	PFSI	User definable Self Reset Alarm 11	*	*	*	*
715	SR User Alarm 12	DDB_USER_ALARM_12	PSL	PFSI	User definable Self Reset Alarm 12	*	*	*	*
716	SR User Alarm 13	DDB_USER_ALARM_13	PSL	PFSI	User definable Self Reset Alarm 13	*	*	*	*
717	SR User Alarm 14	DDB_USER_ALARM_14	PSL	PFSI	User definable Self Reset Alarm 14	*	*	*	*
718	SR User Alarm 15	DDB_USER_ALARM_15	PSL	PFSI	User definable Self Reset Alarm 15	*	*	*	*
719	SR User Alarm 16	DDB_USER_ALARM_16	PSL	PFSI	User definable Self Reset Alarm 16	*	*	*	*
720	MR User Alarm 17	DDB_USER_ALARM_17	PSL	PFSI	User definable Manual Reset Alarm 17	*	*	*	*
721	MR User Alarm 18	DDB_USER_ALARM_18	PSL	PFSI	User definable Manual Reset Alarm 18	*	*	*	*
722	MR User Alarm 19	DDB_USER_ALARM_19	PSL	PFSI	User definable Manual Reset Alarm 19	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
723	MR User Alarm 20	DDB_USER_ALARM_20	PSL	PFSI	User definable Manual Reset Alarm 20	*	*	*	*
724	MR User Alarm 21	DDB_USER_ALARM_21	PSL	PFSI	User definable Manual Reset Alarm 21	*	*	*	*
725	MR User Alarm 22	DDB_USER_ALARM_22	PSL	PFSI	User definable Manual Reset Alarm 22	*	*	*	*
726	MR User Alarm 23	DDB_USER_ALARM_23	PSL	PFSI	User definable Manual Reset Alarm 23	*	*	*	*
727	MR User Alarm 24	DDB_USER_ALARM_24	PSL	PFSI	User definable Manual Reset Alarm 24	*	*	*	*
728	MR User Alarm 25	DDB_USER_ALARM_25	PSL	PFSI	User definable Manual Reset Alarm 25	*	*	*	*
729	MR User Alarm 26	DDB_USER_ALARM_26	PSL	PFSI	User definable Manual Reset Alarm 26	*	*	*	*
730	MR User Alarm 27	DDB_USER_ALARM_27	PSL	PFSI	User definable Manual Reset Alarm 27	*	*	*	*
731	MR User Alarm 28	DDB_USER_ALARM_28	PSL	PFSI	User definable Manual Reset Alarm 28	*	*	*	*
732	MR User Alarm 29	DDB_USER_ALARM_29	PSL	PFSI	User definable Manual Reset Alarm 29	*	*	*	*
733	MR User Alarm 30	DDB_USER_ALARM_30	PSL	PFSI	User definable Manual Reset Alarm 30	*	*	*	*
734	MR User Alarm 31	DDB_USER_ALARM_31	PSL	PFSI	User definable Manual Reset Alarm 31	*	*	*	*
735	MR User Alarm 32	DDB_USER_ALARM_32	PSL	PFSI	User definable Manual Reset Alarm 32	*	*	*	*
736	Gen Diff Trip	DDB_GENDIFF_3PH_TRIP	SW	PFSO	Generator Differential Trip 3ph		*	*	*
737	Gen Diff Trip A	DDB_GENDIFF_PH_A_TRIP	SW	PFSO	Generator Differential Trip A		*	*	*
738	Gen Diff Trip B	DDB_GENDIFF_PH_B_TRIP	SW	PFSO	Generator Differential Trip B		*	*	*
739	Gen Diff Trip C	DDB_GENDIFF_PH_C_TRIP	SW	PFSO	Generator Differential Trip C		*	*	*
740	Xform Dif Trp	DDB_XFORMER_DIFF_3PH_TRIP	SW	PFSO	Xformer Differential Trip 3ph		*	*	*
741	Xform Dif Trip A	DDB_XFORMER_DIFF_PH_A_TRIP	SW	PFSO	Xformer Differential Trip A		*	*	*
742	Xform Dif Trip B	DDB_XFORMER_DIFF_PH_B_TRIP	SW	PFSO	Xformer Differential Trip B		*	*	*
743	Xform Dif Trip C	DDB_XFORMER_DIFF_PH_C_TRIP	SW	PFSO	Xformer Differential Trip C		*	*	*
744	Xform Bias Trp A	DDB_XFORMER_DIFF_BIAS_TRIP_A	SW	PFSO	Xformer Differential Low Set Trip A		*	*	*
745	Xform Bias Trp B	DDB_XFORMER_DIFF_BIAS_TRIP_B	SW	PFSO	Xformer Differential Low Set Trip B		*	*	*
746	Xform Bias Trp C	DDB_XFORMER_DIFF_BIAS_TRIP_C	SW	PFSO	Xformer Differential Low Set Trip C		*	*	*
747	Xform HS1 Trip A	DDB_XFORMER_DIFF_HS1_TRIP_A	SW	PFSO	Xformer Differential HS1 Trip A		*	*	*
748	Xform HS1 Trip B	DDB_XFORMER_DIFF_HS1_TRIP_B	SW	PFSO	Xformer Differential HS1Trip B		*	*	*
749	Xform HS1 Trip C	DDB_XFORMER_DIFF_HS1_TRIP_C	SW	PFSO	Xformer Differential HS1Trip C		*	*	*
750	Xform HS2 Trip A	DDB_XFORMER_DIFF_HS2_TRIP_A	SW	PFSO	Xformer Differential HS2 Trip A		*	*	*
751	Xform HS2 Trip B	DDB_XFORMER_DIFF_HS2_TRIP_B	SW	PFSO	Xformer Differential HS2Trip B		*	*	*
752	Xform HS2 Trip C	DDB_XFORMER_DIFF_HS2_TRIP_C	SW	PFSO	Xformer Differential HS2Trip C		*	*	*
753		DDB_UNUSED	SW	UNUSED					
754		DDB_UNUSED	SW	UNUSED					
755		DDB_UNUSED	SW	UNUSED					
756		DDB_UNUSED	SW	UNUSED					
757		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
758		DDB_UNUSED	SW	UNUSED					
759		DDB_UNUSED	SW	UNUSED					
760		DDB_UNUSED	SW	UNUSED					
761		DDB_UNUSED	SW	UNUSED					
762		DDB_UNUSED	SW	UNUSED					
763		DDB_UNUSED	SW	UNUSED					
764		DDB_UNUSED	SW	UNUSED					
765		DDB_UNUSED	SW	UNUSED					
766		DDB_UNUSED	SW	UNUSED					
767		DDB_UNUSED	SW	UNUSED					
768	IN>1 Trip	DDB_EF1_1_TRIP	SW	PFSO	1st Stage EF Trip	*	*	*	*
769	IN>2 Trip	DDB_EF1_2_TRIP	SW	PFSO	2nd Stage EF Trip	*	*	*	*
770	IN>3 Trip	DDB_EF1_3_TRIP	SW	PFSO	3rd Stage EF Trip				
771	IN>4 Trip	DDB_EF1_4_TRIP	SW	PFSO	4th Stage EF Trip				
772	IREF> Trip	DDB_REF_TRIP	SW	PFSO	REF Trip	*	*	*	*
773	ISEF>1 Trip	DDB_SEF_1_TRIP	SW	PFSO	1st Stage SEF Trip	*	*	*	*
774	ISEF>2 Trip	DDB_SEF_2_TRIP	SW	PFSO	2nd Stage SEF Trip				
775	ISEF>3 Trip	DDB_SEF_3_TRIP	SW	PFSO	3rd Stage SEF Trip				
776	ISEF>4 Trip	DDB_SEF_4_TRIP	SW	PFSO	4th Stage SEF Trip				
777	100%StEF3H Trip	DDB_V3H_TRIP	SW	PFSO	100% Stator Earth Fault (3rd harmonic) Trip		*	*	*
778	64S I>1 Trip	DDB_STEFI_OC_1_TRIP	SW	PFSO	64S 100% Stator Earth Fault Overcurrent Trip				*
779	64S R<2 Trip	DDB_STEFI_UR_2_TRIP	SW	PFSO	64S 100% St EF Under Resistance Stage 2 Trip				*
780	64R R<2 Trip	DDB_64R_UR_2_TRIP	SW	PFSO	64R Rotor Earth Fault Under Resistance Stage 2 Trip	*	*	*	*
781		DDB_UNUSED	SW	UNUSED					
782		DDB_UNUSED	SW	UNUSED					
783		DDB_UNUSED	SW	UNUSED					
784		DDB_UNUSED	SW	UNUSED					
785		DDB_UNUSED	SW	UNUSED					
786		DDB_UNUSED	SW	UNUSED					
787		DDB_UNUSED	SW	UNUSED					
788		DDB_UNUSED	SW	UNUSED					
789		DDB_UNUSED	SW	UNUSED					
790		DDB_UNUSED	SW	UNUSED					
791		DDB_UNUSED	SW	UNUSED					
792		DDB_UNUSED	SW	UNUSED					
793		DDB_UNUSED	SW	UNUSED					
794		DDB_UNUSED	SW	UNUSED					
795		DDB_UNUSED	SW	UNUSED					
796		DDB_UNUSED	SW	UNUSED					
797		DDB_UNUSED	SW	UNUSED					
798		DDB_UNUSED	SW	UNUSED					
799		DDB_UNUSED	SW	UNUSED					
800	I>1 Trip	DDB_POC_1_3PH_TRIP	SW	PFSO	1st Stage O/C Trip 3ph	*	*	*	*
801	I>1 Trip A	DDB_POC_1_PH_A_TRIP	SW	PFSO	1st Stage O/C Trip A	*	*	*	*
802	I>1 Trip B	DDB_POC_1_PH_B_TRIP	SW	PFSO	1st Stage O/C Trip B	*	*	*	*
803	I>1 Trip C	DDB_POC_1_PH_C_TRIP	SW	PFSO	1st Stage O/C Trip C	*	*	*	*
804	I>2 Trip	DDB_POC_2_3PH_TRIP	SW	PFSO	2nd Stage O/C Trip 3ph	*	*	*	*
805	I>2 Trip A	DDB_POC_2_PH_A_TRIP	SW	PFSO	2nd Stage O/C Trip A	*	*	*	*
806	I>2 Trip B	DDB_POC_2_PH_B_TRIP	SW	PFSO	2nd Stage O/C Trip B	*	*	*	*
807	I>2 Trip C	DDB_POC_2_PH_C_TRIP	SW	PFSO	2nd Stage O/C Trip C	*	*	*	*
808	I>3 Trip	DDB_POC_3_3PH_TRIP	SW	PFSO	3rd Stage O/C Trip 3ph	*	*	*	*
809	I>3 Trip A	DDB_POC_3_PH_A_TRIP	SW	PFSO	3rd Stage O/C Trip A	*	*	*	*
810	I>3 Trip B	DDB_POC_3_PH_B_TRIP	SW	PFSO	3rd Stage O/C Trip B	*	*	*	*
811	I>3 Trip C	DDB_POC_3_PH_C_TRIP	SW	PFSO	3rd Stage O/C Trip C	*	*	*	*
812	I>4 Trip	DDB_POC_4_3PH_TRIP	SW	PFSO	4th Stage O/C Trip 3ph	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
813	I>4 Trip A	DDB_POC_4_PH_A_TRIP	SW	PFSO	4th Stage O/C Trip A	*	*	*	*
814	I>4 Trip B	DDB_POC_4_PH_B_TRIP	SW	PFSO	4th Stage O/C Trip B	*	*	*	*
815	I>4 Trip C	DDB_POC_4_PH_C_TRIP	SW	PFSO	4th Stage O/C Trip C	*	*	*	*
816		DDB_UNUSED	SW	UNUSED					
817		DDB_UNUSED	SW	UNUSED					
818		DDB_UNUSED	SW	UNUSED					
819		DDB_UNUSED	SW	UNUSED					
820		DDB_UNUSED	SW	UNUSED					
821		DDB_UNUSED	SW	UNUSED					
822		DDB_UNUSED	SW	UNUSED					
823		DDB_UNUSED	SW	UNUSED					
824	I2>1 Trip	DDB_NPSOC_1_TRIP	SW	PFSO	NPS Overcurrent Stage 1 Trip	*	*	*	*
825	I2>2 Trip	DDB_NPSOC_2_TRIP	SW	PFSO	NPS Overcurrent Stage 2 Trip	*	*	*	*
826	I2>3 Trip	DDB_NPSOC_3_TRIP	SW	PFSO	NPS Overcurrent Stage 3 Trip	*	*	*	*
827	I2>4 Trip	DDB_NPSOC_4_TRIP	SW	PFSO	NPS Overcurrent Stage 4 Trip	*	*	*	*
828	Bfail1 Trip 3ph	DDB_CBF1_TRIP_3PH	SW	PFSO	tBF1 Trip 3ph	*	*	*	*
829	Bfail2 Trip 3ph	DDB_CBF2_TRIP_3PH	SW	PFSO	tBF2 Trip 3ph	*	*	*	*
830		DDB_UNUSED	SW	UNUSED					
831		DDB_UNUSED	SW	UNUSED					
832	VN>1 Trip	DDB_RESOV_1_TRIP	SW	PFSO	1st Stage Residual O/V Trip	*	*	*	*
833	VN>2 Trip	DDB_RESOV_2_TRIP	SW	PFSO	2nd Stage Residual O/V Trip	*	*	*	*
834	VN>3 Trip	DDB_RESOV_3_TRIP	SW	PFSO	Residual O/V Stage 3 Trip	*	*	*	*
835	VN>4 Trip	DDB_RESOV_4_TRIP	SW	PFSO	Residual O/V Stage 4 Trip	*	*	*	*
836	VN>5 Trip	DDB_RESOV_5_TRIP	SW	PFSO	Residual O/V Stage 5 Trip			*	*
837	VN>6 Trip	DDB_RESOV_6_TRIP	SW	PFSO	Residual O/V Stage 6 Trip			*	*
838	V>1 Trip	DDB_POV_1_3PH_TRIP	SW	PFSO	1st Stage Phase O/V Trip 3ph	*	*	*	*
839	V>1 Trip A/AB	DDB_POV_1_PH_A_TRIP	SW	PFSO	1st Stage Phase O/V Trip A/AB	*	*	*	*
840	V>1 Trip B/BC	DDB_POV_1_PH_B_TRIP	SW	PFSO	1st Stage Phase O/V Trip B/BC	*	*	*	*
841	V>1 Trip C/CA	DDB_POV_1_PH_C_TRIP	SW	PFSO	1st Stage Phase O/V Trip C/CA	*	*	*	*
842	V>2 Trip	DDB_POV_2_3PH_TRIP	SW	PFSO	2nd Stage Phase O/V Trip 3ph	*	*	*	*
843	V>2 Trip A/AB	DDB_POV_2_PH_A_TRIP	SW	PFSO	2nd Stage Phase O/V Trip A/AB	*	*	*	*
844	V>2 Trip B/BC	DDB_POV_2_PH_B_TRIP	SW	PFSO	2nd Stage Phase O/V Trip B/BC	*	*	*	*
845	V>2 Trip C/CA	DDB_POV_2_PH_C_TRIP	SW	PFSO	2nd Stage Phase O/V Trip C/CA	*	*	*	*
846	V2>1 Trip	DDB_NPSOV_1_TRIP	SW	PFSO	NPS Over Voltage Stage 1 Trip	*	*	*	*
847	V<1 Trip	DDB_PUV_1_3PH_TRIP	SW	PFSO	1st Stage Phase U/V Trip 3ph	*	*	*	*
848	V<1 Trip A/AB	DDB_PUV_1_PH_A_TRIP	SW	PFSO	1st Stage Phase U/V Trip A/AB	*	*	*	*
849	V<1 Trip B/BC	DDB_PUV_1_PH_B_TRIP	SW	PFSO	1st Stage Phase U/V Trip B/BC	*	*	*	*
850	V<1 Trip C/CA	DDB_PUV_1_PH_C_TRIP	SW	PFSO	1st Stage Phase U/V Trip C/CA	*	*	*	*
851	V<2 Trip	DDB_PUV_2_3PH_TRIP	SW	PFSO	2nd Stage Phase U/V Trip 3ph	*	*	*	*
852	V<2 Trip A/AB	DDB_PUV_2_PH_A_TRIP	SW	PFSO	2nd Stage Phase U/V Trip A/AB	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
853	V<2 Trip B/BC	DDB_PUV_2_PH_B_TRIP	SW	PFSO	2nd Stage Phase U/V Trip B/BC	*	*	*	*
854	V<2 Trip C/CA	DDB_PUV_2_PH_C_TRIP	SW	PFSO	2nd Stage Phase U/V Trip C/CA	*	*	*	*
855		DDB_UNUSED	SW	UNUSED					
856		DDB_UNUSED	SW	UNUSED					
857		DDB_UNUSED	SW	UNUSED					
858		DDB_UNUSED	SW	UNUSED					
859		DDB_UNUSED	SW	UNUSED					
860		DDB_UNUSED	SW	UNUSED					
861		DDB_UNUSED	SW	UNUSED					
862		DDB_UNUSED	SW	UNUSED					
863		DDB_UNUSED	SW	UNUSED					
864	Field Fail1 Trip	DDB_FIELDF_1_TRIP	SW	PFSO	Field Failure Stage 1 Trip	*	*	*	*
865	Field Fail2 Trip	DDB_FIELDF_2_TRIP	SW	PFSO	Field Failure Stage 2 Trip	*	*	*	*
866	PSlipz Z1 Trip	DDB_POLESLZ_ZONE1_TRIP	SW	PFSO	Pole Slip (Impedance) Zone1 Trip		*	*	*
867	PSlipz Z2 Trip	DDB_POLESLZ_ZONE2_TRIP	SW	PFSO	Pole Slip (Impedance) Zone2 Trip		*	*	*
868	V Dep OC Trip	DDB_VOLT_DEP_OC_3PH_TRIP	SW	PFSO	Voltage Dependant Overcurrent Trip 3ph	*	*	*	*
869	V Dep OC Trip A	DDB_VOLT_DEP_OC_PH_A_TRIP	SW	PFSO	Voltage Dependant Overcurrent Trip A	*	*	*	*
870	V Dep OC Trip B	DDB_VOLT_DEP_OC_PH_B_TRIP	SW	PFSO	Voltage Dependant Overcurrent Trip B	*	*	*	*
871	V Dep OC Trip C	DDB_VOLT_DEP_OC_PH_C_TRIP	SW	PFSO	Voltage Dependant Overcurrent Trip C	*	*	*	*
872	Z<1 Trip	DDB_UNDERZ_1_3PH_TRIP	SW	PFSO	Under Impedance 3Phase Stage 1 Trip	*	*	*	*
873	Z<1 Trip A	DDB_UNDERZ_1_PH_A_TRIP	SW	PFSO	Under Impedance Phase A Stage 1 Trip	*	*	*	*
874	Z<1 Trip B	DDB_UNDERZ_1_PH_B_TRIP	SW	PFSO	Under Impedance Phase B Stage 1 Trip	*	*	*	*
875	Z<1 Trip C	DDB_UNDERZ_1_PH_C_TRIP	SW	PFSO	Under Impedance Phase C Stage 1 Trip	*	*	*	*
876	Z<2 Trip	DDB_UNDERZ_2_3PH_TRIP	SW	PFSO	Under Impedance 3Phase Stage 2 Trip	*	*	*	*
877	Z<2 Trip A	DDB_UNDERZ_2_PH_A_TRIP	SW	PFSO	Under Impedance Phase A Stage 2 Trip	*	*	*	*
878	Z<2 Trip B	DDB_UNDERZ_2_PH_B_TRIP	SW	PFSO	Under Impedance Phase B Stage 2 Trip	*	*	*	*
879	Z<2 Trip C	DDB_UNDERZ_2_PH_C_TRIP	SW	PFSO	Under Impedance Phase C Stage 2 Trip	*	*	*	*
880	DeadMachine Trip	DDB_DEADMACH_TRIP	SW	PFSO	Dead Machine Protection Trip		*	*	*
881	S2>1 Trip	DDB_PWRNPS_1_TRIP	SW	PFSO	NPS Overpower Stage 1 trip	*	*	*	*
882	Power1 Trip	DDB_POWER_1_TRIP	SW	PFSO	Power Stage 1 Trip	*	*	*	*
883	Power2 Trip	DDB_POWER_2_TRIP	SW	PFSO	Power Stage 2 Trip	*	*	*	*
884	SPower1 Trip	DDB_SPOWER_1_TRIP	SW	PFSO	Sensitive A Phase Power Stage 1 Trip	*	*	*	*
885	SPower2 Trip	DDB_SPOWER_2_TRIP	SW	PFSO	Sensitive A Phase Power Stage 2 Trip	*	*	*	*
886		DDB_UNUSED	SW	UNUSED					
887		DDB_UNUSED	SW	UNUSED					
888		DDB_UNUSED	SW	UNUSED					
889		DDB_UNUSED	SW	UNUSED					
890		DDB_UNUSED	SW	UNUSED					
891		DDB_UNUSED	SW	UNUSED					
892		DDB_UNUSED	SW	UNUSED					
893		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
894		DDB_UNUSED	SW	UNUSED					
895		DDB_UNUSED	SW	UNUSED					
896		DDB_UNUSED	SW	UNUSED					
897		DDB_UNUSED	SW	UNUSED					
898		DDB_UNUSED	SW	UNUSED					
899		DDB_UNUSED	SW	UNUSED					
900		DDB_UNUSED	SW	UNUSED					
901		DDB_UNUSED	SW	UNUSED					
902		DDB_UNUSED	SW	UNUSED					
903		DDB_UNUSED	SW	UNUSED					
904		DDB_UNUSED	SW	UNUSED					
905		DDB_UNUSED	SW	UNUSED					
906		DDB_UNUSED	SW	UNUSED					
907		DDB_UNUSED	SW	UNUSED					
908		DDB_UNUSED	SW	UNUSED					
909		DDB_UNUSED	SW	UNUSED					
910		DDB_UNUSED	SW	UNUSED					
911		DDB_UNUSED	SW	UNUSED					
912	V/Hz>1 Trip	DDB_VPERHZ_TRIP	SW	PFSO	1st Stage Volts per Hz Trip	*	*	*	*
913	V/Hz>2 Trip	DDB_VPERHZ_TRIP2	SW	PFSO	Volts per Hz Stage 2 Trip	*	*	*	*
914	V/Hz>3 Trip	DDB_VPERHZ_TRIP3	SW	PFSO	Volts per Hz Stage 3 Trip	*	*	*	*
915	V/Hz>4 Trip	DDB_VPERHZ_TRIP4	SW	PFSO	Volts per Hz Stage 4 Trip	*	*	*	*
916	F<1 Trip	DDB_UFREQ_1_TRIP	SW	PFSO	Under Frequency Stage 1 Trip	*	*	*	*
917	F<2 Trip	DDB_UFREQ_2_TRIP	SW	PFSO	Under Frequency Stage 2 Trip	*	*	*	*
918	F<3 Trip	DDB_UFREQ_3_TRIP	SW	PFSO	Under Frequency Stage 3 Trip	*	*	*	*
919	F<4 Trip	DDB_UFREQ_4_TRIP	SW	PFSO	Under Frequency Stage 4 Trip	*	*	*	*
920	F>1 Trip	DDB_OFREQ_1_TRIP	SW	PFSO	Over Frequency Stage 1 Trip	*	*	*	*
921	F>2 Trip	DDB_OFREQ_2_TRIP	SW	PFSO	Over Frequency Stage 2 Trip	*	*	*	*
922	Freq Band1 Trip	DDB_TAF1_TRIP1	SW	PFSO	Turbine Abnormal Frequency Band 1 Trip	*	*	*	*
923	Freq Band2 Trip	DDB_TAF1_TRIP2	SW	PFSO	Turbine Abnormal Frequency Band 2 Trip	*	*	*	*
924	Freq Band3 Trip	DDB_TAF1_TRIP3	SW	PFSO	Turbine Abnormal Frequency Band 3 Trip	*	*	*	*
925	Freq Band4 Trip	DDB_TAF1_TRIP4	SW	PFSO	Turbine Abnormal Frequency Band 4 Trip	*	*	*	*
926	Freq Band5 Trip	DDB_TAF1_TRIP5	SW	PFSO	Turbine Abnormal Frequency Band 5 Trip	*	*	*	*
927	Freq Band6 Trip	DDB_TAF1_TRIP6	SW	PFSO	Turbine Abnormal Frequency Band 6 Trip	*	*	*	*
928	df/dt>1 Trip	DDB_DFDT_1_TRIP	SW	PFSO	df/dt>1 Trip	*	*	*	*
929	df/dt>2 Trip	DDB_DFDT_2_TRIP	SW	PFSO	df/dt>2 Trip	*	*	*	*
930	df/dt>3 Trip	DDB_DFDT_3_TRIP	SW	PFSO	df/dt>3 Trip	*	*	*	*
931	df/dt>4 Trip	DDB_DFDT_4_TRIP	SW	PFSO	df/dt>4 Trip	*	*	*	*
932		DDB_UNUSED	SW	UNUSED					
933	V Shift Trip	DDB_VSHIFT_TRIP	SW	PFSO	Voltage Vector Shift Trip				
934		DDB_UNUSED	SW	UNUSED					
935		DDB_UNUSED	SW	UNUSED					
936	df/dt>1 Under F	DDB_DFDT_1_UF	SW	PFSO	Rate Of Change Of Frequency Stage 1 Under Frequency	*	*	*	*
937	df/dt>1 Over F	DDB_DFDT_1_OF	SW	PFSO	Rate Of Change Of Frequency Stage 1 Over Frequency	*	*	*	*
938	Logged into UI	DDB_UI_LOGGEDIN	SW	PFSO	User logged into UI	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
939	Logged into FP	DDB_FCUR_LOGGEDIN	SW	PFSO	User logged into front port courier	*	*	*	*
940	Logged into RP1	DDB_RP1_LOGGEDIN	SW	PFSO	User logged into Rear Port1 courier	*	*	*	*
941	Logged into RP2	DDB_RP2_LOGGEDIN	SW	PFSO	User logged into Rear Port2 courier	*	*	*	*
942	Logged into TNL	DDB_TNL_LOGGEDIN	SW	PFSO	User logged into turnneled courier	*	*	*	*
943	Logged into CPR	DDB_CPR_LOGGEDIN	SW	PFSO	User logged into co-processor courier	*	*	*	*
944	NPS Thermal Trip	DDB_NPS_TRIP	SW	PFSO	Negative Phase Sequence Thermal Trip	*	*	*	*
945	Gen Thermal Trip	DDB_GEN_THERMAL_TRIP	SW	PFSO	Thermal Overload Trip	*	*	*	*
946	Hot Spot>1 Trip	DDB_XFORMER_HOT_SPOT_1_TRIP	SW	PFSO	Hot Spot>1 Trip	*	*	*	*
947	Hot Spot>2 Trip	DDB_XFORMER_HOT_SPOT_2_TRIP	SW	PFSO	Hot Spot>2 Trip	*	*	*	*
948	Hot Spot>3 Trip	DDB_XFORMER_HOT_SPOT_3_TRIP	SW	PFSO	Hot Spot>3 Trip	*	*	*	*
949	Top Oil>1 Trip	DDB_XFORMER_TOP_OIL_1_TRIP	SW	PFSO	Top Oil>1 Trip	*	*	*	*
950	Top Oil>2 Trip	DDB_XFORMER_TOP_OIL_2_TRIP	SW	PFSO	Top Oil>2 Trip	*	*	*	*
951	Top Oil>3 Trip	DDB_XFORMER_TOP_OIL_3_TRIP	SW	PFSO	Top Oil>3 Trip	*	*	*	*
952	DLR I>1 Trip	DDB_DLR_AMP_1_TRIP	SW	PFSO	DLR Ampacity prot. stage 1 trip				
953	DLR I>2 Trip	DDB_DLR_AMP_2_TRIP	SW	PFSO	DLR Ampacity prot. stage 2 trip				
954	DLR I>3 Trip	DDB_DLR_AMP_3_TRIP	SW	PFSO	DLR Ampacity prot. stage 3 trip				
955	DLR I>4 Trip	DDB_DLR_AMP_4_TRIP	SW	PFSO	DLR Ampacity prot. stage 4 trip				
956	DLR I>5 Trip	DDB_DLR_AMP_5_TRIP	SW	PFSO	DLR Ampacity prot. stage 5 trip				
957	DLR I>6 Trip	DDB_DLR_AMP_6_TRIP	SW	PFSO	DLR Ampacity prot. stage 6 trip				
958		DDB_UNUSED	SW	UNUSED					
959		DDB_UNUSED	SW	UNUSED					
960		DDB_UNUSED	SW	UNUSED					
961		DDB_UNUSED	SW	UNUSED					
962		DDB_UNUSED	SW	UNUSED					
963		DDB_UNUSED	SW	UNUSED					
964		DDB_UNUSED	SW	UNUSED					
965		DDB_UNUSED	SW	UNUSED					
966		DDB_UNUSED	SW	UNUSED					
967		DDB_UNUSED	SW	UNUSED					
968		DDB_UNUSED	SW	UNUSED					
969		DDB_UNUSED	SW	UNUSED					
970		DDB_UNUSED	SW	UNUSED					
971		DDB_UNUSED	SW	UNUSED					
972		DDB_UNUSED	SW	UNUSED					
973		DDB_UNUSED	SW	UNUSED					
974		DDB_UNUSED	SW	UNUSED					
975		DDB_UNUSED	SW	UNUSED					
976	RTD 1 Trip	DDB_RTD_1_TRIP	SW	PFSO	RTD 1 Trip	*	*	*	*
977	RTD 2 Trip	DDB_RTD_2_TRIP	SW	PFSO	RTD 2 Trip	*	*	*	*
978	RTD 3 Trip	DDB_RTD_3_TRIP	SW	PFSO	RTD 3 Trip	*	*	*	*
979	RTD 4 Trip	DDB_RTD_4_TRIP	SW	PFSO	RTD 4 Trip	*	*	*	*
980	RTD 5 Trip	DDB_RTD_5_TRIP	SW	PFSO	RTD 5 Trip	*	*	*	*
981	RTD 6 Trip	DDB_RTD_6_TRIP	SW	PFSO	RTD 6 Trip	*	*	*	*
982	RTD 7 Trip	DDB_RTD_7_TRIP	SW	PFSO	RTD 7 Trip	*	*	*	*
983	RTD 8 Trip	DDB_RTD_8_TRIP	SW	PFSO	RTD 8 Trip	*	*	*	*
984	RTD 9 Trip	DDB_RTD_9_TRIP	SW	PFSO	RTD 9 Trip	*	*	*	*
985	RTD 10 Trip	DDB_RTD_10_TRIP	SW	PFSO	RTD 10 Trip	*	*	*	*
986	Any RTD Trip	DDB_ANY_RTD_TRIP	FL	PFSO	Any RTD Trip	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
987	CL Input 1 Trip	DDB_CL_INPUT_1_TRIP	SW	PFSO	Current Loop Input 1 Trip	*	*	*	*
988	CL Input 2 Trip	DDB_CL_INPUT_2_TRIP	SW	PFSO	Current Loop Input 2 Trip	*	*	*	*
989	CL Input 3 Trip	DDB_CL_INPUT_3_TRIP	SW	PFSO	Current Loop Input 3 Trip	*	*	*	*
990	CL Input 4 Trip	DDB_CL_INPUT_4_TRIP	SW	PFSO	Current Loop Input 4 Trip	*	*	*	*
991	Unused	DDB_UNUSED_DR	SW	UNUSED	Provides the "Unused" selection in G32	*	*	*	*
992	Any Start	DDB_ANY_START	FL	PFSO	Any Start	*	*	*	*
993	Xform Bias StrtA	DDB_XFORMER_DIFF_BIAS_STARTA	SW	PFSO	Xformer Differential Start A		*	*	*
994	Xform Bias StrtB	DDB_XFORMER_DIFF_BIAS_STARTB	SW	PFSO	Xformer Differential Start B		*	*	*
995	Xform Bias StrtC	DDB_XFORMER_DIFF_BIAS_STARTC	SW	PFSO	Xformer Differential Start C		*	*	*
996		DDB_UNUSED	SW	UNUSED					
997		DDB_UNUSED	SW	UNUSED					
998		DDB_UNUSED	SW	UNUSED					
999		DDB_UNUSED	SW	UNUSED					
1000		DDB_UNUSED	SW	UNUSED					
1001		DDB_UNUSED	SW	UNUSED					
1002		DDB_UNUSED	SW	UNUSED					
1003		DDB_UNUSED	SW	UNUSED					
1004		DDB_UNUSED	SW	UNUSED					
1005		DDB_UNUSED	SW	UNUSED					
1006		DDB_UNUSED	SW	UNUSED					
1007		DDB_UNUSED	SW	UNUSED					
1008	IN>1 Start	DDB_EF1_1_START	SW	PFSO	1st Stage EF Start	*	*	*	*
1009	IN>2 Start	DDB_EF1_2_START	SW	PFSO	2nd Stage EF Start	*	*	*	*
1010	IN>3 Start	DDB_EF1_3_START	SW	PFSO	3rd Stage EF Start				
1011	IN>4 Start	DDB_EF1_4_START	SW	PFSO	4th Stage EF Start				
1012	ISEF>1 Start	DDB_SEF_1_START	SW	PFSO	1st Stage SEF Start	*	*	*	*
1013	ISEF>2 Start	DDB_SEF_2_START	SW	PFSO	2nd Stage SEF Start				
1014	ISEF>3 Start	DDB_SEF_3_START	SW	PFSO	3rd Stage SEF Start				
1015	ISEF>4 Start	DDB_SEF_4_START	SW	PFSO	4th Stage SEF Start				
1016	100%StEF3H Start	DDB_V3H_START	SW	PFSO	100% Stator Earth Fault (3rd harmonic) Start		*	*	*
1017	64S I< Start	DDB_STEFI_FAIL_I_START	SW	PFSO	64S 100% Stator Earth Fault Undercurrent Start				*
1018	64S V< Start	DDB_STEFI_FAIL_V_START	SW	PFSO	64S 100% Stator Earth Fault Undervoltage Start				*
1019	64S I>1 Start	DDB_STEFI_OC_1_START	SW	PFSO	64S 100% Stator Earth Fault Overcurrent Start				*
1020	64S Start R<1Alm	DDB_STEFI_UR_1_START	SW	PFSO	64S 100% St EF Under Resistance Stg 1 Alm Start				*
1021	64S R<2 Start	DDB_STEFI_UR_2_START	SW	PFSO	64S 100% St EF Under Resistance Stg 2 Trip Start				*
1022	64R Start R<1Alm	DDB_64R_UR_1_START	SW	PFSO	64R Rotor EF Under Resistance Stg 1 Alm Start	*	*	*	*
1023	64R R<2 Start	DDB_64R_UR_2_START	SW	PFSO	64R Rotor EF Under Resistance Stg 2 Trip Start	*	*	*	*
1024		DDB_UNUSED	SW	UNUSED					
1025		DDB_UNUSED	SW	UNUSED					
1026		DDB_UNUSED	SW	UNUSED					
1027		DDB_UNUSED	SW	UNUSED					
1028		DDB_UNUSED	SW	UNUSED					
1029		DDB_UNUSED	SW	UNUSED					
1030		DDB_UNUSED	SW	UNUSED					
1031		DDB_UNUSED	SW	UNUSED					
1032		DDB_UNUSED	SW	UNUSED					
1033		DDB_UNUSED	SW	UNUSED					
1034		DDB_UNUSED	SW	UNUSED					
1035		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1036		DDB_UNUSED	SW	UNUSED					
1037		DDB_UNUSED	SW	UNUSED					
1038		DDB_UNUSED	SW	UNUSED					
1039		DDB_UNUSED	SW	UNUSED					
1040	I>1 Start	DDB_POC_1_3PH_START	SW	PFSO	1st Stage O/C Start 3ph	*	*	*	*
1041	I>1 Start A	DDB_POC_1_PH_A_START	SW	PFSO	1st Stage O/C Start A	*	*	*	*
1042	I>1 Start B	DDB_POC_1_PH_B_START	SW	PFSO	1st Stage O/C Start B	*	*	*	*
1043	I>1 Start C	DDB_POC_1_PH_C_START	SW	PFSO	1st Stage O/C Start C	*	*	*	*
1044	I>2 Start	DDB_POC_2_3PH_START	SW	PFSO	2nd Stage O/C Start 3ph	*	*	*	*
1045	I>2 Start A	DDB_POC_2_PH_A_START	SW	PFSO	2nd Stage O/C Start A	*	*	*	*
1046	I>2 Start B	DDB_POC_2_PH_B_START	SW	PFSO	2nd Stage O/C Start B	*	*	*	*
1047	I>2 Start C	DDB_POC_2_PH_C_START	SW	PFSO	2nd Stage O/C Start C	*	*	*	*
1048	I>3 Start	DDB_POC_3_3PH_START	SW	PFSO	3rd Stage O/C Start 3ph	*	*	*	*
1049	I>3 Start A	DDB_POC_3_PH_A_START	SW	PFSO	3rd Stage O/C Start A	*	*	*	*
1050	I>3 Start B	DDB_POC_3_PH_B_START	SW	PFSO	3rd Stage O/C Start B	*	*	*	*
1051	I>3 Start C	DDB_POC_3_PH_C_START	SW	PFSO	3rd Stage O/C Start C	*	*	*	*
1052	I>4 Start	DDB_POC_4_3PH_START	SW	PFSO	4th Stage O/C Start 3ph	*	*	*	*
1053	I>4 Start A	DDB_POC_4_PH_A_START	SW	PFSO	4th Stage O/C Start A	*	*	*	*
1054	I>4 Start B	DDB_POC_4_PH_B_START	SW	PFSO	4th Stage O/C Start B	*	*	*	*
1055	I>4 Start C	DDB_POC_4_PH_C_START	SW	PFSO	4th Stage O/C Start C	*	*	*	*
1056		DDB_UNUSED	SW	UNUSED					
1057		DDB_UNUSED	SW	UNUSED					
1058		DDB_UNUSED	SW	UNUSED					
1059		DDB_UNUSED	SW	UNUSED					
1060		DDB_UNUSED	SW	UNUSED					
1061		DDB_UNUSED	SW	UNUSED					
1062		DDB_UNUSED	SW	UNUSED					
1063		DDB_UNUSED	SW	UNUSED					
1064	I2>1 Start	DDB_NPSOC_1_START	SW	PFSO	NPS Overcurrent Stage 1 Start	*	*	*	*
1065	I2>2 Start	DDB_NPSOC_2_START	SW	PFSO	NPS Overcurrent Stage 2 Start	*	*	*	*
1066	I2>3 Start	DDB_NPSOC_3_START	SW	PFSO	NPS Overcurrent Stage 3 Start	*	*	*	*
1067	I2>4 Start	DDB_NPSOC_4_START	SW	PFSO	NPS Overcurrent Stage 4 Start	*	*	*	*
1068	IA< Start	DDB_PHASE_A_UNDERCURRENT	SW	PFSO	Fast under current: Phase A	*	*	*	*
1069	IB< Start	DDB_PHASE_B_UNDERCURRENT	SW	PFSO	Fast under current: Phase B	*	*	*	*
1070	IC< Start	DDB_PHASE_C_UNDERCURRENT	SW	PFSO	Fast under current: Phase C	*	*	*	*
1071	ISEF< Start	DDB_SEF_UNDERCURRENT	SW	PFSO	ISEF< Operate	*	*	*	*
1072	IN< Start	DDB_EF_UNDERCURRENT	SW	PFSO	IN< Operate	*	*	*	*
1073	I> BlockStart	DDB_PH_BLOCKED_OC_START	SW	PFSO	I> Blocked O/C Start				
1074	IN/SEF>Blk Start	DDB_N_BLOCKED_OC_START	SW	PFSO	IN/ISEF> Blocked O/C Start				
1075	TF OC Start	DDB_THROUGH_FAULT_OC_START	SW	PFSO	Through fault START	*	*	*	*
1076		DDB_UNUSED	SW	UNUSED					
1077	TF Recorder trig	DDB_THROUGH_FAULT_RECORDER	SW	PFSO	Through fault TRIGGER	*	*	*	*
1078		DDB_UNUSED	SW	UNUSED					
1079		DDB_UNUSED	SW	UNUSED					
1080		DDB_UNUSED	SW	UNUSED					
1081		DDB_UNUSED	SW	UNUSED					
1082		DDB_UNUSED	SW	UNUSED					
1083		DDB_UNUSED	SW	UNUSED					
1084		DDB_UNUSED	SW	UNUSED					
1085		DDB_UNUSED	SW	UNUSED					
1086		DDB_UNUSED	SW	UNUSED					
1087		DDB_UNUSED	SW	UNUSED					
1088	VN>1 Start	DDB_RESOV_1_START	SW	PFSO	1st Stage Residual O/V Start	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1089	VN>2 Start	DDB_RESOV_2_START	SW	PFSO	2nd Stage Residual O/V Start	*	*	*	*
1090	VN>3 Start	DDB_RESOV_3_START	SW	PFSO	Residual O/V Stage 3 Start	*	*	*	*
1091	VN>4 Start	DDB_RESOV_4_START	SW	PFSO	Residual O/V Stage 4 Start	*	*	*	*
1092	VN>5 Start	DDB_RESOV_5_START	SW	PFSO	Residual O/V Stage 5 Start			*	*
1093	VN>6 Start	DDB_RESOV_6_START	SW	PFSO	Residual O/V Stage 6 Start			*	*
1094	V>1 Start	DDB_POV_1_3PH_START	SW	PFSO	1st Stage Phase O/V Start 3ph	*	*	*	*
1095	V>1 Start A/AB	DDB_POV_1_PH_A_START	SW	PFSO	1st Stage Phase O/V Start A/AB	*	*	*	*
1096	V>1 Start B/BC	DDB_POV_1_PH_B_START	SW	PFSO	1st Stage Phase O/V Start B/BC	*	*	*	*
1097	V>1 Start C/CA	DDB_POV_1_PH_C_START	SW	PFSO	1st Stage Phase O/V Start C/CA	*	*	*	*
1098	V>2 Start	DDB_POV_2_3PH_START	SW	PFSO	2nd Stage Phase O/V Start 3ph	*	*	*	*
1099	V>2 Start A/AB	DDB_POV_2_PH_A_START	SW	PFSO	2nd Stage Phase O/V Start A/AB	*	*	*	*
1100	V>2 Start B/BC	DDB_POV_2_PH_B_START	SW	PFSO	2nd Stage Phase O/V Start B/BC	*	*	*	*
1101	V>2 Start C/CA	DDB_POV_2_PH_C_START	SW	PFSO	2nd Stage Phase O/V Start C/CA	*	*	*	*
1102	V2>1 Start	DDB_NPSOV_1_START	SW	PFSO	NPS Over Voltage Stage 1 Start	*	*	*	*
1103	V<1 Start	DDB_PUV_1_3PH_START	SW	PFSO	1st Stage Phase U/V Start 3ph	*	*	*	*
1104	V<1 Start A/AB	DDB_PUV_1_PH_A_START	SW	PFSO	1st Stage Phase U/V Start A/AB	*	*	*	*
1105	V<1 Start B/BC	DDB_PUV_1_PH_B_START	SW	PFSO	1st Stage Phase U/V Start B/BC	*	*	*	*
1106	V<1 Start C/CA	DDB_PUV_1_PH_C_START	SW	PFSO	1st Stage Phase U/V Start C/CA	*	*	*	*
1107	V<2 Start	DDB_PUV_2_3PH_START	SW	PFSO	2nd Stage Phase U/V Start 3ph	*	*	*	*
1108	V<2 Start A/AB	DDB_PUV_2_PH_A_START	SW	PFSO	2nd Stage Phase U/V Start A/AB	*	*	*	*
1109	V<2 Start B/BC	DDB_PUV_2_PH_B_START	SW	PFSO	2nd Stage Phase U/V Start B/BC	*	*	*	*
1110	V<2 Start C/CA	DDB_PUV_2_PH_C_START	SW	PFSO	2nd Stage Phase U/V Start C/CA	*	*	*	*
1111		DDB_UNUSED	SW	UNUSED					
1112		DDB_UNUSED	SW	UNUSED					
1113		DDB_UNUSED	SW	UNUSED					
1114		DDB_UNUSED	SW	UNUSED					
1115		DDB_UNUSED	SW	UNUSED					
1116		DDB_UNUSED	SW	UNUSED					
1117		DDB_UNUSED	SW	UNUSED					
1118		DDB_UNUSED	SW	UNUSED					
1119		DDB_UNUSED	SW	UNUSED					
1120	FFail1 Start	DDB_FIELDF_1_START	SW	PFSO	Field Failure Stage 1 Start	*	*	*	*
1121	FFail2 Start	DDB_FIELDF_2_START	SW	PFSO	Field Failure Stage 2 Start	*	*	*	*
1122	PSlipz Z1 Start	DDB_POLESLZ_ZONE1_START	SW	PFSO	Pole Slip (Impedance) Zone1 Start		*	*	*
1123	PSlipz Z2 Start	DDB_POLESLZ_ZONE2_START	SW	PFSO	Pole Slip (Impedance) Zone2 Start		*	*	*
1124	PSlipz LensStart	DDB_POLESLZ_LENS_START	SW	PFSO	Pole Slip (impedance) Lens Start		*	*	*
1125	PSlipz BlindStrt	DDB_POLESLZ_BLINDER_START	SW	PFSO	Pole Slip (impedance) Blinder Start		*	*	*
1126	PSlipz ReactStrt	DDB_POLESLZ_REACT_START	SW	PFSO	Pole Slip (impedance) Reactance Line Start		*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1127	V Dep OC Start	DDB_VOLT_DEP_OC_3PH_START	SW	PFSO	Voltage Dependant Overcurrent Start 3Ph	*	*	*	*
1128	V Dep OC Start A	DDB_VOLT_DEP_OC_PH_A_START	SW	PFSO	Voltage Dependant Overcurrent Start A	*	*	*	*
1129	V Dep OC Start B	DDB_VOLT_DEP_OC_PH_B_START	SW	PFSO	Voltage Dependant Overcurrent Start B	*	*	*	*
1130	V Dep OC Start C	DDB_VOLT_DEP_OC_PH_C_START	SW	PFSO	Voltage Dependant Overcurrent Start C	*	*	*	*
1131	Z<1 Start	DDB_UNDERZ_1_3PH_START	SW	PFSO	Under Impedance 3Phase Stage 1 Start	*	*	*	*
1132	Z<1 Start A	DDB_UNDERZ_1_PH_A_START	SW	PFSO	Under Impedance Phase A Stage 1 Start	*	*	*	*
1133	Z<1 Start B	DDB_UNDERZ_1_PH_B_START	SW	PFSO	Under Impedance Phase B Stage 1 Start	*	*	*	*
1134	Z<1 Start C	DDB_UNDERZ_1_PH_C_START	SW	PFSO	Under Impedance Phase C Stage 1 Start	*	*	*	*
1135	Z<2 Start	DDB_UNDERZ_2_3PH_START	SW	PFSO	Under Impedance 3Phase Stage 2 Start	*	*	*	*
1136	Z<2 Start A	DDB_UNDERZ_2_PH_A_START	SW	PFSO	Under Impedance Phase A Stage 2 Start	*	*	*	*
1137	Z<2 Start B	DDB_UNDERZ_2_PH_B_START	SW	PFSO	Under Impedance Phase B Stage 2 Start	*	*	*	*
1138	Z<2 Start C	DDB_UNDERZ_2_PH_C_START	SW	PFSO	Under Impedance Phase C Stage 2 Start	*	*	*	*
1139	S2>1 Start	DDB_PWRNPS_1_START	SW	PFSO	NPS Overpower Stage 1 Start	*	*	*	*
1140	Power1 Start	DDB_POWER_1_START	SW	PFSO	Power Stage 1 Start	*	*	*	*
1141	Power2 Start	DDB_POWER_2_START	SW	PFSO	Power Stage 2 Start	*	*	*	*
1142	SPower1 Start	DDB_SPOWER_1_START	SW	PFSO	Sensitive A Phase Power Stage 1 Start	*	*	*	*
1143	SPower2 Start	DDB_SPOWER_2_START	SW	PFSO	Sensitive A Phase Power Stage 2 Start	*	*	*	*
1144		DDB_UNUSED	SW	UNUSED					
1145		DDB_UNUSED	SW	UNUSED					
1146		DDB_UNUSED	SW	UNUSED					
1147		DDB_UNUSED	SW	UNUSED					
1148		DDB_UNUSED	SW	UNUSED					
1149		DDB_UNUSED	SW	UNUSED					
1150		DDB_UNUSED	SW	UNUSED					
1151		DDB_UNUSED	SW	UNUSED					
1152		DDB_UNUSED	SW	UNUSED					
1153		DDB_UNUSED	SW	UNUSED					
1154		DDB_UNUSED	SW	UNUSED					
1155		DDB_UNUSED	SW	UNUSED					
1156		DDB_UNUSED	SW	UNUSED					
1157		DDB_UNUSED	SW	UNUSED					
1158		DDB_UNUSED	SW	UNUSED					
1159		DDB_UNUSED	SW	UNUSED					
1160		DDB_UNUSED	SW	UNUSED					
1161		DDB_UNUSED	SW	UNUSED					
1162		DDB_UNUSED	SW	UNUSED					
1163		DDB_UNUSED	SW	UNUSED					
1164		DDB_UNUSED	SW	UNUSED					
1165		DDB_UNUSED	SW	UNUSED					
1166		DDB_UNUSED	SW	UNUSED					
1167		DDB_UNUSED	SW	UNUSED					
1168	V/Hz>1 Start	DDB_VPERHZ_START	SW	PFSO	1st Stage Volts per Hz Start	*	*	*	*
1169	V/Hz>2 Start	DDB_VPERHZ_START2	SW	PFSO	Volts per Hz Stage 2 Start	*	*	*	*
1170	V/Hz>3 Start	DDB_VPERHZ_START3	SW	PFSO	Volts per Hz Stage 3 Start	*	*	*	*
1171	V/Hz>4 Start	DDB_VPERHZ_START4	SW	PFSO	Volts per Hz Stage 4 Start	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1172	F<1 Start	DDB_UFREQ_1_START	SW	PFSO	Under Frequency Stage 1 Start	*	*	*	*
1173	F<2 Start	DDB_UFREQ_2_START	SW	PFSO	Under Frequency Stage 2 Start	*	*	*	*
1174	F<3 Start	DDB_UFREQ_3_START	SW	PFSO	Under Frequency Stage 3 Start	*	*	*	*
1175	F<4 Start	DDB_UFREQ_4_START	SW	PFSO	Under Frequency Stage 4 Start	*	*	*	*
1176	F>1 Start	DDB_OFREQ_1_START	SW	PFSO	Over Frequency Stage 1 Start	*	*	*	*
1177	F>2 Start	DDB_OFREQ_2_START	SW	PFSO	Over Frequency Stage 2 Start	*	*	*	*
1178	Freq Band1 Start	DDB_TAF1_START1	SW	PFSO	Turbine Abnormal Frequency Band 1 Start	*	*	*	*
1179	Freq Band2 Start	DDB_TAF1_START2	SW	PFSO	Turbine Abnormal Frequency Band 2 Start	*	*	*	*
1180	Freq Band3 Start	DDB_TAF1_START3	SW	PFSO	Turbine Abnormal Frequency Band 3 Start	*	*	*	*
1181	Freq Band4 Start	DDB_TAF1_START4	SW	PFSO	Turbine Abnormal Frequency Band 4 Start	*	*	*	*
1182	Freq Band5 Start	DDB_TAF1_START5	SW	PFSO	Turbine Abnormal Frequency Band 5 Start	*	*	*	*
1183	Freq Band6 Start	DDB_TAF1_START6	SW	PFSO	Turbine Abnormal Frequency Band 6 Start	*	*	*	*
1184	df/dt>1 Start	DDB_DFDT_1_START	SW	PFSO	df/dt>1 Start	*	*	*	*
1185	df/dt>2 Start	DDB_DFDT_2_START	SW	PFSO	df/dt>2 Start	*	*	*	*
1186	df/dt>3 Start	DDB_DFDT_3_START	SW	PFSO	df/dt>3 Start	*	*	*	*
1187	df/dt>4 Start	DDB_DFDT_4_START	SW	PFSO	df/dt>4 Start	*	*	*	*
1188		DDB_UNUSED	SW	UNUSED					
1189		DDB_UNUSED	SW	UNUSED					
1190		DDB_UNUSED	SW	UNUSED					
1191		DDB_UNUSED	SW	UNUSED					
1192		DDB_UNUSED	SW	UNUSED					
1193		DDB_UNUSED	SW	UNUSED					
1194		DDB_UNUSED	SW	UNUSED					
1195		DDB_UNUSED	SW	UNUSED					
1196		DDB_UNUSED	SW	UNUSED					
1197		DDB_UNUSED	SW	UNUSED					
1198		DDB_UNUSED	SW	UNUSED					
1199		DDB_UNUSED	SW	UNUSED					
1200	Hot Spot>1 Start	DDB_XFORMER_HOT_SPOT_1_START	SW	PFSO	HotSpot>1 Start	*	*	*	*
1201	Hot Spot>2 Start	DDB_XFORMER_HOT_SPOT_2_START	SW	PFSO	HotSpot>2 Start	*	*	*	*
1202	Hot Spot>3 Start	DDB_XFORMER_HOT_SPOT_3_START	SW	PFSO	HotSpot>3 Start	*	*	*	*
1203	Top Oil>1 start	DDB_XFORMER_TOP_OIL_1_START	SW	PFSO	Top Oil>1 Start	*	*	*	*
1204	Top Oil>2 start	DDB_XFORMER_TOP_OIL_2_START	SW	PFSO	Top Oil>2 Start	*	*	*	*
1205	Top Oil>3 start	DDB_XFORMER_TOP_OIL_3_START	SW	PFSO	Top Oil>3 Start	*	*	*	*
1206	DLR I>1 Start	DDB_DLR_AMP_1_START	SW	PFSO	DLR Trip 1 Start				
1207	DLR I>2 Start	DDB_DLR_AMP_2_START	SW	PFSO	DLR Trip 2 Start				
1208	DLR I>3 Start	DDB_DLR_AMP_3_START	SW	PFSO	DLR Trip 3 Start				
1209	DLR I>4 Start	DDB_DLR_AMP_4_START	SW	PFSO	DLR Trip 4 Start				
1210	DLR I>5 Start	DDB_DLR_AMP_5_START	SW	PFSO	DLR Trip 5 Start				
1211	DLR I>6 Start	DDB_DLR_AMP_6_START	SW	PFSO	DLR Trip 6 Start				
1212		DDB_UNUSED	SW	UNUSED					
1213		DDB_UNUSED	SW	UNUSED					
1214		DDB_UNUSED	SW	UNUSED					
1215		DDB_UNUSED	SW	UNUSED					
1216		DDB_UNUSED	SW	UNUSED					
1217		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1218		DDB_UNUSED	SW	UNUSED					
1219		DDB_UNUSED	SW	UNUSED					
1220		DDB_UNUSED	SW	UNUSED					
1221		DDB_UNUSED	SW	UNUSED					
1222		DDB_UNUSED	SW	UNUSED					
1223		DDB_UNUSED	SW	UNUSED					
1224		DDB_UNUSED	SW	UNUSED					
1225		DDB_UNUSED	SW	UNUSED					
1226		DDB_UNUSED	SW	UNUSED					
1227		DDB_UNUSED	SW	UNUSED					
1228		DDB_UNUSED	SW	UNUSED					
1229		DDB_UNUSED	SW	UNUSED					
1230		DDB_UNUSED	SW	UNUSED					
1231		DDB_UNUSED	SW	UNUSED					
1232	CLI1 Alarm Start	DDB_CL_INPUT_1_ALARM_START	SW	PFSO	Current Loop Input 1 Alarm Start	*	*	*	*
1233	CLI2 Alarm Start	DDB_CL_INPUT_2_ALARM_START	SW	PFSO	Current Loop Input 2 Alarm Start	*	*	*	*
1234	CLI3 Alarm Start	DDB_CL_INPUT_3_ALARM_START	SW	PFSO	Current Loop Input 3 Alarm Start	*	*	*	*
1235	CLI4 Alarm Start	DDB_CL_INPUT_4_ALARM_START	SW	PFSO	Current Loop Input 4 Alarm Start	*	*	*	*
1236	CLI1 Trip Start	DDB_CL_INPUT_1_TRIP_START	SW	PFSO	Current Loop Input 1 Trip Start	*	*	*	*
1237	CLI2 Trip Start	DDB_CL_INPUT_2_TRIP_START	SW	PFSO	Current Loop Input 2 Trip Start	*	*	*	*
1238	CLI3 Trip Start	DDB_CL_INPUT_3_TRIP_START	SW	PFSO	Current Loop Input 3 Trip Start	*	*	*	*
1239	CLI4 Trip Start	DDB_CL_INPUT_4_TRIP_START	SW	PFSO	Current Loop Input 4 Trip Start	*	*	*	*
1240	UI pw level 1	DDB_UIPASSWORD_ONE	SW	PFSO	Indicate the current UI Password Level	*	*	*	*
1241	UI pw level 2	DDB_UIPASSWORD_TWO	SW	PFSO	Indicate the current UI Password Level 2	*	*	*	*
1242	FCurPW level 1	DDB_FCURPASSWORD_ONE	SW	PFSO	Indicate the Courier front port Password Level	*	*	*	*
1243	FCurPW level 2	DDB_FCURPASSWORD_TWO	SW	PFSO	Indicate the Courier front port Password Level 2	*	*	*	*
1244	Remote1 level 1	DDB_REMOTEPASSWORD_ONE	SW	PFSO	Indicate the first rear port Password Level	*	*	*	*
1245	Remote1 level 2	DDB_REMOTEPASSWORD_TWO	SW	PFSO	Indicate the first rear port Password Level 2	*	*	*	*
1246	Remote2 level 1	DDB_REMOTE2PASSWORD_ONE	SW	PFSO	indicate the second rear port Password Level	*	*	*	*
1247	Remote2 level 2	DDB_REMOTE2PASSWORD_TWO	SW	PFSO	indicate the second rear port Password Level 2	*	*	*	*
1248	VTS Fast Block	DDB_VTS_FAST_BLOCK	SW	PFSO	VTS Fast Block	*	*	*	*
1249	VTS Slow Block	DDB_VTS_SLOW_BLOCK	SW	PFSO	VTS Slow Block	*	*	*	*
1250	VTS Acc Ind	DDB_VTS_ACCELERATE_INPUT	FL	HIDDEN	VTS Accelerate Indication	*	*	*	*
1251	VTS Volt Dep	DDB_VTS_ANY_VOLTAGE_DEP_FN	FL	HIDDEN	Any Voltage Dependent	*	*	*	*
1252	VTS IA>	DDB_VTS_IA_OPERATED	SW	HIDDEN	Ia Over Threshold	*	*	*	*
1253	VTS IB>	DDB_VTS_IB_OPERATED	SW	HIDDEN	Ib Over Threshold	*	*	*	*
1254	VTS IC>	DDB_VTS_IC_OPERATED	SW	HIDDEN	Ic Over Threshold	*	*	*	*
1255	VTS VA>	DDB_VTS_VA_OPERATED	SW	HIDDEN	Va Over Threshold	*	*	*	*
1256	VTS VB>	DDB_VTS_VB_OPERATED	SW	HIDDEN	Vb Over Threshold	*	*	*	*
1257	VTS VC>	DDB_VTS_VC_OPERATED	SW	HIDDEN	Vc Over Threshold	*	*	*	*
1258	VTS I2>	DDB_VTS_I2_OPERATED	SW	HIDDEN	I2 Over Threshold	*	*	*	*
1259	VTS V2>	DDB_VTS_V2_OPERATED	SW	HIDDEN	V2 Over Threshold	*	*	*	*
1260	VTS IA delta>	DDB_VTS_DELTA_IA_OPERATED	SW	HIDDEN	Superimposed Ia Over Threshold	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1261	VTS IB delta>	DDB_VTS_DELTA_IB_OPERATED	SW	HIDDEN	Superimposed Ib Over Threshold	*	*	*	*
1262	VTS IC delta>	DDB_VTS_DELTA_IC_OPERATED	SW	HIDDEN	Superimposed Ic Over Threshold	*	*	*	*
1263	CTS-1 Block	DDB_CTS_BLOCK	SW	PFSO	CTS-1 Block	*	*	*	*
1264	CTS-2 Block	DDB_CTS_2_BLOCK	SW	PFSO	CTS-2 Block		*	*	*
1265	Diff CTS BLK	DDB_DIFF_CTS_BLK	SW	PFSO	differential CTS		*	*	*
1266	Diff CTS CT1	DDB_DIFF_CTS_CT1	SW	PFSO	differential CTS		*	*	*
1267	Diff CTS CT2	DDB_DIFF_CTS_CT2	SW	PFSO	differential CTS		*	*	*
1268		DDB_UNUSED	SW	UNUSED					
1269	CctFail Blk A	DDB_CIR_FLT_A	SW	PFSO	Circuitry Fault Alarm A		*	*	*
1270	CctFail Blk B	DDB_CIR_FLT_B	SW	PFSO	Circuitry Fault Alarm B		*	*	*
1271	CctFail Blk C	DDB_CIR_FLT_C	SW	PFSO	Circuitry Fault Alarm C		*	*	*
1272	2nd Har Blk A	DDB_2ND_HAR_BLKA	SW	PFSO	2nd Harmonic A		*	*	*
1273	2nd Har Blk B	DDB_2ND_HAR_BLKB	SW	PFSO	2nd Harmonic B		*	*	*
1274	2nd Har Blk C	DDB_2ND_HAR_BLKC	SW	PFSO	2nd Harmonic C		*	*	*
1275	5nd Har Blk A	DDB_5TH_HAR_BLKA	SW	PFSO	5th Har Blk A		*	*	*
1276	5nd Har Blk B	DDB_5TH_HAR_BLKB	SW	PFSO	5th Har Blk B		*	*	*
1277	5nd Har Blk C	DDB_5TH_HAR_BLKC	SW	PFSO	5th Har Blk C		*	*	*
1278	Control Trip	DDB_CONTROL_TRIP	SW	PFSO	Control Trip	*	*	*	*
1279	Control Close	DDB_CONTROL_CLOSE	SW	PFSO	Control Close	*	*	*	*
1280	Close in Prog	DDB_CONTROL_CLOSE_IN_PROGRESS	SW	PFSO	Control Close in Progress	*	*	*	*
1281	Lockout Alarm	DDB_CB_LOCKOUT_ALARM	SW	PFSO	Composite Lockout Alarm	*	*	*	*
1282	CB Open 3 ph	DDB_CB_OPEN	SW	PFSO	3 ph CB Open	*	*	*	*
1283	CB Closed 3 ph	DDB_CB_CLOSED	SW	PFSO	3 ph CB Closed	*	*	*	*
1284	All Poles Dead	DDB_ALL_POLEDEAD	SW	PFSO	All Poles Dead	*	*	*	*
1285	Any Pole Dead	DDB_ANY_POLEDEAD	SW	PFSO	Any Pole Dead	*	*	*	*
1286	Pole Dead A	DDB_PHASE_A_POLEDEAD	SW	PFSO	Phase A Pole Dead	*	*	*	*
1287	Pole Dead B	DDB_PHASE_B_POLEDEAD	SW	PFSO	Phase B Pole Dead	*	*	*	*
1288	Pole Dead C	DDB_PHASE_C_POLEDEAD	SW	PFSO	Phase C Pole Dead	*	*	*	*
1289	BFail SEF Trip-1	DDB_CBF_SEF_STAGE_TRIP	FL	HIDDEN	CBF Current Prot SEF Stage Trip	*	*	*	*
1290	BFail Non I Tr-1	DDB_CBF_NON_CURRENT_STAGE_TRIP	FL	HIDDEN	CBF Non Current Prot Stage Trip	*	*	*	*
1291	BFail SEF Trip	DDB_CURRENT_PROT_SEF_TRIP	FL	HIDDEN	CBF Current Prot SEF Trip	*	*	*	*
1292	BFail Non I Trip	DDB_CBF_NON_CURRENT_PROT_TRIP	FL	HIDDEN	CBF Non Current Prot Trip	*	*	*	*
1293	Freq High	DDB_FREQ_ABOVE_RANGE_LIMIT	SW	PFSO	Freq High	*	*	*	*
1294	Freq Low	DDB_FREQ_BELOW_RANGE_LIMIT	SW	PFSO	Freq Low	*	*	*	*
1295	Freq Not found	DDB_FREQ_NOT_FOUND	SW	PFSO	Freq Not Found	*	*	*	*
1296		DDB_UNUSED	SW	UNUSED					
1297	64S F Band Block	DDB_STEFI_LOW_F_BLOCK	SW	PFSO	64S 100% Stator Earth Fault - System frequency in blocking band				*
1298	64S Fail	DDB_STEFI_FAIL	SW	PFSO	64S 100% Stator Earth Fault - Injection failure				*
1299	Reconnection	DDB_RECONNECTION_OUTPUT	SW	PFSO	Reconnection Time Delay Output				
1300	Recon LOM-1	DDB_RECONNECT_UNQUAL_LOM	FL	HIDDEN	Reconnect LOM (Unqualified)				
1301	Recon Disable-1	DDB_RECONNECT_UNQUAL_DISABLE	FL	HIDDEN	Reconnect Disable (Unqualified)				
1302	Recon LOM	DDB_RECONNECT_LOM	FL	HIDDEN	Reconnect LOM				
1303	Recon Disable	DDB_RECONNECT_DISABLE	FL	HIDDEN	Reconnect Disable				
1304	RTD 1 Alarm	DDB_RTD_1_ALARM	SW	PFSO	RTD 1 Alarm	*	*	*	*
1305	RTD 2 Alarm	DDB_RTD_2_ALARM	SW	PFSO	RTD 2 Alarm	*	*	*	*
1306	RTD 3 Alarm	DDB_RTD_3_ALARM	SW	PFSO	RTD 3 Alarm	*	*	*	*
1307	RTD 4 Alarm	DDB_RTD_4_ALARM	SW	PFSO	RTD 4 Alarm	*	*	*	*
1308	RTD 5 Alarm	DDB_RTD_5_ALARM	SW	PFSO	RTD 5 Alarm	*	*	*	*
1309	RTD 6 Alarm	DDB_RTD_6_ALARM	SW	PFSO	RTD 6 Alarm	*	*	*	*
1310	RTD 7 Alarm	DDB_RTD_7_ALARM	SW	PFSO	RTD 7 Alarm	*	*	*	*

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1311	RTD 8 Alarm	DDB_RTD_8_ALARM	SW	PFSO	RTD 8 Alarm	*	*	*	*
1312	RTD 9 Alarm	DDB_RTD_9_ALARM	SW	PFSO	RTD 9 Alarm	*	*	*	*
1313	RTD 10 Alarm	DDB_RTD_10_ALARM	SW	PFSO	RTD 10 Alarm	*	*	*	*
1314	Blk Rmt. CB Ops	DDB_BLOCK_REMOTE_CB_OPS	PSL	PFSI	Blocks remote CB Trip/Close commands when asserted	*	*	*	*
1315		DDB_UNUSED	SW	UNUSED					
1316		DDB_UNUSED	SW	UNUSED					
1317		DDB_UNUSED	SW	UNUSED					
1318		DDB_UNUSED	SW	UNUSED					
1319		DDB_UNUSED	SW	UNUSED					
1320		DDB_UNUSED	SW	UNUSED					
1321		DDB_UNUSED	SW	UNUSED					
1322		DDB_UNUSED	SW	UNUSED					
1323		DDB_UNUSED	SW	UNUSED					
1324		DDB_UNUSED	SW	UNUSED					
1325		DDB_UNUSED	SW	UNUSED					
1326		DDB_UNUSED	SW	UNUSED					
1327		DDB_UNUSED	SW	UNUSED					
1328	Live Gen	DDB_SYSCHECKS_GEN_LIVE	SW	PFSO	Live Gen	*	*	*	*
1329	Dead Gen	DDB_SYSCHECKS_GEN_DEAD	SW	PFSO	Dead Gen	*	*	*	*
1330	Live Bus	DDB_SYSCHECKS_BUS_LIVE	SW	PFSO	Live Bus	*	*	*	*
1331	Dead Bus	DDB_SYSCHECKS_BUS_DEAD	SW	PFSO	Dead Bus	*	*	*	*
1332	Check Sync 1 OK	DDB_CHECKSYNC_1_OK	SW	PFSO	Check Sync 1 OK	*	*	*	*
1333	Check Sync 2 OK	DDB_CHECKSYNC_2_OK	SW	PFSO	Check Sync 2 OK	*	*	*	*
1334		DDB_UNUSED	SW	UNUSED					
1335	SysChks Inactive	DDB_SYSCHECKS_INACTIVE	SW	PFSO	SysChks Inactive	*	*	*	*
1336	CS1 Enabled	DDB_CHECKSYNC_1_ENABLED	PSL	PFSI	CS1 Enabled	*	*	*	*
1337	CS2 Enabled	DDB_CHECKSYNC_2_ENABLED	PSL	PFSI	CS2 Enabled	*	*	*	*
1338	SysSplit Enabled	DDB_SYSTEM_SPLIT_ENABLED	PSL	PFSI	SysSplit Enabled	*	*	*	*
1339	CS1 Slipfreq>	DDB_CS1_SLIP_ABOVE_SETTING	SW	PFSO	Check Synch 1 Slip > Setting	*	*	*	*
1340	CS1 Slipfreq<	DDB_CS1_SLIP_BELOW_SETTING	SW	PFSO	Check Synch 1 Slip < Setting	*	*	*	*
1341	CS2 Slipfreq>	DDB_CS2_SLIP_ABOVE_SETTING	SW	PFSO	Check Synch 2 Slip > Setting	*	*	*	*
1342	CS2 Slipfreq<	DDB_CS2_SLIP_BELOW_SETTING	SW	PFSO	Check Synch 2 Slip < Setting	*	*	*	*
1343	CS Vgen<	DDB_SYSCHECKS_VGEN_UV	SW	PFSO	Gen volts less than CS undervoltage setting	*	*	*	*
1344	CS Vbus<	DDB_SYSCHECKS_VBUS_UV	SW	PFSO	Bus volts less than CS undervoltage setting	*	*	*	*
1345	CS Vgen>	DDB_SYSCHECKS_VGEN_OV	SW	PFSO	Gen volts greater than CS overvoltage setting	*	*	*	*
1346	CS Vbus>	DDB_SYSCHECKS_VBUS_OV	SW	PFSO	Bus volts greater than CS overvoltage setting	*	*	*	*
1347	CS Freq Low	DDB_SYSCHECKS_FGEN_UF	SW	PFSO	Gen freq less than CS underfreq setting	*	*	*	*
1348	CS Freq High	DDB_SYSCHECKS_FGEN_OF	SW	PFSO	Gen freq greater than CS overfreq setting	*	*	*	*
1349	CS Vgen>Vbus	DDB_SYSCHECKS_VGEN_DIFF_HIGH	SW	PFSO	Gen volts greater than (bus volts + CS diff voltage setting)	*	*	*	*
1350	CS Vgen<Vbus	DDB_SYSCHECKS_VBUS_DIFF_HIGH	SW	PFSO	Bus volts greater than (line volts + CS diff voltage setting)	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1351	CS1 Fgen>Fbus	DDB_CS1_GEN_FREQ_GT_BUS_FREQ	SW	PFSO	Gen freq greater than (bus freq + CS1 slip freq setting)	*	*	*	*
1352	CS1 Fgen<Fbus	DDB_CS1_GEN_FREQ_LT_BUS_FREQ	SW	PFSO	Bus freq greater than (line freq + CS1 slip freq setting)	*	*	*	*
1353	CS1 Ang Not OK +	DDB_CS1_ANG_NOT_OK_POS	SW	PFSO	Gen angle in range (CS1 ang setting to +180 deg)	*	*	*	*
1354	CS1 Ang Not OK -	DDB_CS1_ANG_NOT_OK_NEG	SW	PFSO	Gen angle in range (-CS1 ang setting to -180 deg)	*	*	*	*
1355	CS2 Fgen>Fbus	DDB_CS2_GEN_FREQ_GT_BUS_FREQ	SW	PFSO	Gen freq greater than (bus freq + CS2 slip freq setting)	*	*	*	*
1356	CS2 Fgen<Fbus	DDB_CS2_GEN_FREQ_LT_BUS_FREQ	SW	PFSO	Bus freq greater than (gen freq + CS2 slip freq setting)	*	*	*	*
1357	CS2 Ang Not OK +	DDB_CS2_ANG_NOT_OK_POS	SW	PFSO	Gen angle in range (CS2 angle setting to +180 deg)	*	*	*	*
1358	CS2 Ang Not OK -	DDB_CS2_ANG_NOT_OK_NEG	SW	PFSO	Gen angle in range (-CS2 angle setting to -180 deg)	*	*	*	*
1359	CS Ang Rot ACW	DDB_SYSCHECKS_ANG_ACW	SW	PFSO	Gen/Bus phase angle is rotating anti-clockwise	*	*	*	*
1360	CS Ang Rot CW	DDB_SYSCHECKS_ANG_CW	SW	PFSO	Gen/Bus phase angle is rotating clockwise	*	*	*	*
1361	CS Guard Enabled	DDB_CHECKSYNC_GUARD_ON	SW	PFSO	Check Synch Guard on	*	*	*	*
1362	Man Check Synch	DDB_MAN_SYSCHECKS	PSL	PFSI	Manual check synchronization conditions are satisfied	*	*	*	*
1363	CS Guard Enable	DDB_CHECKSYNC_GUARD_IN	PSL	PFSI	Check Synch Guard input	*	*	*	*
1364		DDB_UNUSED	SW	UNUSED					
1365		DDB_UNUSED	SW	UNUSED					
1366		DDB_UNUSED	SW	UNUSED					
1367		DDB_UNUSED	SW	UNUSED					
1368		DDB_UNUSED	SW	UNUSED					
1369		DDB_UNUSED	SW	UNUSED					
1370		DDB_UNUSED	SW	UNUSED					
1371		DDB_UNUSED	SW	UNUSED					
1372		DDB_UNUSED	SW	UNUSED					
1373		DDB_UNUSED	SW	UNUSED					
1374		DDB_UNUSED	SW	UNUSED					
1375		DDB_UNUSED	SW	UNUSED					
1376	Control Input 1	DDB_CONTROL_1	SW	CONTROL	Control Input 1	*	*	*	*
1377	Control Input 2	DDB_CONTROL_2	SW	CONTROL	Control Input 2	*	*	*	*
1378	Control Input 3	DDB_CONTROL_3	SW	CONTROL	Control Input 3	*	*	*	*
1379	Control Input 4	DDB_CONTROL_4	SW	CONTROL	Control Input 4	*	*	*	*
1380	Control Input 5	DDB_CONTROL_5	SW	CONTROL	Control Input 5	*	*	*	*
1381	Control Input 6	DDB_CONTROL_6	SW	CONTROL	Control Input 6	*	*	*	*
1382	Control Input 7	DDB_CONTROL_7	SW	CONTROL	Control Input 7	*	*	*	*
1383	Control Input 8	DDB_CONTROL_8	SW	CONTROL	Control Input 8	*	*	*	*
1384	Control Input 9	DDB_CONTROL_9	SW	CONTROL	Control Input 9	*	*	*	*
1385	Control Input 10	DDB_CONTROL_10	SW	CONTROL	Control Input 10	*	*	*	*
1386	Control Input 11	DDB_CONTROL_11	SW	CONTROL	Control Input 11	*	*	*	*
1387	Control Input 12	DDB_CONTROL_12	SW	CONTROL	Control Input 12	*	*	*	*
1388	Control Input 13	DDB_CONTROL_13	SW	CONTROL	Control Input 13	*	*	*	*
1389	Control Input 14	DDB_CONTROL_14	SW	CONTROL	Control Input 14	*	*	*	*
1390	Control Input 15	DDB_CONTROL_15	SW	CONTROL	Control Input 15	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1391	Control Input 16	DDB_CONTROL_16	SW	CONTROL	Control Input 16	*	*	*	*
1392	Control Input 17	DDB_CONTROL_17	SW	CONTROL	Control Input 17	*	*	*	*
1393	Control Input 18	DDB_CONTROL_18	SW	CONTROL	Control Input 18	*	*	*	*
1394	Control Input 19	DDB_CONTROL_19	SW	CONTROL	Control Input 19	*	*	*	*
1395	Control Input 20	DDB_CONTROL_20	SW	CONTROL	Control Input 20	*	*	*	*
1396	Control Input 21	DDB_CONTROL_21	SW	CONTROL	Control Input 21	*	*	*	*
1397	Control Input 22	DDB_CONTROL_22	SW	CONTROL	Control Input 22	*	*	*	*
1398	Control Input 23	DDB_CONTROL_23	SW	CONTROL	Control Input 23	*	*	*	*
1399	Control Input 24	DDB_CONTROL_24	SW	CONTROL	Control Input 24	*	*	*	*
1400	Control Input 25	DDB_CONTROL_25	SW	CONTROL	Control Input 25	*	*	*	*
1401	Control Input 26	DDB_CONTROL_26	SW	CONTROL	Control Input 26	*	*	*	*
1402	Control Input 27	DDB_CONTROL_27	SW	CONTROL	Control Input 27	*	*	*	*
1403	Control Input 28	DDB_CONTROL_28	SW	CONTROL	Control Input 28	*	*	*	*
1404	Control Input 29	DDB_CONTROL_29	SW	CONTROL	Control Input 29	*	*	*	*
1405	Control Input 30	DDB_CONTROL_30	SW	CONTROL	Control Input 30	*	*	*	*
1406	Control Input 31	DDB_CONTROL_31	SW	CONTROL	Control Input 31	*	*	*	*
1407	Control Input 32	DDB_CONTROL_32	SW	CONTROL	Control Input 32	*	*	*	*
1408	Virtual Input 01	DDB_GOOSEIN_1	SW	GOOSEIN	Virtual Input 01	*	*	*	*
1409	Virtual Input 02	DDB_GOOSEIN_2	SW	GOOSEIN	Virtual Input 02	*	*	*	*
1410	Virtual Input 03	DDB_GOOSEIN_3	SW	GOOSEIN	Virtual Input 03	*	*	*	*
1411	Virtual Input 04	DDB_GOOSEIN_4	SW	GOOSEIN	Virtual Input 04	*	*	*	*
1412	Virtual Input 05	DDB_GOOSEIN_5	SW	GOOSEIN	Virtual Input 05	*	*	*	*
1413	Virtual Input 06	DDB_GOOSEIN_6	SW	GOOSEIN	Virtual Input 06	*	*	*	*
1414	Virtual Input 07	DDB_GOOSEIN_7	SW	GOOSEIN	Virtual Input 07	*	*	*	*
1415	Virtual Input 08	DDB_GOOSEIN_8	SW	GOOSEIN	Virtual Input 08	*	*	*	*
1416	Virtual Input 09	DDB_GOOSEIN_9	SW	GOOSEIN	Virtual Input 09	*	*	*	*
1417	Virtual Input 10	DDB_GOOSEIN_10	SW	GOOSEIN	Virtual Input 10	*	*	*	*
1418	Virtual Input 11	DDB_GOOSEIN_11	SW	GOOSEIN	Virtual Input 11	*	*	*	*
1419	Virtual Input 12	DDB_GOOSEIN_12	SW	GOOSEIN	Virtual Input 12	*	*	*	*
1420	Virtual Input 13	DDB_GOOSEIN_13	SW	GOOSEIN	Virtual Input 13	*	*	*	*
1421	Virtual Input 14	DDB_GOOSEIN_14	SW	GOOSEIN	Virtual Input 14	*	*	*	*
1422	Virtual Input 15	DDB_GOOSEIN_15	SW	GOOSEIN	Virtual Input 15	*	*	*	*
1423	Virtual Input 16	DDB_GOOSEIN_16	SW	GOOSEIN	Virtual Input 16	*	*	*	*
1424	Virtual Input 17	DDB_GOOSEIN_17	SW	GOOSEIN	Virtual Input 17	*	*	*	*
1425	Virtual Input 18	DDB_GOOSEIN_18	SW	GOOSEIN	Virtual Input 18	*	*	*	*
1426	Virtual Input 19	DDB_GOOSEIN_19	SW	GOOSEIN	Virtual Input 19	*	*	*	*
1427	Virtual Input 20	DDB_GOOSEIN_20	SW	GOOSEIN	Virtual Input 20	*	*	*	*
1428	Virtual Input 21	DDB_GOOSEIN_21	SW	GOOSEIN	Virtual Input 21	*	*	*	*
1429	Virtual Input 22	DDB_GOOSEIN_22	SW	GOOSEIN	Virtual Input 22	*	*	*	*
1430	Virtual Input 23	DDB_GOOSEIN_23	SW	GOOSEIN	Virtual Input 23	*	*	*	*
1431	Virtual Input 24	DDB_GOOSEIN_24	SW	GOOSEIN	Virtual Input 24	*	*	*	*
1432	Virtual Input 25	DDB_GOOSEIN_25	SW	GOOSEIN	Virtual Input 25	*	*	*	*
1433	Virtual Input 26	DDB_GOOSEIN_26	SW	GOOSEIN	Virtual Input 26	*	*	*	*
1434	Virtual Input 27	DDB_GOOSEIN_27	SW	GOOSEIN	Virtual Input 27	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1435	Virtual Input 28	DDB_GOOSEIN_28	SW	GOOSEIN	Virtual Input 28	*	*	*	*
1436	Virtual Input 29	DDB_GOOSEIN_29	SW	GOOSEIN	Virtual Input 29	*	*	*	*
1437	Virtual Input 30	DDB_GOOSEIN_30	SW	GOOSEIN	Virtual Input 30	*	*	*	*
1438	Virtual Input 31	DDB_GOOSEIN_31	SW	GOOSEIN	Virtual Input 31	*	*	*	*
1439	Virtual Input 32	DDB_GOOSEIN_32	SW	GOOSEIN	Virtual Input 32	*	*	*	*
1440	Virtual Input 33	DDB_GOOSEIN_33	SW	GOOSEIN	Virtual Input 33	*	*	*	*
1441	Virtual Input 34	DDB_GOOSEIN_34	SW	GOOSEIN	Virtual Input 34	*	*	*	*
1442	Virtual Input 35	DDB_GOOSEIN_35	SW	GOOSEIN	Virtual Input 35	*	*	*	*
1443	Virtual Input 36	DDB_GOOSEIN_36	SW	GOOSEIN	Virtual Input 36	*	*	*	*
1444	Virtual Input 37	DDB_GOOSEIN_37	SW	GOOSEIN	Virtual Input 37	*	*	*	*
1445	Virtual Input 38	DDB_GOOSEIN_38	SW	GOOSEIN	Virtual Input 38	*	*	*	*
1446	Virtual Input 39	DDB_GOOSEIN_39	SW	GOOSEIN	Virtual Input 39	*	*	*	*
1447	Virtual Input 40	DDB_GOOSEIN_40	SW	GOOSEIN	Virtual Input 40	*	*	*	*
1448	Virtual Input 41	DDB_GOOSEIN_41	SW	GOOSEIN	Virtual Input 41	*	*	*	*
1449	Virtual Input 42	DDB_GOOSEIN_42	SW	GOOSEIN	Virtual Input 42	*	*	*	*
1450	Virtual Input 43	DDB_GOOSEIN_43	SW	GOOSEIN	Virtual Input 43	*	*	*	*
1451	Virtual Input 44	DDB_GOOSEIN_44	SW	GOOSEIN	Virtual Input 44	*	*	*	*
1452	Virtual Input 45	DDB_GOOSEIN_45	SW	GOOSEIN	Virtual Input 45	*	*	*	*
1453	Virtual Input 46	DDB_GOOSEIN_46	SW	GOOSEIN	Virtual Input 46	*	*	*	*
1454	Virtual Input 47	DDB_GOOSEIN_47	SW	GOOSEIN	Virtual Input 47	*	*	*	*
1455	Virtual Input 48	DDB_GOOSEIN_48	SW	GOOSEIN	Virtual Input 48	*	*	*	*
1456	Virtual Input 49	DDB_GOOSEIN_49	SW	GOOSEIN	Virtual Input 49	*	*	*	*
1457	Virtual Input 50	DDB_GOOSEIN_50	SW	GOOSEIN	Virtual Input 50	*	*	*	*
1458	Virtual Input 51	DDB_GOOSEIN_51	SW	GOOSEIN	Virtual Input 51	*	*	*	*
1459	Virtual Input 52	DDB_GOOSEIN_52	SW	GOOSEIN	Virtual Input 52	*	*	*	*
1460	Virtual Input 53	DDB_GOOSEIN_53	SW	GOOSEIN	Virtual Input 53	*	*	*	*
1461	Virtual Input 54	DDB_GOOSEIN_54	SW	GOOSEIN	Virtual Input 54	*	*	*	*
1462	Virtual Input 55	DDB_GOOSEIN_55	SW	GOOSEIN	Virtual Input 55	*	*	*	*
1463	Virtual Input 56	DDB_GOOSEIN_56	SW	GOOSEIN	Virtual Input 56	*	*	*	*
1464	Virtual Input 57	DDB_GOOSEIN_57	SW	GOOSEIN	Virtual Input 57	*	*	*	*
1465	Virtual Input 58	DDB_GOOSEIN_58	SW	GOOSEIN	Virtual Input 58	*	*	*	*
1466	Virtual Input 59	DDB_GOOSEIN_59	SW	GOOSEIN	Virtual Input 59	*	*	*	*
1467	Virtual Input 60	DDB_GOOSEIN_60	SW	GOOSEIN	Virtual Input 60	*	*	*	*
1468	Virtual Input 61	DDB_GOOSEIN_61	SW	GOOSEIN	Virtual Input 61	*	*	*	*
1469	Virtual Input 62	DDB_GOOSEIN_62	SW	GOOSEIN	Virtual Input 62	*	*	*	*
1470	Virtual Input 63	DDB_GOOSEIN_63	SW	GOOSEIN	Virtual Input 63	*	*	*	*
1471	Virtual Input 64	DDB_GOOSEIN_64	SW	GOOSEIN	Virtual Input 64	*	*	*	*
1472		DDB_UNUSED	SW	UNUSED					
1473		DDB_UNUSED	SW	UNUSED					
1474		DDB_UNUSED	SW	UNUSED					
1475		DDB_UNUSED	SW	UNUSED					
1476		DDB_UNUSED	SW	UNUSED					
1477		DDB_UNUSED	SW	UNUSED					
1478		DDB_UNUSED	SW	UNUSED					
1479		DDB_UNUSED	SW	UNUSED					
1480		DDB_UNUSED	SW	UNUSED					
1481		DDB_UNUSED	SW	UNUSED					
1482		DDB_UNUSED	SW	UNUSED					
1483		DDB_UNUSED	SW	UNUSED					
1484		DDB_UNUSED	SW	UNUSED					
1485		DDB_UNUSED	SW	UNUSED					
1486		DDB_UNUSED	SW	UNUSED					
1487		DDB_UNUSED	SW	UNUSED					
1488		DDB_UNUSED	SW	UNUSED					
1489		DDB_UNUSED	SW	UNUSED					
1490		DDB_UNUSED	SW	UNUSED					
1491		DDB_UNUSED	SW	UNUSED					
1492		DDB_UNUSED	SW	UNUSED					
1493		DDB_UNUSED	SW	UNUSED					
1494		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1495		DDB_UNUSED	SW	UNUSED					
1496		DDB_UNUSED	SW	UNUSED					
1497		DDB_UNUSED	SW	UNUSED					
1498		DDB_UNUSED	SW	UNUSED					
1499		DDB_UNUSED	SW	UNUSED					
1500		DDB_UNUSED	SW	UNUSED					
1501		DDB_UNUSED	SW	UNUSED					
1502		DDB_UNUSED	SW	UNUSED					
1503		DDB_UNUSED	SW	UNUSED					
1504	Quality VIP 1	DDB_VIP_QUALITY_1	SW	PFSO	GOOSE Virtual input 1 Quality bit	*	*	*	*
1505	Quality VIP 2	DDB_VIP_QUALITY_2	SW	PFSO	GOOSE Virtual input 2 Quality bit	*	*	*	*
1506	Quality VIP 3	DDB_VIP_QUALITY_3	SW	PFSO	GOOSE Virtual input 3 Quality bit	*	*	*	*
1507	Quality VIP 4	DDB_VIP_QUALITY_4	SW	PFSO	GOOSE Virtual input 4 Quality bit	*	*	*	*
1508	Quality VIP 5	DDB_VIP_QUALITY_5	SW	PFSO	GOOSE Virtual input 5 Quality bit	*	*	*	*
1509	Quality VIP 6	DDB_VIP_QUALITY_6	SW	PFSO	GOOSE Virtual input 6 Quality bit	*	*	*	*
1510	Quality VIP 7	DDB_VIP_QUALITY_7	SW	PFSO	GOOSE Virtual input 7 Quality bit	*	*	*	*
1511	Quality VIP 8	DDB_VIP_QUALITY_8	SW	PFSO	GOOSE Virtual input 8 Quality bit	*	*	*	*
1512	Quality VIP 9	DDB_VIP_QUALITY_9	SW	PFSO	GOOSE Virtual input 9 Quality bit	*	*	*	*
1513	Quality VIP 10	DDB_VIP_QUALITY_10	SW	PFSO	GOOSE Virtual input 10 Quality bit	*	*	*	*
1514	Quality VIP 11	DDB_VIP_QUALITY_11	SW	PFSO	GOOSE Virtual input 11 Quality bit	*	*	*	*
1515	Quality VIP 12	DDB_VIP_QUALITY_12	SW	PFSO	GOOSE Virtual input 12 Quality bit	*	*	*	*
1516	Quality VIP 13	DDB_VIP_QUALITY_13	SW	PFSO	GOOSE Virtual input 13 Quality bit	*	*	*	*
1517	Quality VIP 14	DDB_VIP_QUALITY_14	SW	PFSO	GOOSE Virtual input 14 Quality bit	*	*	*	*
1518	Quality VIP 15	DDB_VIP_QUALITY_15	SW	PFSO	GOOSE Virtual input 15 Quality bit	*	*	*	*
1519	Quality VIP 16	DDB_VIP_QUALITY_16	SW	PFSO	GOOSE Virtual input 16 Quality bit	*	*	*	*
1520	Quality VIP 17	DDB_VIP_QUALITY_17	SW	PFSO	GOOSE Virtual input 17 Quality bit	*	*	*	*
1521	Quality VIP 18	DDB_VIP_QUALITY_18	SW	PFSO	GOOSE Virtual input 18 Quality bit	*	*	*	*
1522	Quality VIP 19	DDB_VIP_QUALITY_19	SW	PFSO	GOOSE Virtual input 19 Quality bit	*	*	*	*
1523	Quality VIP 20	DDB_VIP_QUALITY_20	SW	PFSO	GOOSE Virtual input 20 Quality bit	*	*	*	*
1524	Quality VIP 21	DDB_VIP_QUALITY_21	SW	PFSO	GOOSE Virtual input 21 Quality bit	*	*	*	*
1525	Quality VIP 22	DDB_VIP_QUALITY_22	SW	PFSO	GOOSE Virtual input 22 Quality bit	*	*	*	*
1526	Quality VIP 23	DDB_VIP_QUALITY_23	SW	PFSO	GOOSE Virtual input 23 Quality bit	*	*	*	*
1527	Quality VIP 24	DDB_VIP_QUALITY_24	SW	PFSO	GOOSE Virtual input 24 Quality bit	*	*	*	*
1528	Quality VIP 25	DDB_VIP_QUALITY_25	SW	PFSO	GOOSE Virtual input 25 Quality bit	*	*	*	*
1529	Quality VIP 26	DDB_VIP_QUALITY_26	SW	PFSO	GOOSE Virtual input 26 Quality bit	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1530	Quality VIP 27	DDB_VIP_QUALITY_27	SW	PFSO	GOOSE Virtual input 27 Quality bit	*	*	*	*
1531	Quality VIP 28	DDB_VIP_QUALITY_28	SW	PFSO	GOOSE Virtual input 28 Quality bit	*	*	*	*
1532	Quality VIP 29	DDB_VIP_QUALITY_29	SW	PFSO	GOOSE Virtual input 29 Quality bit	*	*	*	*
1533	Quality VIP 30	DDB_VIP_QUALITY_30	SW	PFSO	GOOSE Virtual input 30 Quality bit	*	*	*	*
1534	Quality VIP 31	DDB_VIP_QUALITY_31	SW	PFSO	GOOSE Virtual input 31 Quality bit	*	*	*	*
1535	Quality VIP 32	DDB_VIP_QUALITY_32	SW	PFSO	GOOSE Virtual input 32 Quality bit	*	*	*	*
1536	Quality VIP 33	DDB_VIP_QUALITY_33	SW	PFSO	GOOSE Virtual input 33 Quality bit	*	*	*	*
1537	Quality VIP 34	DDB_VIP_QUALITY_34	SW	PFSO	GOOSE Virtual input 34 Quality bit	*	*	*	*
1538	Quality VIP 35	DDB_VIP_QUALITY_35	SW	PFSO	GOOSE Virtual input 35 Quality bit	*	*	*	*
1539	Quality VIP 36	DDB_VIP_QUALITY_36	SW	PFSO	GOOSE Virtual input 36 Quality bit	*	*	*	*
1540	Quality VIP 37	DDB_VIP_QUALITY_37	SW	PFSO	GOOSE Virtual input 37 Quality bit	*	*	*	*
1541	Quality VIP 38	DDB_VIP_QUALITY_38	SW	PFSO	GOOSE Virtual input 38 Quality bit	*	*	*	*
1542	Quality VIP 39	DDB_VIP_QUALITY_39	SW	PFSO	GOOSE Virtual input 39 Quality bit	*	*	*	*
1543	Quality VIP 40	DDB_VIP_QUALITY_40	SW	PFSO	GOOSE Virtual input 40 Quality bit	*	*	*	*
1544	Quality VIP 41	DDB_VIP_QUALITY_41	SW	PFSO	GOOSE Virtual input 41 Quality bit	*	*	*	*
1545	Quality VIP 42	DDB_VIP_QUALITY_42	SW	PFSO	GOOSE Virtual input 42 Quality bit	*	*	*	*
1546	Quality VIP 43	DDB_VIP_QUALITY_43	SW	PFSO	GOOSE Virtual input 43 Quality bit	*	*	*	*
1547	Quality VIP 44	DDB_VIP_QUALITY_44	SW	PFSO	GOOSE Virtual input 44 Quality bit	*	*	*	*
1548	Quality VIP 45	DDB_VIP_QUALITY_45	SW	PFSO	GOOSE Virtual input 45 Quality bit	*	*	*	*
1549	Quality VIP 46	DDB_VIP_QUALITY_46	SW	PFSO	GOOSE Virtual input 46 Quality bit	*	*	*	*
1550	Quality VIP 47	DDB_VIP_QUALITY_47	SW	PFSO	GOOSE Virtual input 47 Quality bit	*	*	*	*
1551	Quality VIP 48	DDB_VIP_QUALITY_48	SW	PFSO	GOOSE Virtual input 48 Quality bit	*	*	*	*
1552	Quality VIP 49	DDB_VIP_QUALITY_49	SW	PFSO	GOOSE Virtual input 49 Quality bit	*	*	*	*
1553	Quality VIP 50	DDB_VIP_QUALITY_50	SW	PFSO	GOOSE Virtual input 50 Quality bit	*	*	*	*
1554	Quality VIP 51	DDB_VIP_QUALITY_51	SW	PFSO	GOOSE Virtual input 51 Quality bit	*	*	*	*
1555	Quality VIP 52	DDB_VIP_QUALITY_52	SW	PFSO	GOOSE Virtual input 52 Quality bit	*	*	*	*
1556	Quality VIP 53	DDB_VIP_QUALITY_53	SW	PFSO	GOOSE Virtual input 53 Quality bit	*	*	*	*
1557	Quality VIP 54	DDB_VIP_QUALITY_54	SW	PFSO	GOOSE Virtual input 54 Quality bit	*	*	*	*
1558	Quality VIP 55	DDB_VIP_QUALITY_55	SW	PFSO	GOOSE Virtual input 55 Quality bit	*	*	*	*
1559	Quality VIP 56	DDB_VIP_QUALITY_56	SW	PFSO	GOOSE Virtual input 56 Quality bit	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1560	Quality VIP 57	DDB_VIP_QUALITY_57	SW	PFSO	GOOSE Virtual input 57 Quality bit	*	*	*	*
1561	Quality VIP 58	DDB_VIP_QUALITY_58	SW	PFSO	GOOSE Virtual input 58 Quality bit	*	*	*	*
1562	Quality VIP 59	DDB_VIP_QUALITY_59	SW	PFSO	GOOSE Virtual input 59 Quality bit	*	*	*	*
1563	Quality VIP 60	DDB_VIP_QUALITY_60	SW	PFSO	GOOSE Virtual input 60 Quality bit	*	*	*	*
1564	Quality VIP 61	DDB_VIP_QUALITY_61	SW	PFSO	GOOSE Virtual input 61 Quality bit	*	*	*	*
1565	Quality VIP 62	DDB_VIP_QUALITY_62	SW	PFSO	GOOSE Virtual input 62 Quality bit	*	*	*	*
1566	Quality VIP 63	DDB_VIP_QUALITY_63	SW	PFSO	GOOSE Virtual input 63 Quality bit	*	*	*	*
1567	Quality VIP 64	DDB_VIP_QUALITY_64	SW	PFSO	GOOSE Virtual input 64 Quality bit	*	*	*	*
1568	ETH Link 1 Fail	DDB_NIC_LINK_1_FAIL	SW	PFSO	Network Interface Card link 1 fail indication	*	*	*	*
1569	ETH Link 2 Fail	DDB_NIC_LINK_2_FAIL	SW	PFSO	Network Interface Card link 2 fail indication	*	*	*	*
1570	ETH Link 3 Fail	DDB_NIC_LINK_3_FAIL	SW	PFSO	Network Interface Card link 3 fail indication	*	*	*	*
1571		DDB_UNUSED	SW	UNUSED					
1572		DDB_UNUSED	SW	UNUSED					
1573		DDB_UNUSED	SW	UNUSED					
1574		DDB_UNUSED	SW	UNUSED					
1575		DDB_UNUSED	SW	UNUSED					
1576		DDB_UNUSED	SW	UNUSED					
1577		DDB_UNUSED	SW	UNUSED					
1578		DDB_UNUSED	SW	UNUSED					
1579		DDB_UNUSED	SW	UNUSED					
1580		DDB_UNUSED	SW	UNUSED					
1581		DDB_UNUSED	SW	UNUSED					
1582		DDB_UNUSED	SW	UNUSED					
1583		DDB_UNUSED	SW	UNUSED					
1584		DDB_UNUSED	SW	UNUSED					
1585		DDB_UNUSED	SW	UNUSED					
1586		DDB_UNUSED	SW	UNUSED					
1587		DDB_UNUSED	SW	UNUSED					
1588		DDB_UNUSED	SW	UNUSED					
1589		DDB_UNUSED	SW	UNUSED					
1590		DDB_UNUSED	SW	UNUSED					
1591		DDB_UNUSED	SW	UNUSED					
1592		DDB_UNUSED	SW	UNUSED					
1593		DDB_UNUSED	SW	UNUSED					
1594		DDB_UNUSED	SW	UNUSED					
1595		DDB_UNUSED	SW	UNUSED					
1596		DDB_UNUSED	SW	UNUSED					
1597		DDB_UNUSED	SW	UNUSED					
1598		DDB_UNUSED	SW	UNUSED					
1599		DDB_UNUSED	SW	UNUSED					
1600	PubPres VIP 1	DDB_VIP_PUB_PRES_1	SW	PFSO	GOOSE Virtual input 1 publisher bit	*	*	*	*
1601	PubPres VIP 2	DDB_VIP_PUB_PRES_2	SW	PFSO	GOOSE Virtual input 2 publisher bit	*	*	*	*
1602	PubPres VIP 3	DDB_VIP_PUB_PRES_3	SW	PFSO	GOOSE Virtual input 3 publisher bit	*	*	*	*
1603	PubPres VIP 4	DDB_VIP_PUB_PRES_4	SW	PFSO	GOOSE Virtual input 4 publisher bit	*	*	*	*
1604	PubPres VIP 5	DDB_VIP_PUB_PRES_5	SW	PFSO	GOOSE Virtual input 5 publisher bit	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1605	PubPres VIP 6	DDB_VIP_PUB_PRES_6	SW	PFSO	GOOSE Virtual input 6 publisher bit	*	*	*	*
1606	PubPres VIP 7	DDB_VIP_PUB_PRES_7	SW	PFSO	GOOSE Virtual input 7 publisher bit	*	*	*	*
1607	PubPres VIP 8	DDB_VIP_PUB_PRES_8	SW	PFSO	GOOSE Virtual input 8 publisher bit	*	*	*	*
1608	PubPres VIP 9	DDB_VIP_PUB_PRES_9	SW	PFSO	GOOSE Virtual input 9 publisher bit	*	*	*	*
1609	PubPres VIP 10	DDB_VIP_PUB_PRES_10	SW	PFSO	GOOSE Virtual input 10 publisher bit	*	*	*	*
1610	PubPres VIP 11	DDB_VIP_PUB_PRES_11	SW	PFSO	GOOSE Virtual input 11 publisher bit	*	*	*	*
1611	PubPres VIP 12	DDB_VIP_PUB_PRES_12	SW	PFSO	GOOSE Virtual input 12 publisher bit	*	*	*	*
1612	PubPres VIP 13	DDB_VIP_PUB_PRES_13	SW	PFSO	GOOSE Virtual input 13 publisher bit	*	*	*	*
1613	PubPres VIP 14	DDB_VIP_PUB_PRES_14	SW	PFSO	GOOSE Virtual input 14 publisher bit	*	*	*	*
1614	PubPres VIP 15	DDB_VIP_PUB_PRES_15	SW	PFSO	GOOSE Virtual input 15 publisher bit	*	*	*	*
1615	PubPres VIP 16	DDB_VIP_PUB_PRES_16	SW	PFSO	GOOSE Virtual input 16 publisher bit	*	*	*	*
1616	PubPres VIP 17	DDB_VIP_PUB_PRES_17	SW	PFSO	GOOSE Virtual input 17 publisher bit	*	*	*	*
1617	PubPres VIP 18	DDB_VIP_PUB_PRES_18	SW	PFSO	GOOSE Virtual input 18 publisher bit	*	*	*	*
1618	PubPres VIP 19	DDB_VIP_PUB_PRES_19	SW	PFSO	GOOSE Virtual input 19 publisher bit	*	*	*	*
1619	PubPres VIP 20	DDB_VIP_PUB_PRES_20	SW	PFSO	GOOSE Virtual input 20 publisher bit	*	*	*	*
1620	PubPres VIP 21	DDB_VIP_PUB_PRES_21	SW	PFSO	GOOSE Virtual input 21 publisher bit	*	*	*	*
1621	PubPres VIP 22	DDB_VIP_PUB_PRES_22	SW	PFSO	GOOSE Virtual input 22 publisher bit	*	*	*	*
1622	PubPres VIP 23	DDB_VIP_PUB_PRES_23	SW	PFSO	GOOSE Virtual input 23 publisher bit	*	*	*	*
1623	PubPres VIP 24	DDB_VIP_PUB_PRES_24	SW	PFSO	GOOSE Virtual input 24 publisher bit	*	*	*	*
1624	PubPres VIP 25	DDB_VIP_PUB_PRES_25	SW	PFSO	GOOSE Virtual input 25 publisher bit	*	*	*	*
1625	PubPres VIP 26	DDB_VIP_PUB_PRES_26	SW	PFSO	GOOSE Virtual input 26 publisher bit	*	*	*	*
1626	PubPres VIP 27	DDB_VIP_PUB_PRES_27	SW	PFSO	GOOSE Virtual input 27 publisher bit	*	*	*	*
1627	PubPres VIP 28	DDB_VIP_PUB_PRES_28	SW	PFSO	GOOSE Virtual input 28 publisher bit	*	*	*	*
1628	PubPres VIP 29	DDB_VIP_PUB_PRES_29	SW	PFSO	GOOSE Virtual input 29 publisher bit	*	*	*	*
1629	PubPres VIP 30	DDB_VIP_PUB_PRES_30	SW	PFSO	GOOSE Virtual input 30 publisher bit	*	*	*	*
1630	PubPres VIP 31	DDB_VIP_PUB_PRES_31	SW	PFSO	GOOSE Virtual input 31 publisher bit	*	*	*	*
1631	PubPres VIP 32	DDB_VIP_PUB_PRES_32	SW	PFSO	GOOSE Virtual input 32 publisher bit	*	*	*	*
1632	PubPres VIP 33	DDB_VIP_PUB_PRES_33	SW	PFSO	GOOSE Virtual input 33 publisher bit	*	*	*	*
1633	PubPres VIP 34	DDB_VIP_PUB_PRES_34	SW	PFSO	GOOSE Virtual input 34 publisher bit	*	*	*	*
1634	PubPres VIP 35	DDB_VIP_PUB_PRES_35	SW	PFSO	GOOSE Virtual input 35 publisher bit	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1635	PubPres VIP 36	DDB_VIP_PUB_PRES_36	SW	PFSO	GOOSE Virtual input 36 publisher bit	*	*	*	*
1636	PubPres VIP 37	DDB_VIP_PUB_PRES_37	SW	PFSO	GOOSE Virtual input 37 publisher bit	*	*	*	*
1637	PubPres VIP 38	DDB_VIP_PUB_PRES_38	SW	PFSO	GOOSE Virtual input 38 publisher bit	*	*	*	*
1638	PubPres VIP 39	DDB_VIP_PUB_PRES_39	SW	PFSO	GOOSE Virtual input 39 publisher bit	*	*	*	*
1639	PubPres VIP 40	DDB_VIP_PUB_PRES_40	SW	PFSO	GOOSE Virtual input 40 publisher bit	*	*	*	*
1640	PubPres VIP 41	DDB_VIP_PUB_PRES_41	SW	PFSO	GOOSE Virtual input 41 publisher bit	*	*	*	*
1641	PubPres VIP 42	DDB_VIP_PUB_PRES_42	SW	PFSO	GOOSE Virtual input 42 publisher bit	*	*	*	*
1642	PubPres VIP 43	DDB_VIP_PUB_PRES_43	SW	PFSO	GOOSE Virtual input 43 publisher bit	*	*	*	*
1643	PubPres VIP 44	DDB_VIP_PUB_PRES_44	SW	PFSO	GOOSE Virtual input 44 publisher bit	*	*	*	*
1644	PubPres VIP 45	DDB_VIP_PUB_PRES_45	SW	PFSO	GOOSE Virtual input 45 publisher bit	*	*	*	*
1645	PubPres VIP 46	DDB_VIP_PUB_PRES_46	SW	PFSO	GOOSE Virtual input 46 publisher bit	*	*	*	*
1646	PubPres VIP 47	DDB_VIP_PUB_PRES_47	SW	PFSO	GOOSE Virtual input 47 publisher bit	*	*	*	*
1647	PubPres VIP 48	DDB_VIP_PUB_PRES_48	SW	PFSO	GOOSE Virtual input 48 publisher bit	*	*	*	*
1648	PubPres VIP 49	DDB_VIP_PUB_PRES_49	SW	PFSO	GOOSE Virtual input 49 publisher bit	*	*	*	*
1649	PubPres VIP 50	DDB_VIP_PUB_PRES_50	SW	PFSO	GOOSE Virtual input 50 publisher bit	*	*	*	*
1650	PubPres VIP 51	DDB_VIP_PUB_PRES_51	SW	PFSO	GOOSE Virtual input 51 publisher bit	*	*	*	*
1651	PubPres VIP 52	DDB_VIP_PUB_PRES_52	SW	PFSO	GOOSE Virtual input 52 publisher bit	*	*	*	*
1652	PubPres VIP 53	DDB_VIP_PUB_PRES_53	SW	PFSO	GOOSE Virtual input 53 publisher bit	*	*	*	*
1653	PubPres VIP 54	DDB_VIP_PUB_PRES_54	SW	PFSO	GOOSE Virtual input 54 publisher bit	*	*	*	*
1654	PubPres VIP 55	DDB_VIP_PUB_PRES_55	SW	PFSO	GOOSE Virtual input 55 publisher bit	*	*	*	*
1655	PubPres VIP 56	DDB_VIP_PUB_PRES_56	SW	PFSO	GOOSE Virtual input 56 publisher bit	*	*	*	*
1656	PubPres VIP 57	DDB_VIP_PUB_PRES_57	SW	PFSO	GOOSE Virtual input 57 publisher bit	*	*	*	*
1657	PubPres VIP 58	DDB_VIP_PUB_PRES_58	SW	PFSO	GOOSE Virtual input 58 publisher bit	*	*	*	*
1658	PubPres VIP 59	DDB_VIP_PUB_PRES_59	SW	PFSO	GOOSE Virtual input 59 publisher bit	*	*	*	*
1659	PubPres VIP 60	DDB_VIP_PUB_PRES_60	SW	PFSO	GOOSE Virtual input 60 publisher bit	*	*	*	*
1660	PubPres VIP 61	DDB_VIP_PUB_PRES_61	SW	PFSO	GOOSE Virtual input 61 publisher bit	*	*	*	*
1661	PubPres VIP 62	DDB_VIP_PUB_PRES_62	SW	PFSO	GOOSE Virtual input 62 publisher bit	*	*	*	*
1662	PubPres VIP 63	DDB_VIP_PUB_PRES_63	SW	PFSO	GOOSE Virtual input 63 publisher bit	*	*	*	*
1663	PubPres VIP 64	DDB_VIP_PUB_PRES_64	SW	PFSO	GOOSE Virtual input 64 publisher bit	*	*	*	*
1664		DDB_UNUSED	SW	UNUSED					
1665		DDB_UNUSED	SW	UNUSED					
1666		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1667		DDB_UNUSED	SW	UNUSED					
1668		DDB_UNUSED	SW	UNUSED					
1669		DDB_UNUSED	SW	UNUSED					
1670		DDB_UNUSED	SW	UNUSED					
1671		DDB_UNUSED	SW	UNUSED					
1672		DDB_UNUSED	SW	UNUSED					
1673		DDB_UNUSED	SW	UNUSED					
1674		DDB_UNUSED	SW	UNUSED					
1675		DDB_UNUSED	SW	UNUSED					
1676		DDB_UNUSED	SW	UNUSED					
1677		DDB_UNUSED	SW	UNUSED					
1678		DDB_UNUSED	SW	UNUSED					
1679		DDB_UNUSED	SW	UNUSED					
1680		DDB_UNUSED	SW	UNUSED					
1681		DDB_UNUSED	SW	UNUSED					
1682		DDB_UNUSED	SW	UNUSED					
1683		DDB_UNUSED	SW	UNUSED					
1684		DDB_UNUSED	SW	UNUSED					
1685		DDB_UNUSED	SW	UNUSED					
1686		DDB_UNUSED	SW	UNUSED					
1687		DDB_UNUSED	SW	UNUSED					
1688		DDB_UNUSED	SW	UNUSED					
1689		DDB_UNUSED	SW	UNUSED					
1690		DDB_UNUSED	SW	UNUSED					
1691		DDB_UNUSED	SW	UNUSED					
1692		DDB_UNUSED	SW	UNUSED					
1693		DDB_UNUSED	SW	UNUSED					
1694		DDB_UNUSED	SW	UNUSED					
1695		DDB_UNUSED	SW	UNUSED					
1696	Virtual Output01	DDB_GOOSEOUT_1	PSL	GOOSEOUT	Virtual Output 01	*	*	*	*
1697	Virtual Output02	DDB_GOOSEOUT_2	PSL	GOOSEOUT	Virtual Output 02	*	*	*	*
1698	Virtual Output03	DDB_GOOSEOUT_3	PSL	GOOSEOUT	Virtual Output 03	*	*	*	*
1699	Virtual Output04	DDB_GOOSEOUT_4	PSL	GOOSEOUT	Virtual Output 04	*	*	*	*
1700	Virtual Output05	DDB_GOOSEOUT_5	PSL	GOOSEOUT	Virtual Output 05	*	*	*	*
1701	Virtual Output06	DDB_GOOSEOUT_6	PSL	GOOSEOUT	Virtual Output 06	*	*	*	*
1702	Virtual Output07	DDB_GOOSEOUT_7	PSL	GOOSEOUT	Virtual Output 07	*	*	*	*
1703	Virtual Output08	DDB_GOOSEOUT_8	PSL	GOOSEOUT	Virtual Output 08	*	*	*	*
1704	Virtual Output09	DDB_GOOSEOUT_9	PSL	GOOSEOUT	Virtual Output 09	*	*	*	*
1705	Virtual Output10	DDB_GOOSEOUT_10	PSL	GOOSEOUT	Virtual Output 10	*	*	*	*
1706	Virtual Output11	DDB_GOOSEOUT_11	PSL	GOOSEOUT	Virtual Output 11	*	*	*	*
1707	Virtual Output12	DDB_GOOSEOUT_12	PSL	GOOSEOUT	Virtual Output 12	*	*	*	*
1708	Virtual Output13	DDB_GOOSEOUT_13	PSL	GOOSEOUT	Virtual Output 13	*	*	*	*
1709	Virtual Output14	DDB_GOOSEOUT_14	PSL	GOOSEOUT	Virtual Output 14	*	*	*	*
1710	Virtual Output15	DDB_GOOSEOUT_15	PSL	GOOSEOUT	Virtual Output 15	*	*	*	*
1711	Virtual Output16	DDB_GOOSEOUT_16	PSL	GOOSEOUT	Virtual Output 16	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1712	Virtual Output17	DDB_GOOSEOUT_17	PSL	GOOSEOUT	Virtual Output 17	*	*	*	*
1713	Virtual Output18	DDB_GOOSEOUT_18	PSL	GOOSEOUT	Virtual Output 18	*	*	*	*
1714	Virtual Output19	DDB_GOOSEOUT_19	PSL	GOOSEOUT	Virtual Output 19	*	*	*	*
1715	Virtual Output20	DDB_GOOSEOUT_20	PSL	GOOSEOUT	Virtual Output 20	*	*	*	*
1716	Virtual Output21	DDB_GOOSEOUT_21	PSL	GOOSEOUT	Virtual Output 21	*	*	*	*
1717	Virtual Output22	DDB_GOOSEOUT_22	PSL	GOOSEOUT	Virtual Output 22	*	*	*	*
1718	Virtual Output23	DDB_GOOSEOUT_23	PSL	GOOSEOUT	Virtual Output 23	*	*	*	*
1719	Virtual Output24	DDB_GOOSEOUT_24	PSL	GOOSEOUT	Virtual Output 24	*	*	*	*
1720	Virtual Output25	DDB_GOOSEOUT_25	PSL	GOOSEOUT	Virtual Output 25	*	*	*	*
1721	Virtual Output26	DDB_GOOSEOUT_26	PSL	GOOSEOUT	Virtual Output 26	*	*	*	*
1722	Virtual Output27	DDB_GOOSEOUT_27	PSL	GOOSEOUT	Virtual Output 27	*	*	*	*
1723	Virtual Output28	DDB_GOOSEOUT_28	PSL	GOOSEOUT	Virtual Output 28	*	*	*	*
1724	Virtual Output29	DDB_GOOSEOUT_29	PSL	GOOSEOUT	Virtual Output 29	*	*	*	*
1725	Virtual Output30	DDB_GOOSEOUT_30	PSL	GOOSEOUT	Virtual Output 30	*	*	*	*
1726	Virtual Output31	DDB_GOOSEOUT_31	PSL	GOOSEOUT	Virtual Output 31	*	*	*	*
1727	Virtual Output32	DDB_GOOSEOUT_32	PSL	GOOSEOUT	Virtual Output 32	*	*	*	*
1728	Virtual Output33	DDB_GOOSEOUT_33	PSL	GOOSEOUT	Virtual Output 33	*	*	*	*
1729	Virtual Output34	DDB_GOOSEOUT_34	PSL	GOOSEOUT	Virtual Output 34	*	*	*	*
1730	Virtual Output35	DDB_GOOSEOUT_35	PSL	GOOSEOUT	Virtual Output 35	*	*	*	*
1731	Virtual Output36	DDB_GOOSEOUT_36	PSL	GOOSEOUT	Virtual Output 36	*	*	*	*
1732	Virtual Output37	DDB_GOOSEOUT_37	PSL	GOOSEOUT	Virtual Output 37	*	*	*	*
1733	Virtual Output38	DDB_GOOSEOUT_38	PSL	GOOSEOUT	Virtual Output 38	*	*	*	*
1734	Virtual Output39	DDB_GOOSEOUT_39	PSL	GOOSEOUT	Virtual Output 39	*	*	*	*
1735	Virtual Output40	DDB_GOOSEOUT_40	PSL	GOOSEOUT	Virtual Output 40	*	*	*	*
1736	Virtual Output41	DDB_GOOSEOUT_41	PSL	GOOSEOUT	Virtual Output 41	*	*	*	*
1737	Virtual Output42	DDB_GOOSEOUT_42	PSL	GOOSEOUT	Virtual Output 42	*	*	*	*
1738	Virtual Output43	DDB_GOOSEOUT_43	PSL	GOOSEOUT	Virtual Output 43	*	*	*	*
1739	Virtual Output44	DDB_GOOSEOUT_44	PSL	GOOSEOUT	Virtual Output 44	*	*	*	*
1740	Virtual Output45	DDB_GOOSEOUT_45	PSL	GOOSEOUT	Virtual Output 45	*	*	*	*
1741	Virtual Output46	DDB_GOOSEOUT_46	PSL	GOOSEOUT	Virtual Output 46	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1742	Virtual Output47	DDB_GOOSEOUT_47	PSL	GOOSEOUT	Virtual Output 47	*	*	*	*
1743	Virtual Output48	DDB_GOOSEOUT_48	PSL	GOOSEOUT	Virtual Output 48	*	*	*	*
1744	Virtual Output49	DDB_GOOSEOUT_49	PSL	GOOSEOUT	Virtual Output 49	*	*	*	*
1745	Virtual Output50	DDB_GOOSEOUT_50	PSL	GOOSEOUT	Virtual Output 50	*	*	*	*
1746	Virtual Output51	DDB_GOOSEOUT_51	PSL	GOOSEOUT	Virtual Output 51	*	*	*	*
1747	Virtual Output52	DDB_GOOSEOUT_52	PSL	GOOSEOUT	Virtual Output 52	*	*	*	*
1748	Virtual Output53	DDB_GOOSEOUT_53	PSL	GOOSEOUT	Virtual Output 53	*	*	*	*
1749	Virtual Output54	DDB_GOOSEOUT_54	PSL	GOOSEOUT	Virtual Output 54	*	*	*	*
1750	Virtual Output55	DDB_GOOSEOUT_55	PSL	GOOSEOUT	Virtual Output 55	*	*	*	*
1751	Virtual Output56	DDB_GOOSEOUT_56	PSL	GOOSEOUT	Virtual Output 56	*	*	*	*
1752	Virtual Output57	DDB_GOOSEOUT_57	PSL	GOOSEOUT	Virtual Output 57	*	*	*	*
1753	Virtual Output58	DDB_GOOSEOUT_58	PSL	GOOSEOUT	Virtual Output 58	*	*	*	*
1754	Virtual Output59	DDB_GOOSEOUT_59	PSL	GOOSEOUT	Virtual Output 59	*	*	*	*
1755	Virtual Output60	DDB_GOOSEOUT_60	PSL	GOOSEOUT	Virtual Output 60	*	*	*	*
1756	Virtual Output61	DDB_GOOSEOUT_61	PSL	GOOSEOUT	Virtual Output 61	*	*	*	*
1757	Virtual Output62	DDB_GOOSEOUT_62	PSL	GOOSEOUT	Virtual Output 62	*	*	*	*
1758	Virtual Output63	DDB_GOOSEOUT_63	PSL	GOOSEOUT	Virtual Output 63	*	*	*	*
1759	Virtual Output64	DDB_GOOSEOUT_64	PSL	GOOSEOUT	Virtual Output 64	*	*	*	*
1760		DDB_UNUSED	SW	UNUSED					
1761		DDB_UNUSED	SW	UNUSED					
1762		DDB_UNUSED	SW	UNUSED					
1763		DDB_UNUSED	SW	UNUSED					
1764		DDB_UNUSED	SW	UNUSED					
1765		DDB_UNUSED	SW	UNUSED					
1766		DDB_UNUSED	SW	UNUSED					
1767		DDB_UNUSED	SW	UNUSED					
1768		DDB_UNUSED	SW	UNUSED					
1769		DDB_UNUSED	SW	UNUSED					
1770		DDB_UNUSED	SW	UNUSED					
1771		DDB_UNUSED	SW	UNUSED					
1772		DDB_UNUSED	SW	UNUSED					
1773		DDB_UNUSED	SW	UNUSED					
1774		DDB_UNUSED	SW	UNUSED					
1775		DDB_UNUSED	SW	UNUSED					
1776		DDB_UNUSED	SW	UNUSED					
1777		DDB_UNUSED	SW	UNUSED					
1778		DDB_UNUSED	SW	UNUSED					
1779		DDB_UNUSED	SW	UNUSED					
1780		DDB_UNUSED	SW	UNUSED					
1781		DDB_UNUSED	SW	UNUSED					
1782		DDB_UNUSED	SW	UNUSED					
1783		DDB_UNUSED	SW	UNUSED					
1784		DDB_UNUSED	SW	UNUSED					

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1785		DDB_UNUSED	SW	UNUSED					
1786		DDB_UNUSED	SW	UNUSED					
1787		DDB_UNUSED	SW	UNUSED					
1788		DDB_UNUSED	SW	UNUSED					
1789		DDB_UNUSED	SW	UNUSED					
1790		DDB_UNUSED	SW	UNUSED					
1791		DDB_UNUSED	SW	UNUSED					
1792	PSL Int. 1	DDB_PSLINT_1	PSL	PSLINT	PSL Internal connection	*	*	*	*
1793	PSL Int. 2	DDB_PSLINT_2	PSL	PSLINT	PSL Internal connection	*	*	*	*
1794	PSL Int. 3	DDB_PSLINT_3	PSL	PSLINT	PSL Internal connection	*	*	*	*
1795	PSL Int. 4	DDB_PSLINT_4	PSL	PSLINT	PSL Internal connection	*	*	*	*
1796	PSL Int. 5	DDB_PSLINT_5	PSL	PSLINT	PSL Internal connection	*	*	*	*
1797	PSL Int. 6	DDB_PSLINT_6	PSL	PSLINT	PSL Internal connection	*	*	*	*
1798	PSL Int. 7	DDB_PSLINT_7	PSL	PSLINT	PSL Internal connection	*	*	*	*
1799	PSL Int. 8	DDB_PSLINT_8	PSL	PSLINT	PSL Internal connection	*	*	*	*
1800	PSL Int. 9	DDB_PSLINT_9	PSL	PSLINT	PSL Internal connection	*	*	*	*
1801	PSL Int. 10	DDB_PSLINT_10	PSL	PSLINT	PSL Internal connection	*	*	*	*
1802	PSL Int. 11	DDB_PSLINT_11	PSL	PSLINT	PSL Internal connection	*	*	*	*
1803	PSL Int. 12	DDB_PSLINT_12	PSL	PSLINT	PSL Internal connection	*	*	*	*
1804	PSL Int. 13	DDB_PSLINT_13	PSL	PSLINT	PSL Internal connection	*	*	*	*
1805	PSL Int. 14	DDB_PSLINT_14	PSL	PSLINT	PSL Internal connection	*	*	*	*
1806	PSL Int. 15	DDB_PSLINT_15	PSL	PSLINT	PSL Internal connection	*	*	*	*
1807	PSL Int. 16	DDB_PSLINT_16	PSL	PSLINT	PSL Internal connection	*	*	*	*
1808	PSL Int. 17	DDB_PSLINT_17	PSL	PSLINT	PSL Internal connection	*	*	*	*
1809	PSL Int. 18	DDB_PSLINT_18	PSL	PSLINT	PSL Internal connection	*	*	*	*
1810	PSL Int. 19	DDB_PSLINT_19	PSL	PSLINT	PSL Internal connection	*	*	*	*
1811	PSL Int. 20	DDB_PSLINT_20	PSL	PSLINT	PSL Internal connection	*	*	*	*
1812	PSL Int. 21	DDB_PSLINT_21	PSL	PSLINT	PSL Internal connection	*	*	*	*
1813	PSL Int. 22	DDB_PSLINT_22	PSL	PSLINT	PSL Internal connection	*	*	*	*
1814	PSL Int. 23	DDB_PSLINT_23	PSL	PSLINT	PSL Internal connection	*	*	*	*
1815	PSL Int. 24	DDB_PSLINT_24	PSL	PSLINT	PSL Internal connection	*	*	*	*
1816	PSL Int. 25	DDB_PSLINT_25	PSL	PSLINT	PSL Internal connection	*	*	*	*
1817	PSL Int. 26	DDB_PSLINT_26	PSL	PSLINT	PSL Internal connection	*	*	*	*
1818	PSL Int. 27	DDB_PSLINT_27	PSL	PSLINT	PSL Internal connection	*	*	*	*
1819	PSL Int. 28	DDB_PSLINT_28	PSL	PSLINT	PSL Internal connection	*	*	*	*
1820	PSL Int. 29	DDB_PSLINT_29	PSL	PSLINT	PSL Internal connection	*	*	*	*
1821	PSL Int. 30	DDB_PSLINT_30	PSL	PSLINT	PSL Internal connection	*	*	*	*
1822	PSL Int. 31	DDB_PSLINT_31	PSL	PSLINT	PSL Internal connection	*	*	*	*
1823	PSL Int. 32	DDB_PSLINT_32	PSL	PSLINT	PSL Internal connection	*	*	*	*
1824	PSL Int. 33	DDB_PSLINT_33	PSL	PSLINT	PSL Internal connection	*	*	*	*
1825	PSL Int. 34	DDB_PSLINT_34	PSL	PSLINT	PSL Internal connection	*	*	*	*
1826	PSL Int. 35	DDB_PSLINT_35	PSL	PSLINT	PSL Internal connection	*	*	*	*
1827	PSL Int. 36	DDB_PSLINT_36	PSL	PSLINT	PSL Internal connection	*	*	*	*
1828	PSL Int. 37	DDB_PSLINT_37	PSL	PSLINT	PSL Internal connection	*	*	*	*
1829	PSL Int. 38	DDB_PSLINT_38	PSL	PSLINT	PSL Internal connection	*	*	*	*
1830	PSL Int. 39	DDB_PSLINT_39	PSL	PSLINT	PSL Internal connection	*	*	*	*
1831	PSL Int. 40	DDB_PSLINT_40	PSL	PSLINT	PSL Internal connection	*	*	*	*
1832	PSL Int. 41	DDB_PSLINT_41	PSL	PSLINT	PSL Internal connection	*	*	*	*
1833	PSL Int. 42	DDB_PSLINT_42	PSL	PSLINT	PSL Internal connection	*	*	*	*
1834	PSL Int. 43	DDB_PSLINT_43	PSL	PSLINT	PSL Internal connection	*	*	*	*
1835	PSL Int. 44	DDB_PSLINT_44	PSL	PSLINT	PSL Internal connection	*	*	*	*
1836	PSL Int. 45	DDB_PSLINT_45	PSL	PSLINT	PSL Internal connection	*	*	*	*
1837	PSL Int. 46	DDB_PSLINT_46	PSL	PSLINT	PSL Internal connection	*	*	*	*
1838	PSL Int. 47	DDB_PSLINT_47	PSL	PSLINT	PSL Internal connection	*	*	*	*
1839	PSL Int. 48	DDB_PSLINT_48	PSL	PSLINT	PSL Internal connection	*	*	*	*
1840	PSL Int. 49	DDB_PSLINT_49	PSL	PSLINT	PSL Internal connection	*	*	*	*
1841	PSL Int. 50	DDB_PSLINT_50	PSL	PSLINT	PSL Internal connection	*	*	*	*
1842	PSL Int. 51	DDB_PSLINT_51	PSL	PSLINT	PSL Internal connection	*	*	*	*
1843	PSL Int. 52	DDB_PSLINT_52	PSL	PSLINT	PSL Internal connection	*	*	*	*
1844	PSL Int. 53	DDB_PSLINT_53	PSL	PSLINT	PSL Internal connection	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1845	PSL Int. 54	DDB_PSLINT_54	PSL	PSLINT	PSL Internal connection	*	*	*	*
1846	PSL Int. 55	DDB_PSLINT_55	PSL	PSLINT	PSL Internal connection	*	*	*	*
1847	PSL Int. 56	DDB_PSLINT_56	PSL	PSLINT	PSL Internal connection	*	*	*	*
1848	PSL Int. 57	DDB_PSLINT_57	PSL	PSLINT	PSL Internal connection	*	*	*	*
1849	PSL Int. 58	DDB_PSLINT_58	PSL	PSLINT	PSL Internal connection	*	*	*	*
1850	PSL Int. 59	DDB_PSLINT_59	PSL	PSLINT	PSL Internal connection	*	*	*	*
1851	PSL Int. 60	DDB_PSLINT_60	PSL	PSLINT	PSL Internal connection	*	*	*	*
1852	PSL Int. 61	DDB_PSLINT_61	PSL	PSLINT	PSL Internal connection	*	*	*	*
1853	PSL Int. 62	DDB_PSLINT_62	PSL	PSLINT	PSL Internal connection	*	*	*	*
1854	PSL Int. 63	DDB_PSLINT_63	PSL	PSLINT	PSL Internal connection	*	*	*	*
1855	PSL Int. 64	DDB_PSLINT_64	PSL	PSLINT	PSL Internal connection	*	*	*	*
1856	PSL Int. 65	DDB_PSLINT_65	PSL	PSLINT	PSL Internal connection	*	*	*	*
1857	PSL Int. 66	DDB_PSLINT_66	PSL	PSLINT	PSL Internal connection	*	*	*	*
1858	PSL Int. 67	DDB_PSLINT_67	PSL	PSLINT	PSL Internal connection	*	*	*	*
1859	PSL Int. 68	DDB_PSLINT_68	PSL	PSLINT	PSL Internal connection	*	*	*	*
1860	PSL Int. 69	DDB_PSLINT_69	PSL	PSLINT	PSL Internal connection	*	*	*	*
1861	PSL Int. 70	DDB_PSLINT_70	PSL	PSLINT	PSL Internal connection	*	*	*	*
1862	PSL Int. 71	DDB_PSLINT_71	PSL	PSLINT	PSL Internal connection	*	*	*	*
1863	PSL Int. 72	DDB_PSLINT_72	PSL	PSLINT	PSL Internal connection	*	*	*	*
1864	PSL Int. 73	DDB_PSLINT_73	PSL	PSLINT	PSL Internal connection	*	*	*	*
1865	PSL Int. 74	DDB_PSLINT_74	PSL	PSLINT	PSL Internal connection	*	*	*	*
1866	PSL Int. 75	DDB_PSLINT_75	PSL	PSLINT	PSL Internal connection	*	*	*	*
1867	PSL Int. 76	DDB_PSLINT_76	PSL	PSLINT	PSL Internal connection	*	*	*	*
1868	PSL Int. 77	DDB_PSLINT_77	PSL	PSLINT	PSL Internal connection	*	*	*	*
1869	PSL Int. 78	DDB_PSLINT_78	PSL	PSLINT	PSL Internal connection	*	*	*	*
1870	PSL Int. 79	DDB_PSLINT_79	PSL	PSLINT	PSL Internal connection	*	*	*	*
1871	PSL Int. 80	DDB_PSLINT_80	PSL	PSLINT	PSL Internal connection	*	*	*	*
1872	PSL Int. 81	DDB_PSLINT_81	PSL	PSLINT	PSL Internal connection	*	*	*	*
1873	PSL Int. 82	DDB_PSLINT_82	PSL	PSLINT	PSL Internal connection	*	*	*	*
1874	PSL Int. 83	DDB_PSLINT_83	PSL	PSLINT	PSL Internal connection	*	*	*	*
1875	PSL Int. 84	DDB_PSLINT_84	PSL	PSLINT	PSL Internal connection	*	*	*	*
1876	PSL Int. 85	DDB_PSLINT_85	PSL	PSLINT	PSL Internal connection	*	*	*	*
1877	PSL Int. 86	DDB_PSLINT_86	PSL	PSLINT	PSL Internal connection	*	*	*	*
1878	PSL Int. 87	DDB_PSLINT_87	PSL	PSLINT	PSL Internal connection	*	*	*	*
1879	PSL Int. 88	DDB_PSLINT_88	PSL	PSLINT	PSL Internal connection	*	*	*	*
1880	PSL Int. 89	DDB_PSLINT_89	PSL	PSLINT	PSL Internal connection	*	*	*	*
1881	PSL Int. 90	DDB_PSLINT_90	PSL	PSLINT	PSL Internal connection	*	*	*	*
1882	PSL Int. 91	DDB_PSLINT_91	PSL	PSLINT	PSL Internal connection	*	*	*	*
1883	PSL Int. 92	DDB_PSLINT_92	PSL	PSLINT	PSL Internal connection	*	*	*	*
1884	PSL Int. 93	DDB_PSLINT_93	PSL	PSLINT	PSL Internal connection	*	*	*	*
1885	PSL Int. 94	DDB_PSLINT_94	PSL	PSLINT	PSL Internal connection	*	*	*	*
1886	PSL Int. 95	DDB_PSLINT_95	PSL	PSLINT	PSL Internal connection	*	*	*	*
1887	PSL Int. 96	DDB_PSLINT_96	PSL	PSLINT	PSL Internal connection	*	*	*	*
1888	PSL Int. 97	DDB_PSLINT_97	PSL	PSLINT	PSL Internal connection	*	*	*	*
1889	PSL Int. 98	DDB_PSLINT_98	PSL	PSLINT	PSL Internal connection	*	*	*	*
1890	PSL Int. 99	DDB_PSLINT_99	PSL	PSLINT	PSL Internal connection	*	*	*	*
1891	PSL Int. 100	DDB_PSLINT_100	PSL	PSLINT	PSL Internal connection	*	*	*	*
1892	PSL Int. 101	DDB_PSLINT_101	PSL	PSLINT	PSL Internal connection	*	*	*	*
1893	PSL Int. 102	DDB_PSLINT_102	PSL	PSLINT	PSL Internal connection	*	*	*	*
1894	PSL Int. 103	DDB_PSLINT_103	PSL	PSLINT	PSL Internal connection	*	*	*	*
1895	PSL Int. 104	DDB_PSLINT_104	PSL	PSLINT	PSL Internal connection	*	*	*	*
1896	PSL Int. 105	DDB_PSLINT_105	PSL	PSLINT	PSL Internal connection	*	*	*	*
1897	PSL Int. 106	DDB_PSLINT_106	PSL	PSLINT	PSL Internal connection	*	*	*	*
1898	PSL Int. 107	DDB_PSLINT_107	PSL	PSLINT	PSL Internal connection	*	*	*	*
1899	PSL Int. 108	DDB_PSLINT_108	PSL	PSLINT	PSL Internal connection	*	*	*	*
1900	PSL Int. 109	DDB_PSLINT_109	PSL	PSLINT	PSL Internal connection	*	*	*	*
1901	PSL Int. 110	DDB_PSLINT_110	PSL	PSLINT	PSL Internal connection	*	*	*	*
1902	PSL Int. 111	DDB_PSLINT_111	PSL	PSLINT	PSL Internal connection	*	*	*	*
1903	PSL Int. 112	DDB_PSLINT_112	PSL	PSLINT	PSL Internal connection	*	*	*	*
1904	PSL Int. 113	DDB_PSLINT_113	PSL	PSLINT	PSL Internal connection	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1905	PSL Int. 114	DDB_PSLINT_114	PSL	PSLINT	PSL Internal connection	*	*	*	*
1906	PSL Int. 115	DDB_PSLINT_115	PSL	PSLINT	PSL Internal connection	*	*	*	*
1907	PSL Int. 116	DDB_PSLINT_116	PSL	PSLINT	PSL Internal connection	*	*	*	*
1908	PSL Int. 117	DDB_PSLINT_117	PSL	PSLINT	PSL Internal connection	*	*	*	*
1909	PSL Int. 118	DDB_PSLINT_118	PSL	PSLINT	PSL Internal connection	*	*	*	*
1910	PSL Int. 119	DDB_PSLINT_119	PSL	PSLINT	PSL Internal connection	*	*	*	*
1911	PSL Int. 120	DDB_PSLINT_120	PSL	PSLINT	PSL Internal connection	*	*	*	*
1912	PSL Int. 121	DDB_PSLINT_121	PSL	PSLINT	PSL Internal connection	*	*	*	*
1913	PSL Int. 122	DDB_PSLINT_122	PSL	PSLINT	PSL Internal connection	*	*	*	*
1914	PSL Int. 123	DDB_PSLINT_123	PSL	PSLINT	PSL Internal connection	*	*	*	*
1915	PSL Int. 124	DDB_PSLINT_124	PSL	PSLINT	PSL Internal connection	*	*	*	*
1916	PSL Int. 125	DDB_PSLINT_125	PSL	PSLINT	PSL Internal connection	*	*	*	*
1917	PSL Int. 126	DDB_PSLINT_126	PSL	PSLINT	PSL Internal connection	*	*	*	*
1918	PSL Int. 127	DDB_PSLINT_127	PSL	PSLINT	PSL Internal connection	*	*	*	*
1919	PSL Int. 128	DDB_PSLINT_128	PSL	PSLINT	PSL Internal connection	*	*	*	*
1920	PSL Int. 129	DDB_PSLINT_129	PSL	PSLINT	PSL Internal connection	*	*	*	*
1921	PSL Int. 130	DDB_PSLINT_130	PSL	PSLINT	PSL Internal connection	*	*	*	*
1922	PSL Int. 131	DDB_PSLINT_131	PSL	PSLINT	PSL Internal connection	*	*	*	*
1923	PSL Int. 132	DDB_PSLINT_132	PSL	PSLINT	PSL Internal connection	*	*	*	*
1924	PSL Int. 133	DDB_PSLINT_133	PSL	PSLINT	PSL Internal connection	*	*	*	*
1925	PSL Int. 134	DDB_PSLINT_134	PSL	PSLINT	PSL Internal connection	*	*	*	*
1926	PSL Int. 135	DDB_PSLINT_135	PSL	PSLINT	PSL Internal connection	*	*	*	*
1927	PSL Int. 136	DDB_PSLINT_136	PSL	PSLINT	PSL Internal connection	*	*	*	*
1928	PSL Int. 137	DDB_PSLINT_137	PSL	PSLINT	PSL Internal connection	*	*	*	*
1929	PSL Int. 138	DDB_PSLINT_138	PSL	PSLINT	PSL Internal connection	*	*	*	*
1930	PSL Int. 139	DDB_PSLINT_139	PSL	PSLINT	PSL Internal connection	*	*	*	*
1931	PSL Int. 140	DDB_PSLINT_140	PSL	PSLINT	PSL Internal connection	*	*	*	*
1932	PSL Int. 141	DDB_PSLINT_141	PSL	PSLINT	PSL Internal connection	*	*	*	*
1933	PSL Int. 142	DDB_PSLINT_142	PSL	PSLINT	PSL Internal connection	*	*	*	*
1934	PSL Int. 143	DDB_PSLINT_143	PSL	PSLINT	PSL Internal connection	*	*	*	*
1935	PSL Int. 144	DDB_PSLINT_144	PSL	PSLINT	PSL Internal connection	*	*	*	*
1936	PSL Int. 145	DDB_PSLINT_145	PSL	PSLINT	PSL Internal connection	*	*	*	*
1937	PSL Int. 146	DDB_PSLINT_146	PSL	PSLINT	PSL Internal connection	*	*	*	*
1938	PSL Int. 147	DDB_PSLINT_147	PSL	PSLINT	PSL Internal connection	*	*	*	*
1939	PSL Int. 148	DDB_PSLINT_148	PSL	PSLINT	PSL Internal connection	*	*	*	*
1940	PSL Int. 149	DDB_PSLINT_149	PSL	PSLINT	PSL Internal connection	*	*	*	*
1941	PSL Int. 150	DDB_PSLINT_150	PSL	PSLINT	PSL Internal connection	*	*	*	*
1942	PSL Int. 151	DDB_PSLINT_151	PSL	PSLINT	PSL Internal connection	*	*	*	*
1943	PSL Int. 152	DDB_PSLINT_152	PSL	PSLINT	PSL Internal connection	*	*	*	*
1944	PSL Int. 153	DDB_PSLINT_153	PSL	PSLINT	PSL Internal connection	*	*	*	*
1945	PSL Int. 154	DDB_PSLINT_154	PSL	PSLINT	PSL Internal connection	*	*	*	*
1946	PSL Int. 155	DDB_PSLINT_155	PSL	PSLINT	PSL Internal connection	*	*	*	*
1947	PSL Int. 156	DDB_PSLINT_156	PSL	PSLINT	PSL Internal connection	*	*	*	*
1948	PSL Int. 157	DDB_PSLINT_157	PSL	PSLINT	PSL Internal connection	*	*	*	*
1949	PSL Int. 158	DDB_PSLINT_158	PSL	PSLINT	PSL Internal connection	*	*	*	*
1950	PSL Int. 159	DDB_PSLINT_159	PSL	PSLINT	PSL Internal connection	*	*	*	*
1951	PSL Int. 160	DDB_PSLINT_160	PSL	PSLINT	PSL Internal connection	*	*	*	*
1952	PSL Int. 161	DDB_PSLINT_161	PSL	PSLINT	PSL Internal connection	*	*	*	*
1953	PSL Int. 162	DDB_PSLINT_162	PSL	PSLINT	PSL Internal connection	*	*	*	*
1954	PSL Int. 163	DDB_PSLINT_163	PSL	PSLINT	PSL Internal connection	*	*	*	*
1955	PSL Int. 164	DDB_PSLINT_164	PSL	PSLINT	PSL Internal connection	*	*	*	*
1956	PSL Int. 165	DDB_PSLINT_165	PSL	PSLINT	PSL Internal connection	*	*	*	*
1957	PSL Int. 166	DDB_PSLINT_166	PSL	PSLINT	PSL Internal connection	*	*	*	*
1958	PSL Int. 167	DDB_PSLINT_167	PSL	PSLINT	PSL Internal connection	*	*	*	*
1959	PSL Int. 168	DDB_PSLINT_168	PSL	PSLINT	PSL Internal connection	*	*	*	*
1960	PSL Int. 169	DDB_PSLINT_169	PSL	PSLINT	PSL Internal connection	*	*	*	*
1961	PSL Int. 170	DDB_PSLINT_170	PSL	PSLINT	PSL Internal connection	*	*	*	*
1962	PSL Int. 171	DDB_PSLINT_171	PSL	PSLINT	PSL Internal connection	*	*	*	*
1963	PSL Int. 172	DDB_PSLINT_172	PSL	PSLINT	PSL Internal connection	*	*	*	*
1964	PSL Int. 173	DDB_PSLINT_173	PSL	PSLINT	PSL Internal connection	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
1965	PSL Int. 174	DDB_PSLINT_174	PSL	PSLINT	PSL Internal connection	*	*	*	*
1966	PSL Int. 175	DDB_PSLINT_175	PSL	PSLINT	PSL Internal connection	*	*	*	*
1967	PSL Int. 176	DDB_PSLINT_176	PSL	PSLINT	PSL Internal connection	*	*	*	*
1968	PSL Int. 177	DDB_PSLINT_177	PSL	PSLINT	PSL Internal connection	*	*	*	*
1969	PSL Int. 178	DDB_PSLINT_178	PSL	PSLINT	PSL Internal connection	*	*	*	*
1970	PSL Int. 179	DDB_PSLINT_179	PSL	PSLINT	PSL Internal connection	*	*	*	*
1971	PSL Int. 180	DDB_PSLINT_180	PSL	PSLINT	PSL Internal connection	*	*	*	*
1972	PSL Int. 181	DDB_PSLINT_181	PSL	PSLINT	PSL Internal connection	*	*	*	*
1973	PSL Int. 182	DDB_PSLINT_182	PSL	PSLINT	PSL Internal connection	*	*	*	*
1974	PSL Int. 183	DDB_PSLINT_183	PSL	PSLINT	PSL Internal connection	*	*	*	*
1975	PSL Int. 184	DDB_PSLINT_184	PSL	PSLINT	PSL Internal connection	*	*	*	*
1976	PSL Int. 185	DDB_PSLINT_185	PSL	PSLINT	PSL Internal connection	*	*	*	*
1977	PSL Int. 186	DDB_PSLINT_186	PSL	PSLINT	PSL Internal connection	*	*	*	*
1978	PSL Int. 187	DDB_PSLINT_187	PSL	PSLINT	PSL Internal connection	*	*	*	*
1979	PSL Int. 188	DDB_PSLINT_188	PSL	PSLINT	PSL Internal connection	*	*	*	*
1980	PSL Int. 189	DDB_PSLINT_189	PSL	PSLINT	PSL Internal connection	*	*	*	*
1981	PSL Int. 190	DDB_PSLINT_190	PSL	PSLINT	PSL Internal connection	*	*	*	*
1982	PSL Int. 191	DDB_PSLINT_191	PSL	PSLINT	PSL Internal connection	*	*	*	*
1983	PSL Int. 192	DDB_PSLINT_192	PSL	PSLINT	PSL Internal connection	*	*	*	*
1984	PSL Int. 193	DDB_PSLINT_193	PSL	PSLINT	PSL Internal connection	*	*	*	*
1985	PSL Int. 194	DDB_PSLINT_194	PSL	PSLINT	PSL Internal connection	*	*	*	*
1986	PSL Int. 195	DDB_PSLINT_195	PSL	PSLINT	PSL Internal connection	*	*	*	*
1987	PSL Int. 196	DDB_PSLINT_196	PSL	PSLINT	PSL Internal connection	*	*	*	*
1988	PSL Int. 197	DDB_PSLINT_197	PSL	PSLINT	PSL Internal connection	*	*	*	*
1989	PSL Int. 198	DDB_PSLINT_198	PSL	PSLINT	PSL Internal connection	*	*	*	*
1990	PSL Int. 199	DDB_PSLINT_199	PSL	PSLINT	PSL Internal connection	*	*	*	*
1991	PSL Int. 200	DDB_PSLINT_200	PSL	PSLINT	PSL Internal connection	*	*	*	*
1992	PSL Int. 201	DDB_PSLINT_201	PSL	PSLINT	PSL Internal connection	*	*	*	*
1993	PSL Int. 202	DDB_PSLINT_202	PSL	PSLINT	PSL Internal connection	*	*	*	*
1994	PSL Int. 203	DDB_PSLINT_203	PSL	PSLINT	PSL Internal connection	*	*	*	*
1995	PSL Int. 204	DDB_PSLINT_204	PSL	PSLINT	PSL Internal connection	*	*	*	*
1996	PSL Int. 205	DDB_PSLINT_205	PSL	PSLINT	PSL Internal connection	*	*	*	*
1997	PSL Int. 206	DDB_PSLINT_206	PSL	PSLINT	PSL Internal connection	*	*	*	*
1998	PSL Int. 207	DDB_PSLINT_207	PSL	PSLINT	PSL Internal connection	*	*	*	*
1999	PSL Int. 208	DDB_PSLINT_208	PSL	PSLINT	PSL Internal connection	*	*	*	*
2000	PSL Int. 209	DDB_PSLINT_209	PSL	PSLINT	PSL Internal connection	*	*	*	*
2001	PSL Int. 210	DDB_PSLINT_210	PSL	PSLINT	PSL Internal connection	*	*	*	*
2002	PSL Int. 211	DDB_PSLINT_211	PSL	PSLINT	PSL Internal connection	*	*	*	*
2003	PSL Int. 212	DDB_PSLINT_212	PSL	PSLINT	PSL Internal connection	*	*	*	*
2004	PSL Int. 213	DDB_PSLINT_213	PSL	PSLINT	PSL Internal connection	*	*	*	*
2005	PSL Int. 214	DDB_PSLINT_214	PSL	PSLINT	PSL Internal connection	*	*	*	*
2006	PSL Int. 215	DDB_PSLINT_215	PSL	PSLINT	PSL Internal connection	*	*	*	*
2007	PSL Int. 216	DDB_PSLINT_216	PSL	PSLINT	PSL Internal connection	*	*	*	*
2008	PSL Int. 217	DDB_PSLINT_217	PSL	PSLINT	PSL Internal connection	*	*	*	*
2009	PSL Int. 218	DDB_PSLINT_218	PSL	PSLINT	PSL Internal connection	*	*	*	*
2010	PSL Int. 219	DDB_PSLINT_219	PSL	PSLINT	PSL Internal connection	*	*	*	*
2011	PSL Int. 220	DDB_PSLINT_220	PSL	PSLINT	PSL Internal connection	*	*	*	*
2012	PSL Int. 221	DDB_PSLINT_221	PSL	PSLINT	PSL Internal connection	*	*	*	*
2013	PSL Int. 222	DDB_PSLINT_222	PSL	PSLINT	PSL Internal connection	*	*	*	*
2014	PSL Int. 223	DDB_PSLINT_223	PSL	PSLINT	PSL Internal connection	*	*	*	*
2015	PSL Int. 224	DDB_PSLINT_224	PSL	PSLINT	PSL Internal connection	*	*	*	*
2016	PSL Int. 225	DDB_PSLINT_225	PSL	PSLINT	PSL Internal connection	*	*	*	*
2017	PSL Int. 226	DDB_PSLINT_226	PSL	PSLINT	PSL Internal connection	*	*	*	*
2018	PSL Int. 227	DDB_PSLINT_227	PSL	PSLINT	PSL Internal connection	*	*	*	*
2019	PSL Int. 228	DDB_PSLINT_228	PSL	PSLINT	PSL Internal connection	*	*	*	*
2020	PSL Int. 229	DDB_PSLINT_229	PSL	PSLINT	PSL Internal connection	*	*	*	*
2021	PSL Int. 230	DDB_PSLINT_230	PSL	PSLINT	PSL Internal connection	*	*	*	*
2022	PSL Int. 231	DDB_PSLINT_231	PSL	PSLINT	PSL Internal connection	*	*	*	*
2023	PSL Int. 232	DDB_PSLINT_232	PSL	PSLINT	PSL Internal connection	*	*	*	*
2024	PSL Int. 233	DDB_PSLINT_233	PSL	PSLINT	PSL Internal connection	*	*	*	*

DDB No	English Text	Element Name	Source	Type	Description	P342	P343	P344	P345
2025	PSL Int. 234	DDB_PSLINT_234	PSL	PSLINT	PSL Internal connection	*	*	*	*
2026	PSL Int. 235	DDB_PSLINT_235	PSL	PSLINT	PSL Internal connection	*	*	*	*
2027	PSL Int. 236	DDB_PSLINT_236	PSL	PSLINT	PSL Internal connection	*	*	*	*
2028	PSL Int. 237	DDB_PSLINT_237	PSL	PSLINT	PSL Internal connection	*	*	*	*
2029	PSL Int. 238	DDB_PSLINT_238	PSL	PSLINT	PSL Internal connection	*	*	*	*
2030	PSL Int. 239	DDB_PSLINT_239	PSL	PSLINT	PSL Internal connection	*	*	*	*
2031	PSL Int. 240	DDB_PSLINT_240	PSL	PSLINT	PSL Internal connection	*	*	*	*
2032	PSL Int. 241	DDB_PSLINT_241	PSL	PSLINT	PSL Internal connection	*	*	*	*
2033	PSL Int. 242	DDB_PSLINT_242	PSL	PSLINT	PSL Internal connection	*	*	*	*
2034	PSL Int. 243	DDB_PSLINT_243	PSL	PSLINT	PSL Internal connection	*	*	*	*
2035	PSL Int. 244	DDB_PSLINT_244	PSL	PSLINT	PSL Internal connection	*	*	*	*
2036	PSL Int. 245	DDB_PSLINT_245	PSL	PSLINT	PSL Internal connection	*	*	*	*
2037	PSL Int. 246	DDB_PSLINT_246	PSL	PSLINT	PSL Internal connection	*	*	*	*
2038	PSL Int. 247	DDB_PSLINT_247	PSL	PSLINT	PSL Internal connection	*	*	*	*
2039	PSL Int. 248	DDB_PSLINT_248	PSL	PSLINT	PSL Internal connection	*	*	*	*
2040	PSL Int. 249	DDB_PSLINT_249	PSL	PSLINT	PSL Internal connection	*	*	*	*
2041	PSL Int. 250	DDB_PSLINT_250	PSL	PSLINT	PSL Internal connection	*	*	*	*
2042	PSL Int. 251	DDB_PSLINT_251	PSL	PSLINT	PSL Internal connection	*	*	*	*
2043	PSL Int. 252	DDB_PSLINT_252	PSL	PSLINT	PSL Internal connection	*	*	*	*
2044	PSL Int. 253	DDB_PSLINT_253	PSL	PSLINT	PSL Internal connection	*	*	*	*
2045	PSL Int. 254	DDB_PSLINT_254	PSL	PSLINT	PSL Internal connection	*	*	*	*
2046	PSL Int. 255	DDB_PSLINT_255	PSL	PSLINT	PSL Internal connection	*	*	*	*
2047	PSL Int. 256	DDB_PSLINT_256	PSL	PSLINT	PSL Internal connection	*	*	*	*

Table 1 - Description of available Logic Nodes

3 DEFAULT PROGRAMMABLE SCHEME LOGIC (PSL)

3.1 Factory Default Programmable Scheme Logic

Model	Opto Inputs	Relay Outputs
P342xxxxxxxxxxL	8-24	7-24
P343xxxxxxxxxxM	16-32	14-32
P344xxxxxxxxxxM	16-32	16-32
P345xxxxxxxxxxM	16-32	16-32

Table 2 - Default settings

3.2 Logic Input Mapping

The default mappings for each of the opto-isolated inputs are shown in Table 3:

Opto-Input No	P342 relay text	Function		P343/P344/P345 relay text	Function
1	Input L1	L1 Setting Group selection		Input L1	L1 Setting Group selection
2	Input L2	L2 Setting Group selection		Input L2	L2 Setting Group selection
3	Input L3	L3 Block IN>2 Timer		Input L3	L3 Block IN>2 Timer
4	Input L4	L4 Block I>2 Timer		Input L4	L4 Block I>2 Timer
5	Input L5	L5 Reset Relays and LEDs		Input L5	L5 Reset Relays and LEDs
6	Input L6	L6 Ext Prot Trip		Input L6	L6 Ext Prot Trip
7	Input L7	L7 52a (CB Status)		Input L7	L7 52a (CB Status)
8	Input L8	L8 52b (CB Status)		Input L8	L8 52b (CB Status)
9	Input L9	Not Used		Input L9	L9 Not Used
10	Input L10	Not Used		Input L10	L10 Not Used
11	Input L11	Not Used		Input L11	L11 Not Used
12	Input L12	Not Used		Input L12	L12 Not Used
13	Input L13	Not Used		Input L13	L13 Not Used
14	Input L14	Not Used		Input L14	L14 Not Used
15	Input L15	Not Used		Input L15	L15 Not Used
16	Input L16	Not Used		Input L16	L16 Not Used
17	Input L17	Not Used		Input L17	L17 Not Used
18	Input L18	Not Used		Input L18	L18 Not Used
19	Input L19	Not Used		Input L19	L19 Not Used
20	Input L20	Not Used		Input L20	L20 Not Used
21	Input L21	Not Used		Input L21	L21 Not Used
22	Input L22	Not Used		Input L22	L22 Not Used
23	Input L23	Not Used		Input L23	L23 Not Used
24	Input L24	Not Used		Input L24	L24 Not Used
25		Not Used		Input L25	L25 Not Used
26		Not Used		Input L26	L26 Not Used
27		Not Used		Input L27	L27 Not Used
28		Not Used		Input L28	L28 Not Used
29		Not Used		Input L29	L29 Not Used
30		Not Used		Input L30	L30 Not Used
31		Not Used		Input L31	L31 Not Used
32		Not Used		Input L32	L32 Not Used

Table 3 – P342 and P343/P344/P345 opto inputs default mappings

3.3 Relay Output Contact Mapping

The default mappings for each of the relay output contacts are as shown inTable 4:

Relay contact No	P342 relay text	P342 relay conditioner	Function		P343/P344/ P345 relay text	P343/P344/P345 relay conditioner	Function
1	Output R1	Dwell 100 ms	R1 Trip CB		Output R1	Dwell 100 ms	R1 Trip CB
2	Output R2	Dwell 100 ms	R2 Trip Prime Mover		Output R2	Dwell 100 ms	R2 Trip Prime Mover
3	Output R3	Dwell 100 ms	R3 Any Protection Trip		Output R3	Dwell 100 ms	R3 Any Protection Trip
4	Output R4	Delayed Drop-off timer 500 ms	R4 General Alarm		Output R4	Delayed Drop-off timer 500 ms	R4 General Alarm
5	Output R5	Dwell 100 ms	R5 CB Fail		Output R5	Dwell 100 ms	R5 CB Fail
6	Output R6	Straight-through	R6 Earth Fault Protection Trip		Output R6	Straight-through	R6 Earth Fault Protection Trip
7	Output R7	Straight-through	R7 Voltage or Frequency Protection Trip		Output R7	Straight-through	R7 Voltage Protection Trip
8	Output R8	Straight-through	Not Used		Output R8	Straight-through	R8 Frequency Protection trip
9	Output R9	Straight-through	Not Used		Output R9	Straight-through	R9 Differential Protection Trip
10	Output R10	Straight-through	Not Used		Output R10	Straight-through	R10 System Back-up Protection Trip
11	Output R11	Straight-through	Not Used		Output R11	Straight-through	R11 NPS Protection Trip
12	Output R12	Straight-through	Not Used		Output R12	Straight-through	R12 Field Failure Protection Trip
13	Output R13	Straight-through	Not Used		Output R13	Straight-through	R13 Power Protection Trip
14	Output R14	Straight-through	Not Used		Output R14	Straight-through	R14 V/Hz Protection Trip
15	Output R15	Straight-through	Not Used		Output R15	Straight-through	Not Used
16	Output R16	Straight-through	Not Used		Output R16	Straight-through	Not Used
17	Output R17	Straight-through	Not Used		Output R17	Straight-through	Not Used
18	Output R18	Straight-through	Not Used		Output R18	Straight-through	Not Used
19	Output R19	Straight-through	Not Used		Output R19	Straight-through	R19 Not Used
20	Output R20	Straight-through	Not Used		Output R20	Straight-through	Not Used
21	Output R21	Straight-through	Not Used		Output R21	Straight-through	Not Used
22	Output R22	Straight-through	Not Used		Output R22	Straight-through	Not Used
23	Output R23	Straight-through	Not Used		Output R23	Straight-through	Not Used
24	Output R24	Straight-through	Not Used		Output R24	Straight-through	Not Used
25					Output R25	Straight-through	Not Used
26					Output R26	Straight-through	Not Used
27					Output R27	Straight-through	Not Used
28					Output R28	Straight-through	Not Used
29					Output R29	Straight-through	Not Used
30					Output R30	Straight-through	Not Used

Relay contact No	P342 relay text	P342 relay conditioner	Function		P343/P344/ P345 relay text	P343/P344/P345 relay conditioner	Function
31					Output R31	Straight-through	Not Used
32					Output R32	Straight-through	Not Used

Table 4 – P342 and P343/P344/P345 relay output contacts default mappings

Note	*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 a latching. If a latching contact were chosen the fault record would not be generated until the contact had fully reset.*

3.4 Programmable LED Output Mapping

The default mappings for each of the programmable LEDs are as shown in Table 5 for (P342 has red LEDs and the P343/P344/P345 which have tri-color LEDS (red/yellow/green):

LED No	LED Input connection/text	Latched	P342 LED function indication		LED Input connection/text	Latched	P343/P344/P345 LED function indication
1	LED 1 Red	Yes	Earth Fault Protection Trip		LED 1 Red	Yes	Earth Fault Protection Trip
2	LED 2 Red	Yes	Overcurrent Protection Trip		LED 2 Red	Yes	Overcurrent Protection Trip
3	LED 3 Red	Yes	Field Failure Protection Trip		LED 3 Red	Yes	Field Failure Protection Trip
4	LED 4 Red	Yes	NPS Protection Trip		LED 4 Red	Yes	NPS Protection Trip
5	LED 5 Red	Yes	Voltage Protection Trip		LED 5 Red	Yes	Voltage Protection Trip
6	LED 6 Red	Yes	Frequency Protection Trip		LED 6 Red	Yes	Frequency Protection Trip
7	LED 7 Red	Yes	Power Protection Trip		LED 7 Red	Yes	Power Protection Trip
8	LED 8 Red	No	Any Start		LED 8 Red	No	Any Start
9					FnKey LED1	No	Not Used
10					FnKey LED2	No	Not Used
11					FnKey LED3	No	Not Used
12					FnKey LED4 Red (Fnct Key is Toggled mode)	No	Inhibit Turbine Abnormal Frequency Protection
13					FnKey LED5 Red (Fnct Key is Toggled mode)	No	Enable Setting Group 2
14					FnKey LED6	No	Not Used
15					FnKey LED7 Yellow (Fnct Key is Normal mode)	No	Reset NPS Thermal measurement to 0
16					FnKey LED8 Yellow (Fnct Key is Normal mode)	No	Reset Thermal Overload Measurement to 0
17					FnKey LED9 Yellow (Fnct Key is Normal mode)	No	Reset Relays and LEDs
18					FnKey LED10 Yellow (Fnct Key is Normal mode)	No	Trigger disturbance recorder

Table 5 - P343/P344/P345 programmable LED default mappings

3.5 Fault Recorder Start Mapping

The default mapping for the signal which initiates a fault record is as shown in Table 6:

Initiating Signal	Fault Trigger
Relay 3 (DDB 002)	Initiate fault recording from main protection trip

Table 6 - Fault recorder start mapping

3.6 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.*

4 VIEWING AND PRINTING DEFAULT PSL DIAGRAMS

4.1 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

Important	***The following PSL diagrams show the DDB numbers for a specific MiCOM product, with a specific software version to run on a specific hardware platform. Descriptions, DDB Numbers, Inputs and Outputs may vary for different products, software or hardware.***

4.2 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**.

5 P342 PROGRAMMABLE SCHEME LOGIC

5.1 Input Mappings

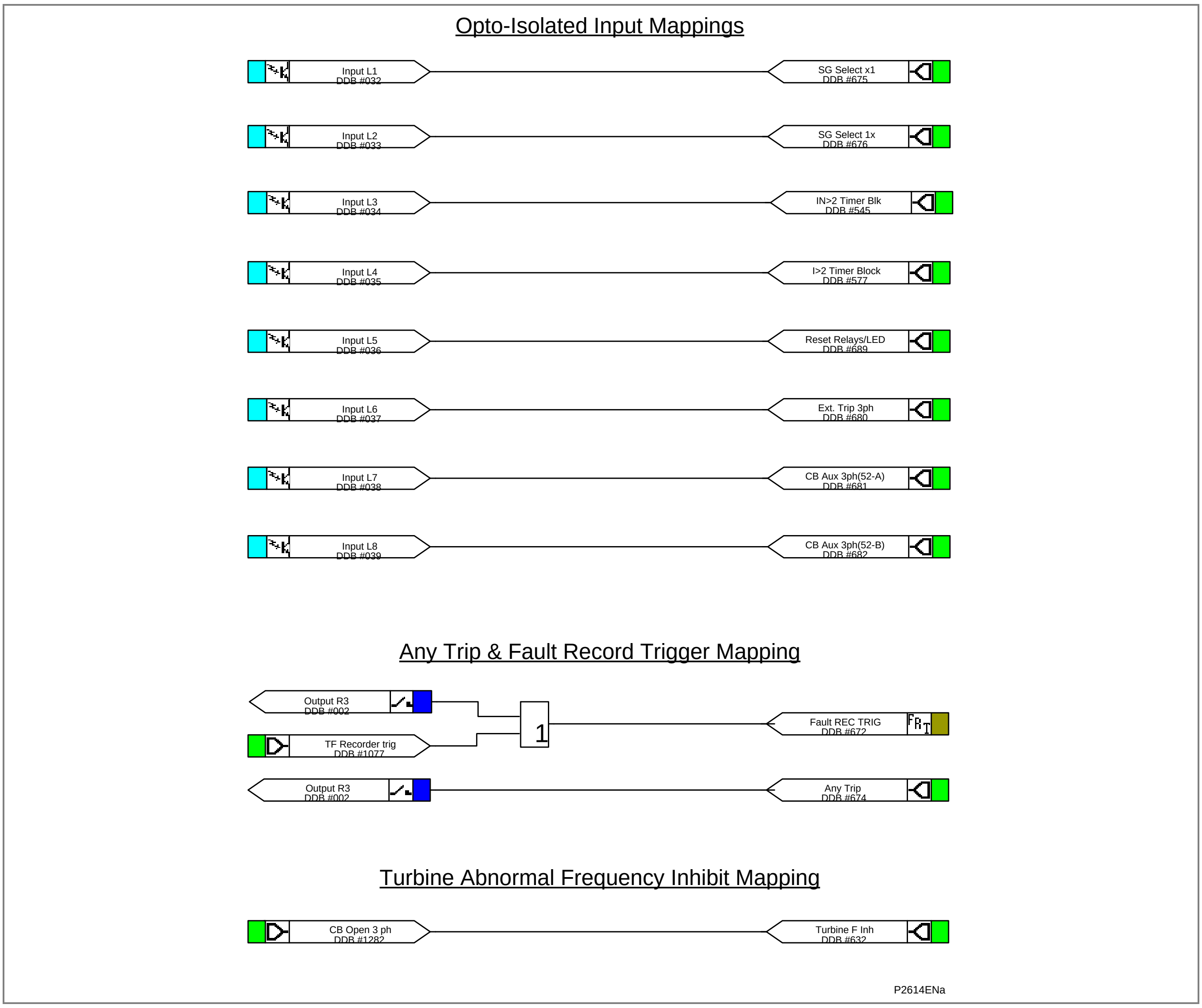

Figure 1 - Opto input mappings

5.2 Output Mappings

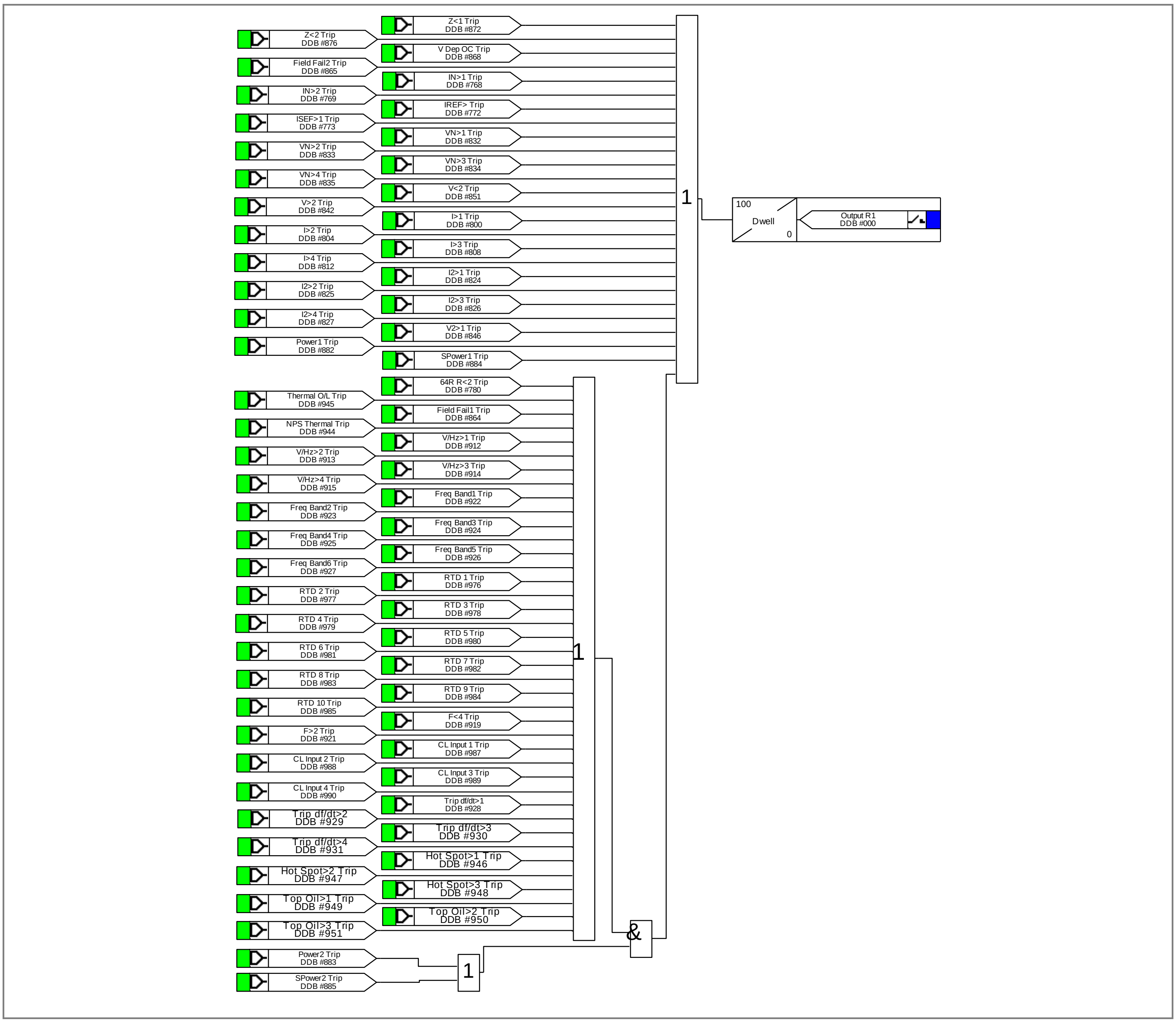

Figure 2 - Output relay R1 (Trip CB) mappings

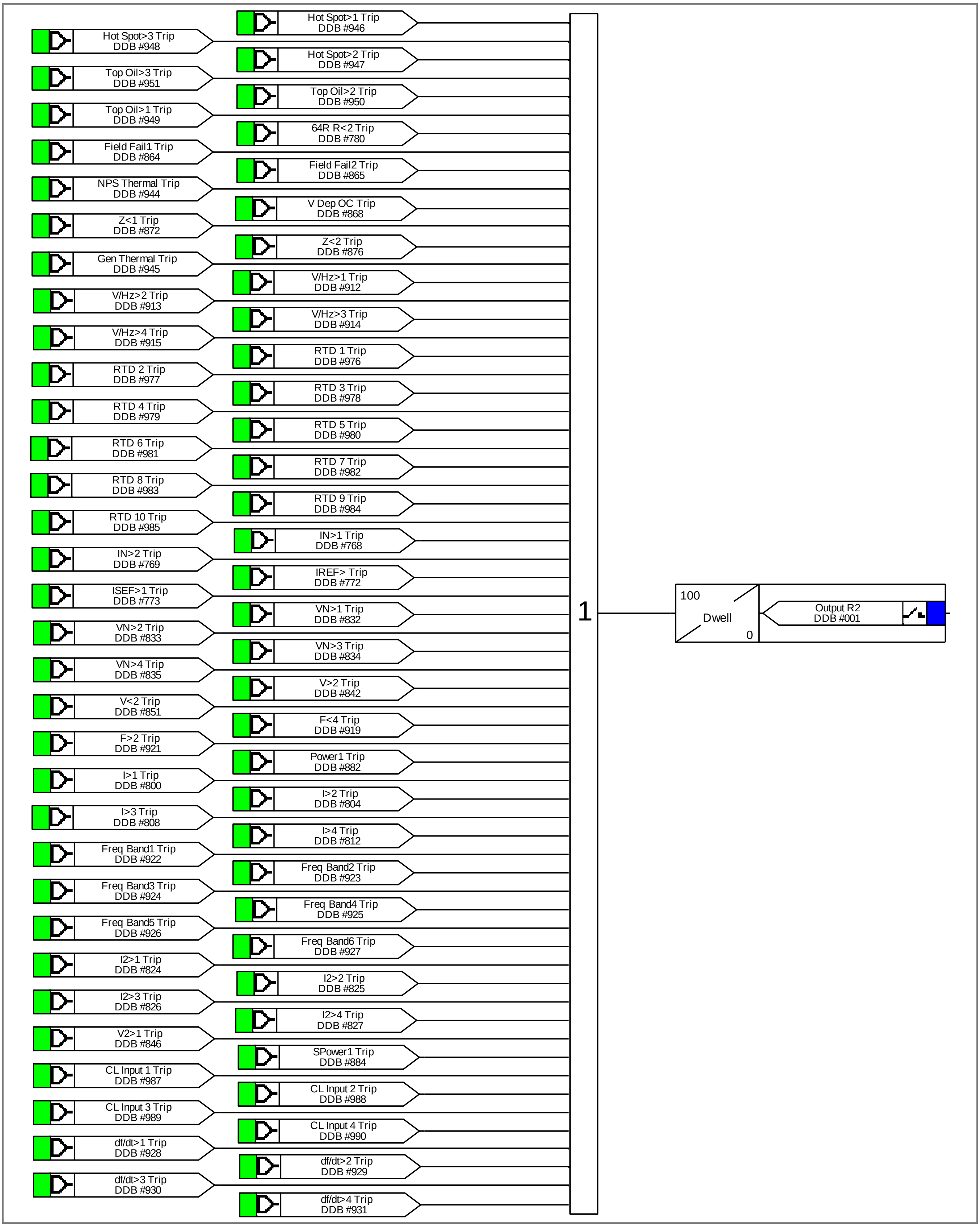

Figure 3 - Output relay R2 (Trip Prime Mover) mappings

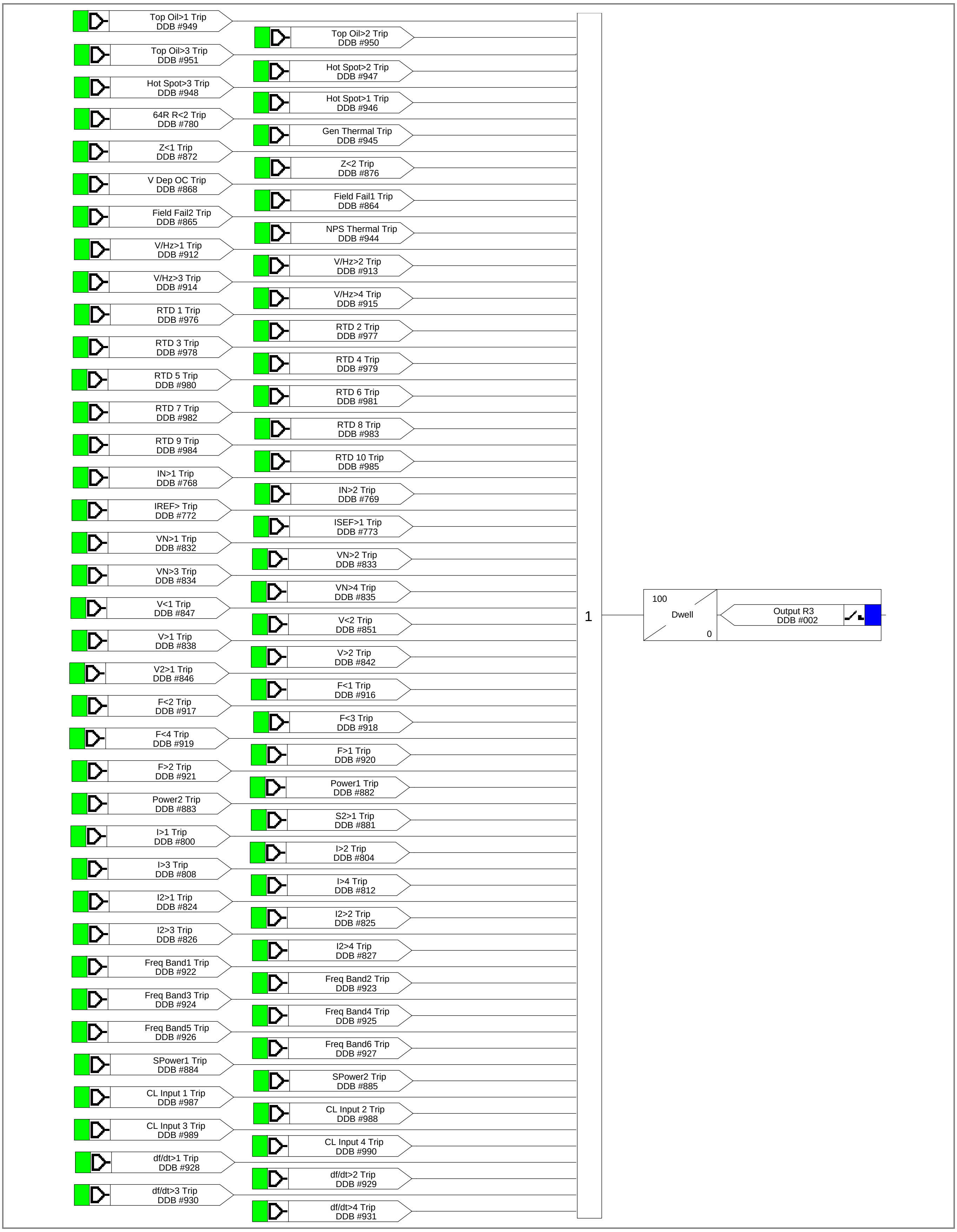

Figure 4 - Output relay R3 (Any Trip) mappings

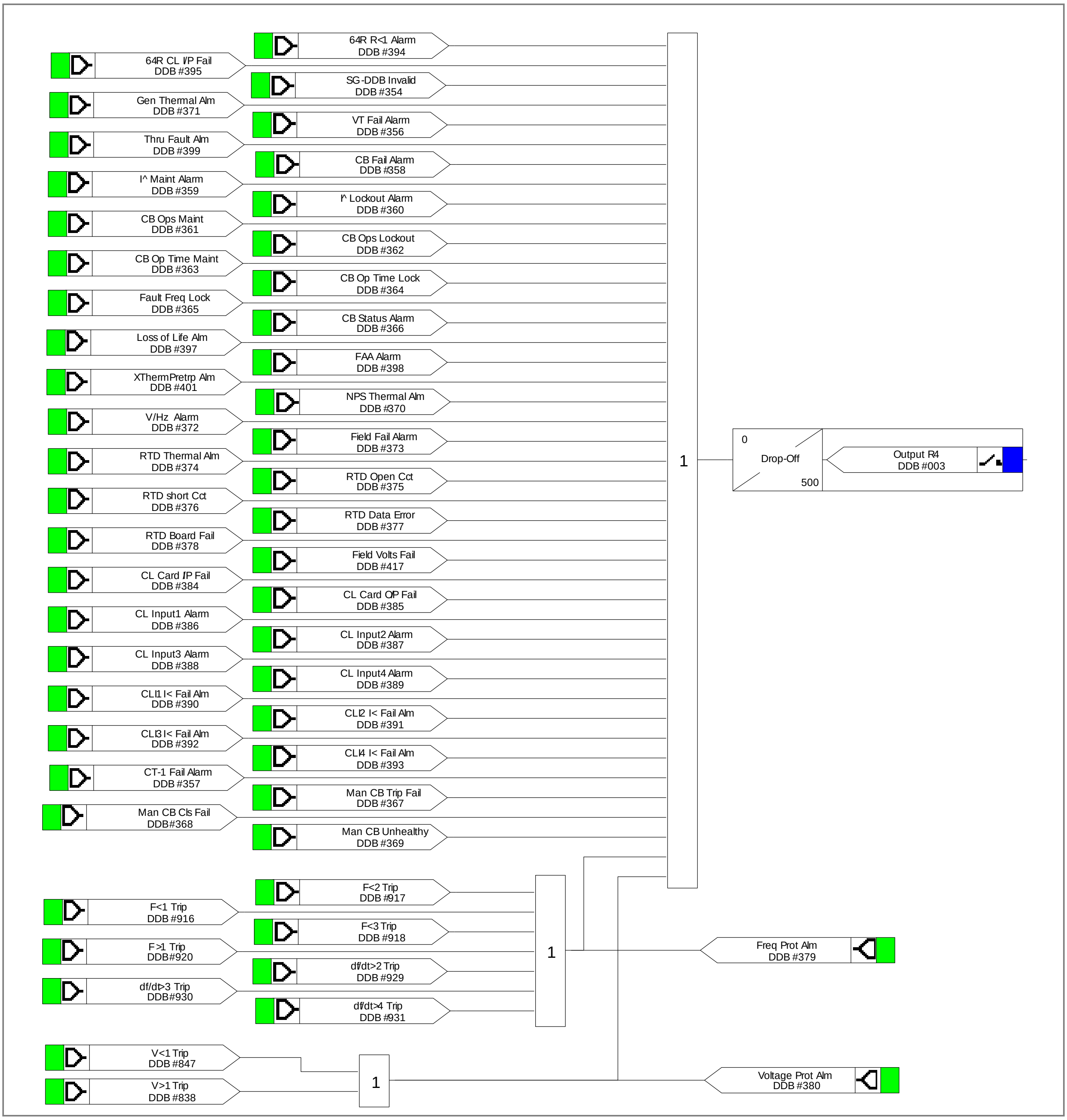

Figure 5 - Output relay R4 (General Alarm) mappings

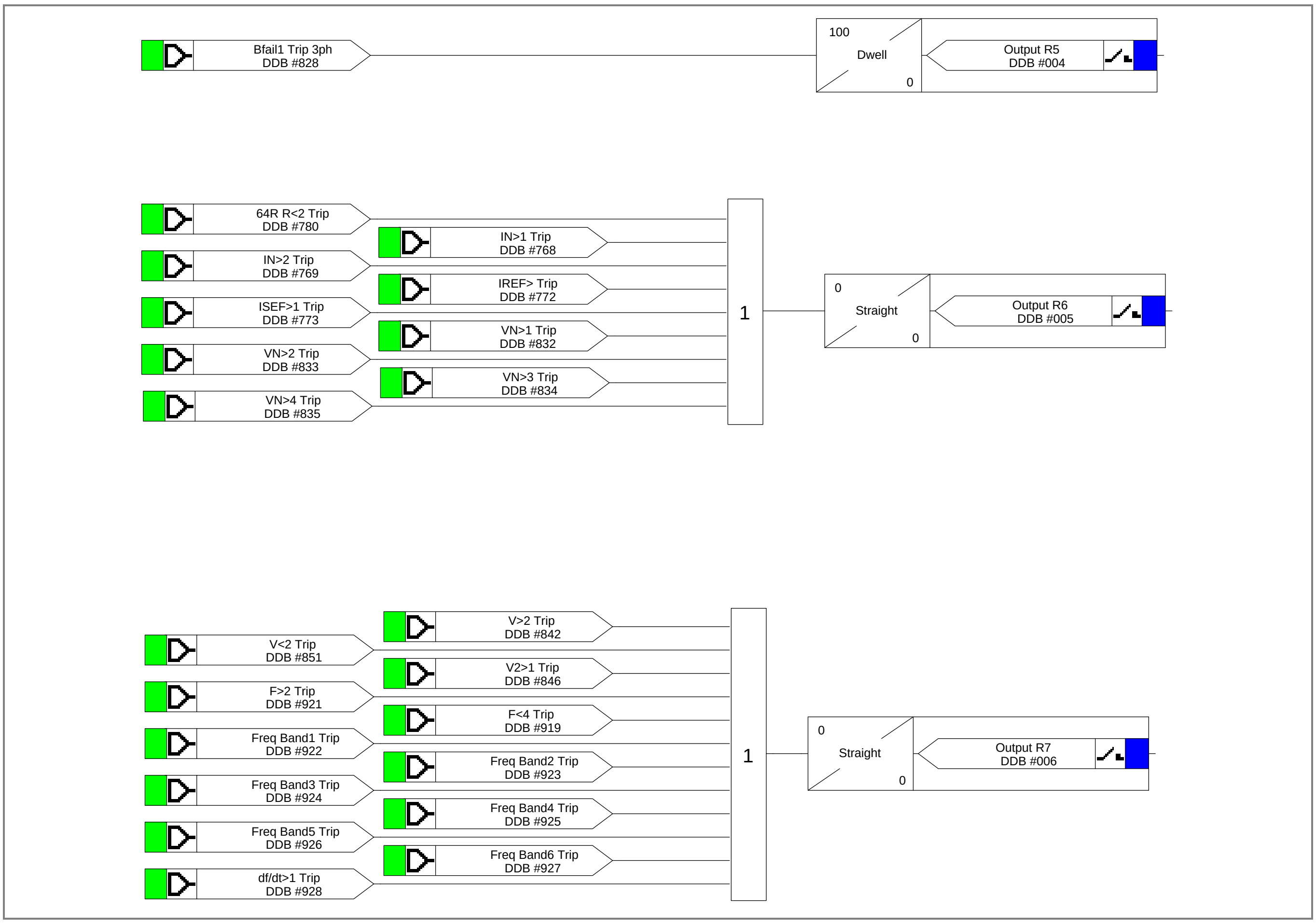

Figure 6 - Output relay mappings

5.3 Check Synch Mapping

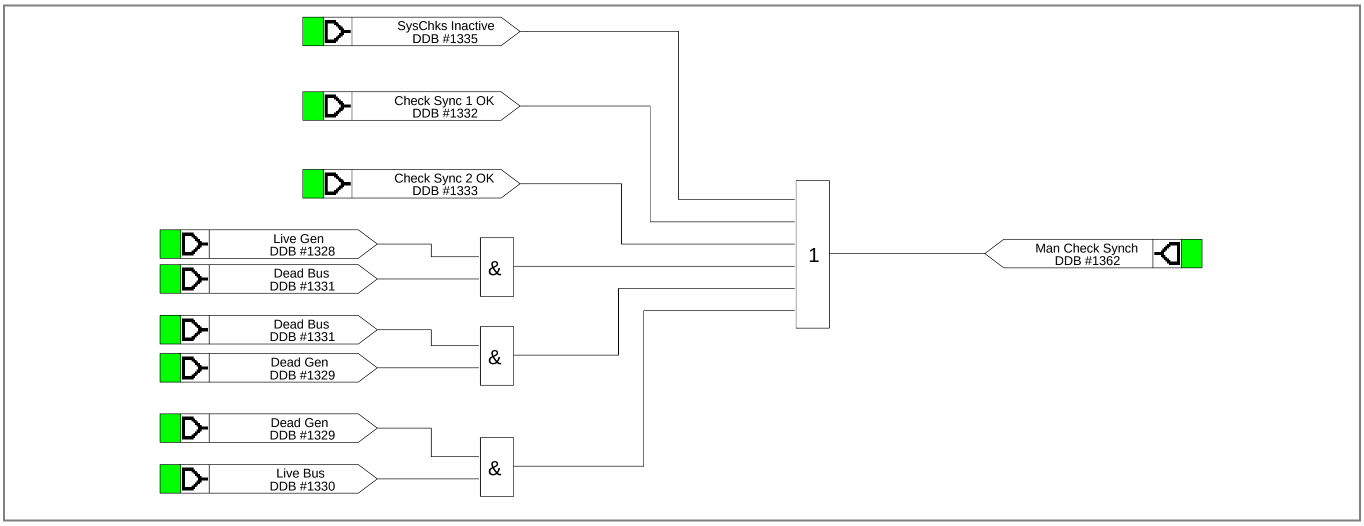

Figure 7 - Check synch and voltage monitor mapping

5.4 LED Mappings

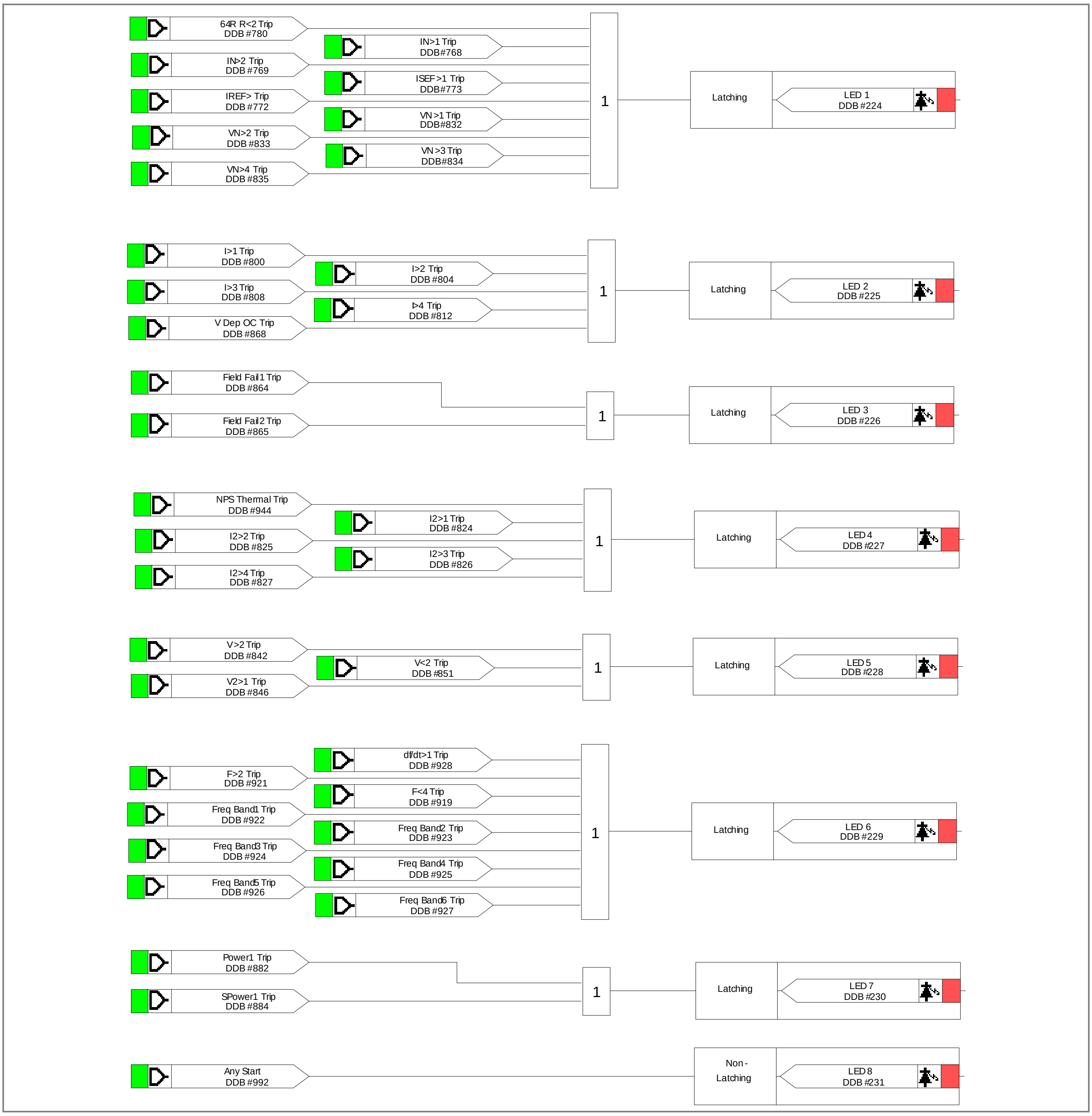

Figure 8 - LED output mappings

6 P343 PROGRAMMABLE SCHEME LOGIC

6.1 Input Mappings

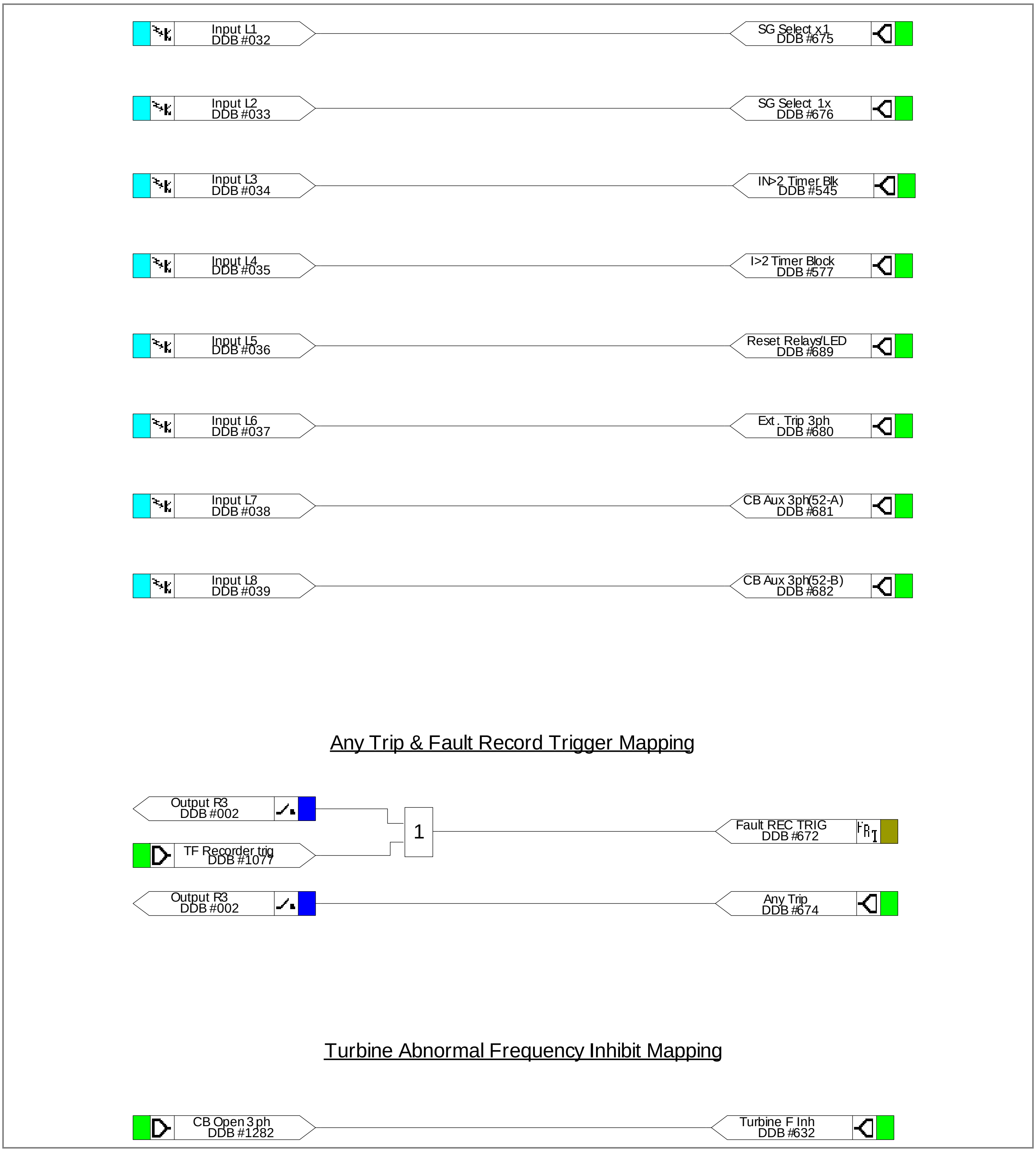

Figure 9 - Opto input mappings

6.2 Output Mappings

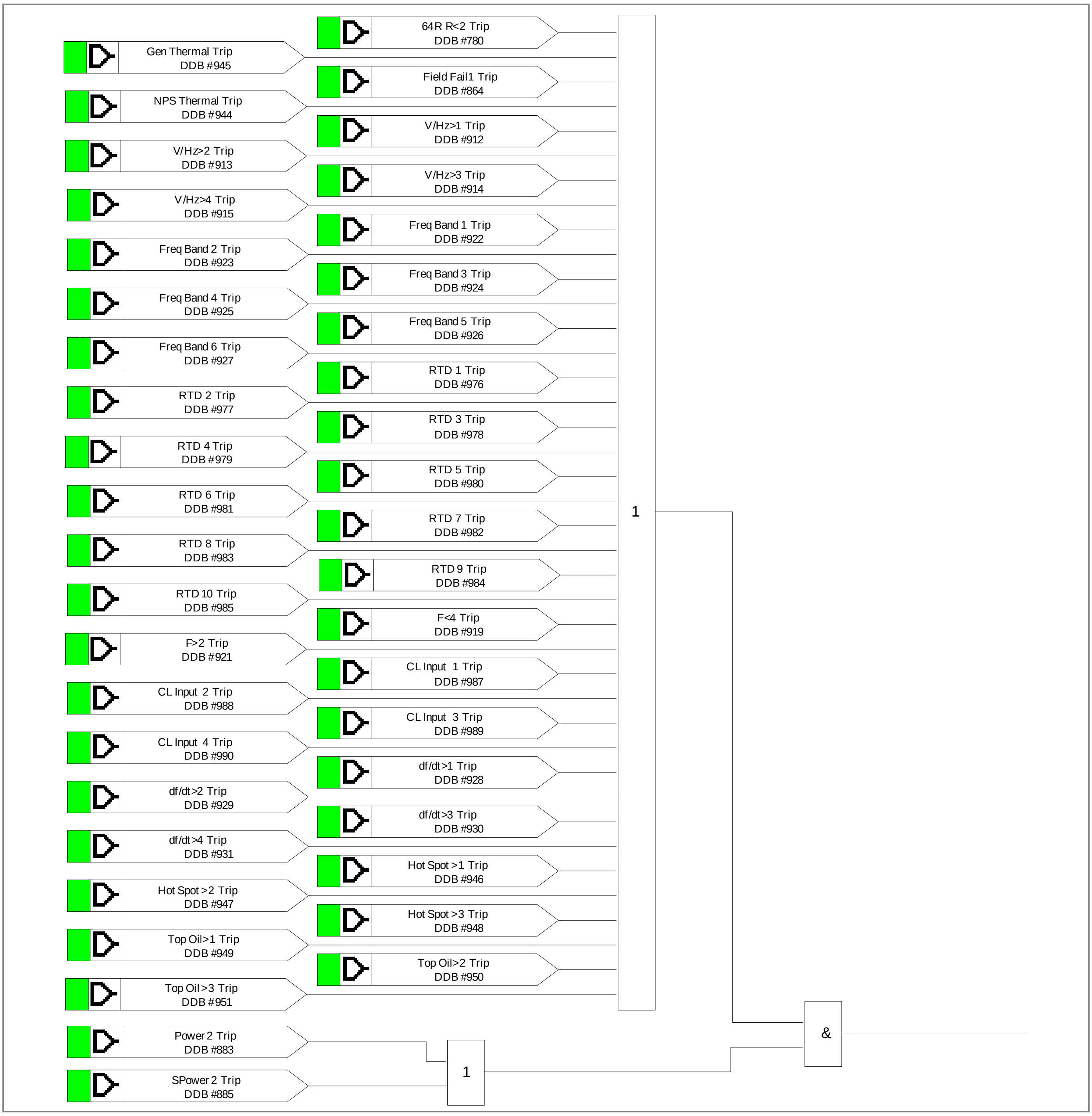

Figure 10 - Output relay R1 (Trip CB) mappings

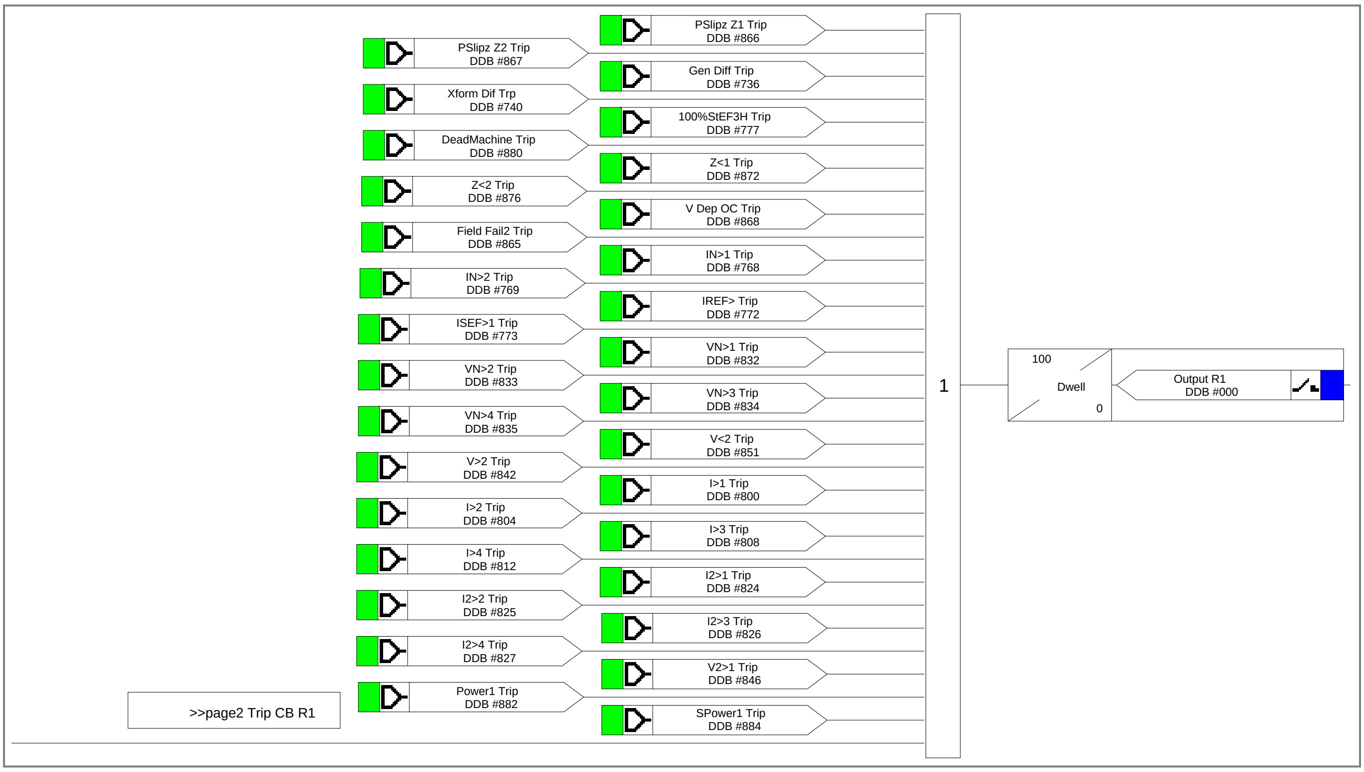

Figure 11 - Output relay R1 (Trip CB) mappings

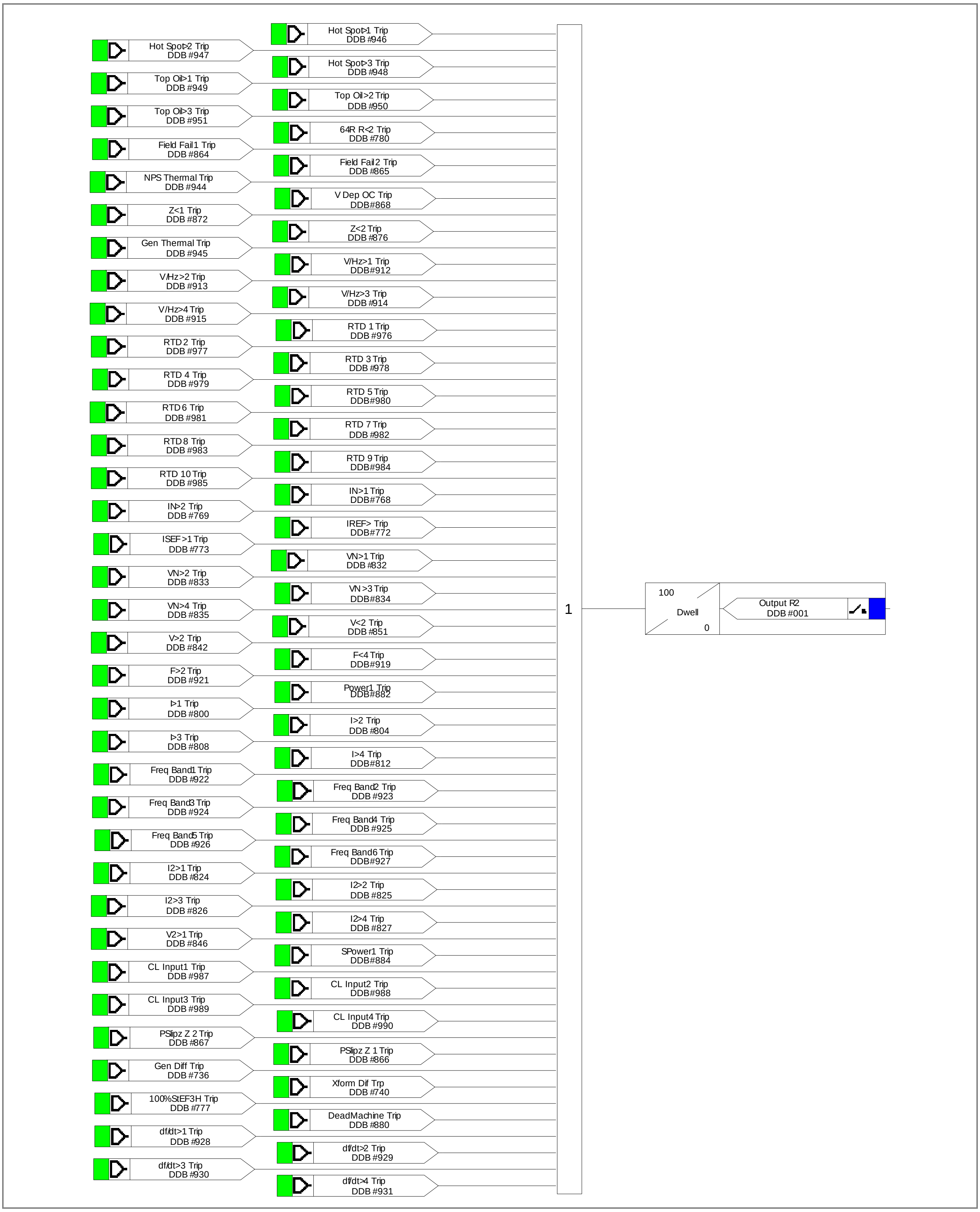

Figure 12 - Output relay R2 (Trip Prime Mover) mappings

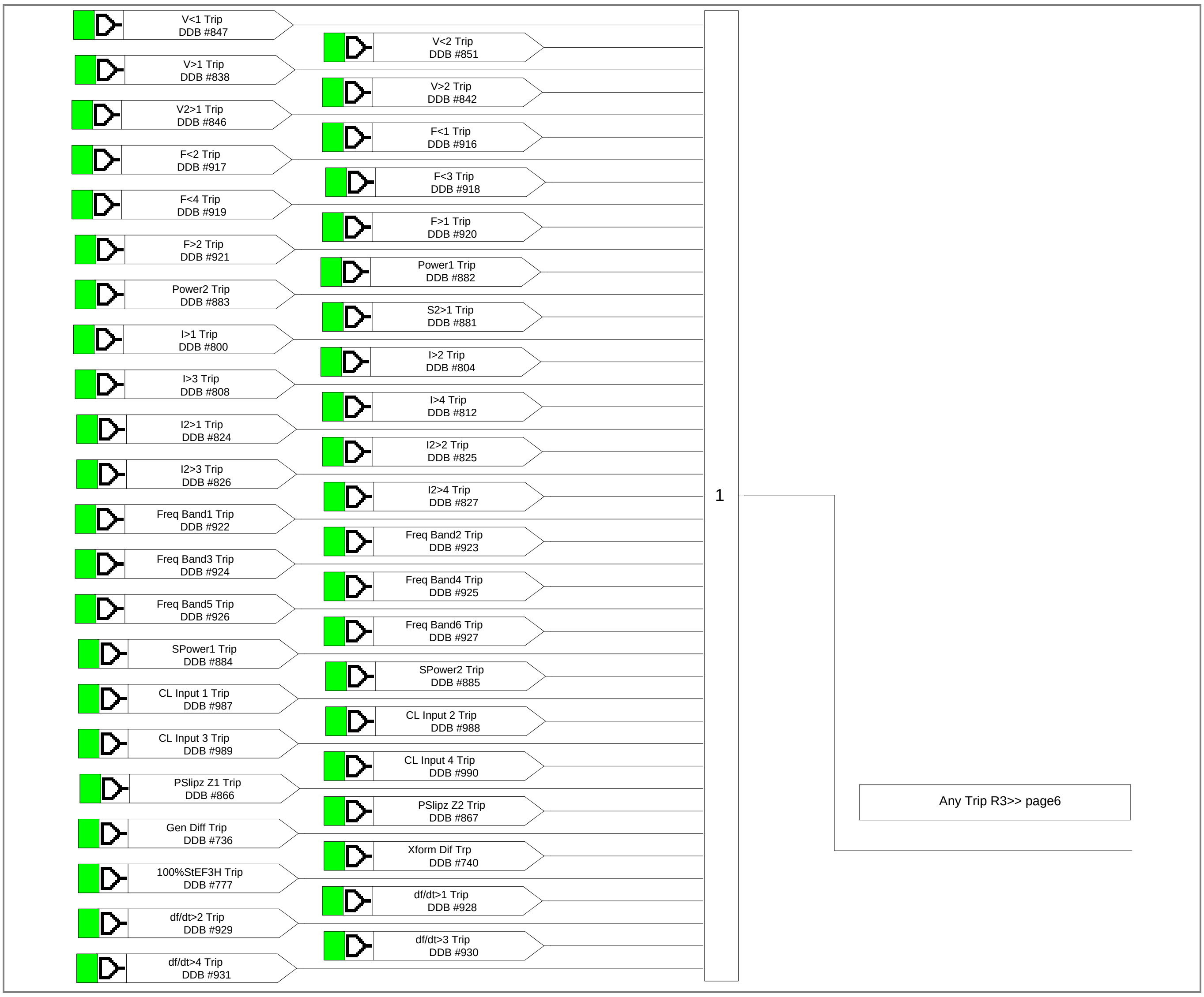

Figure 13 - Output relay R3 (Any Trip) mappings

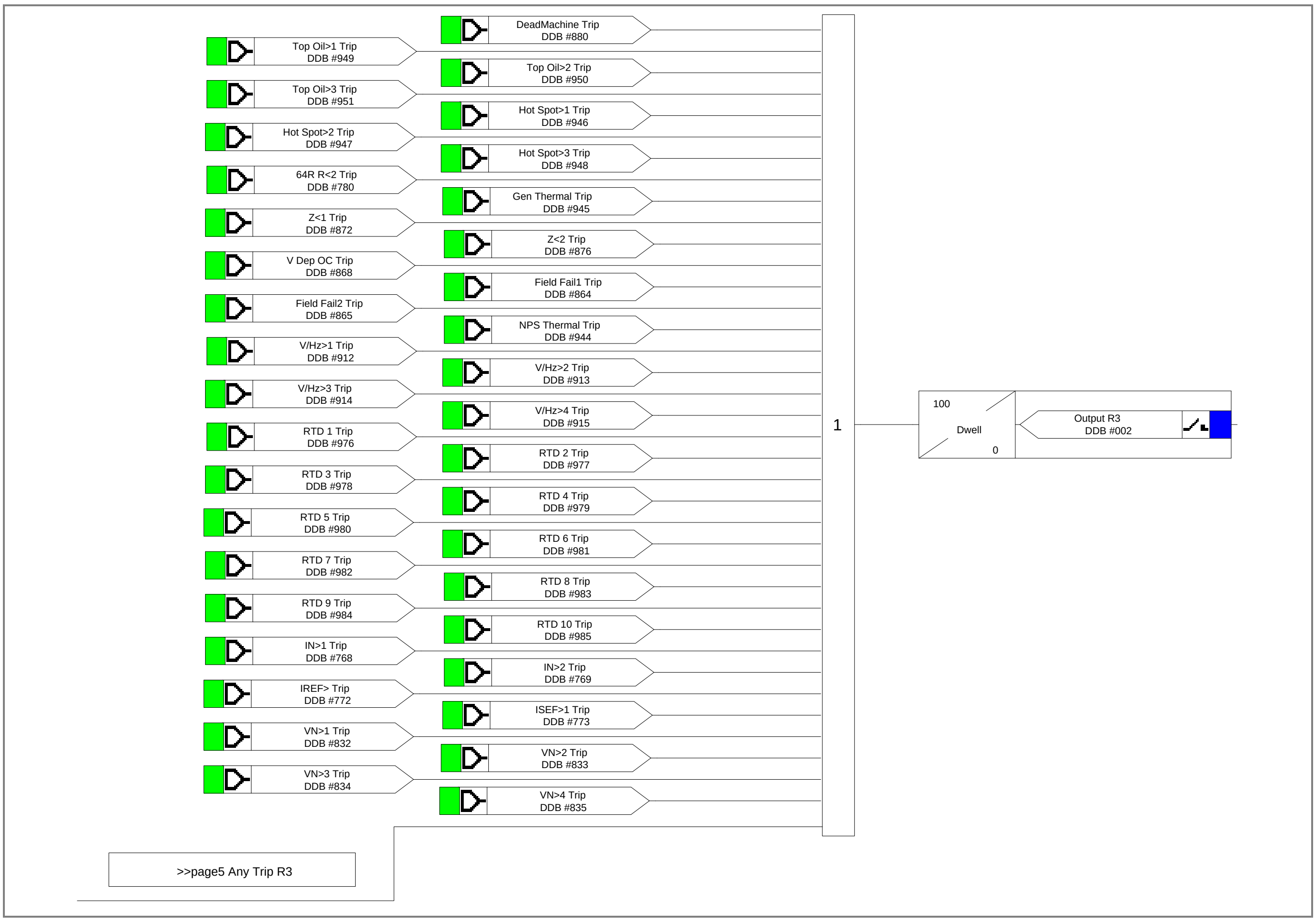

Figure 14 - Output relay R4 (General Alarm) mappings

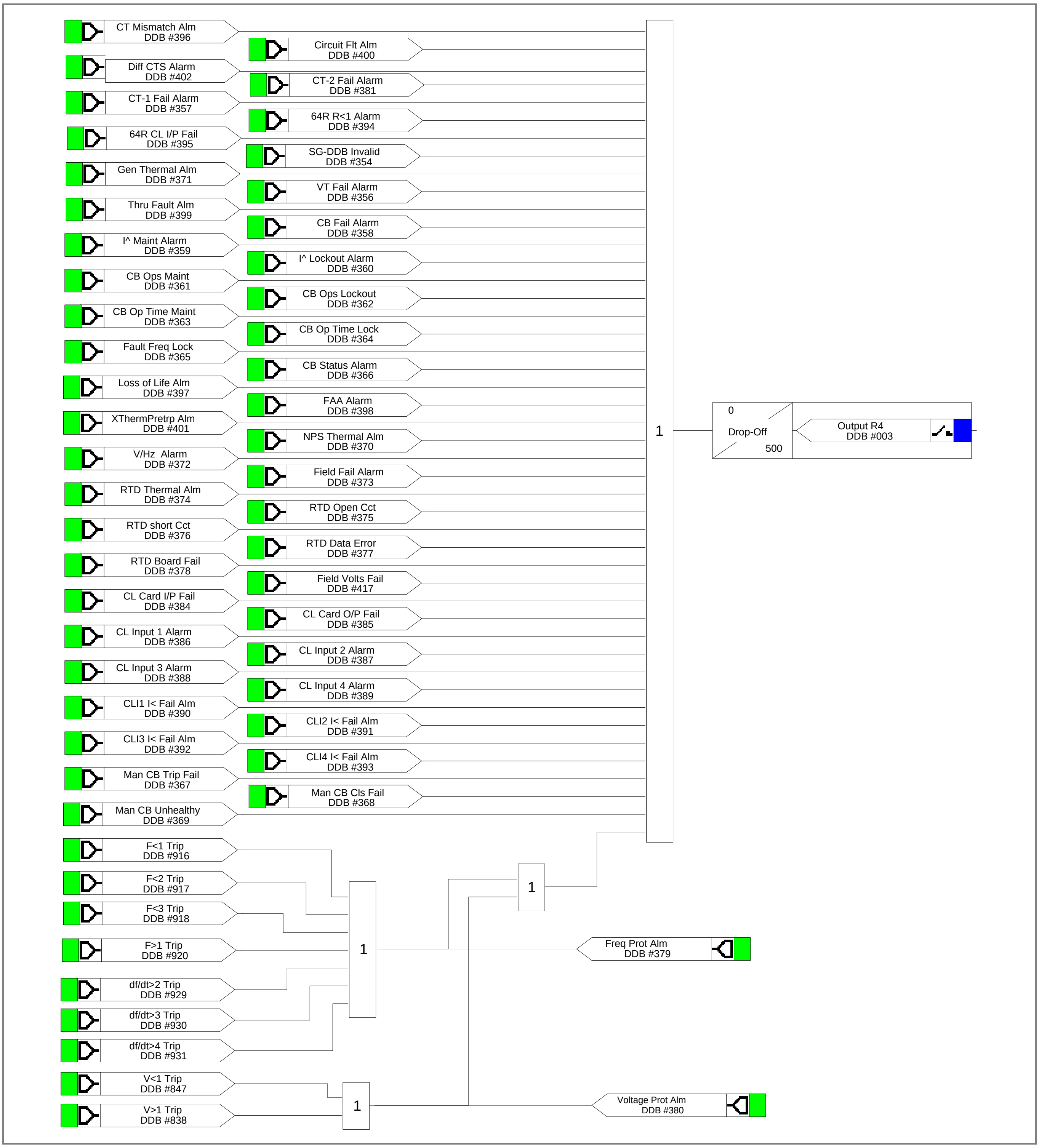

Figure 15 - Output relay mappings

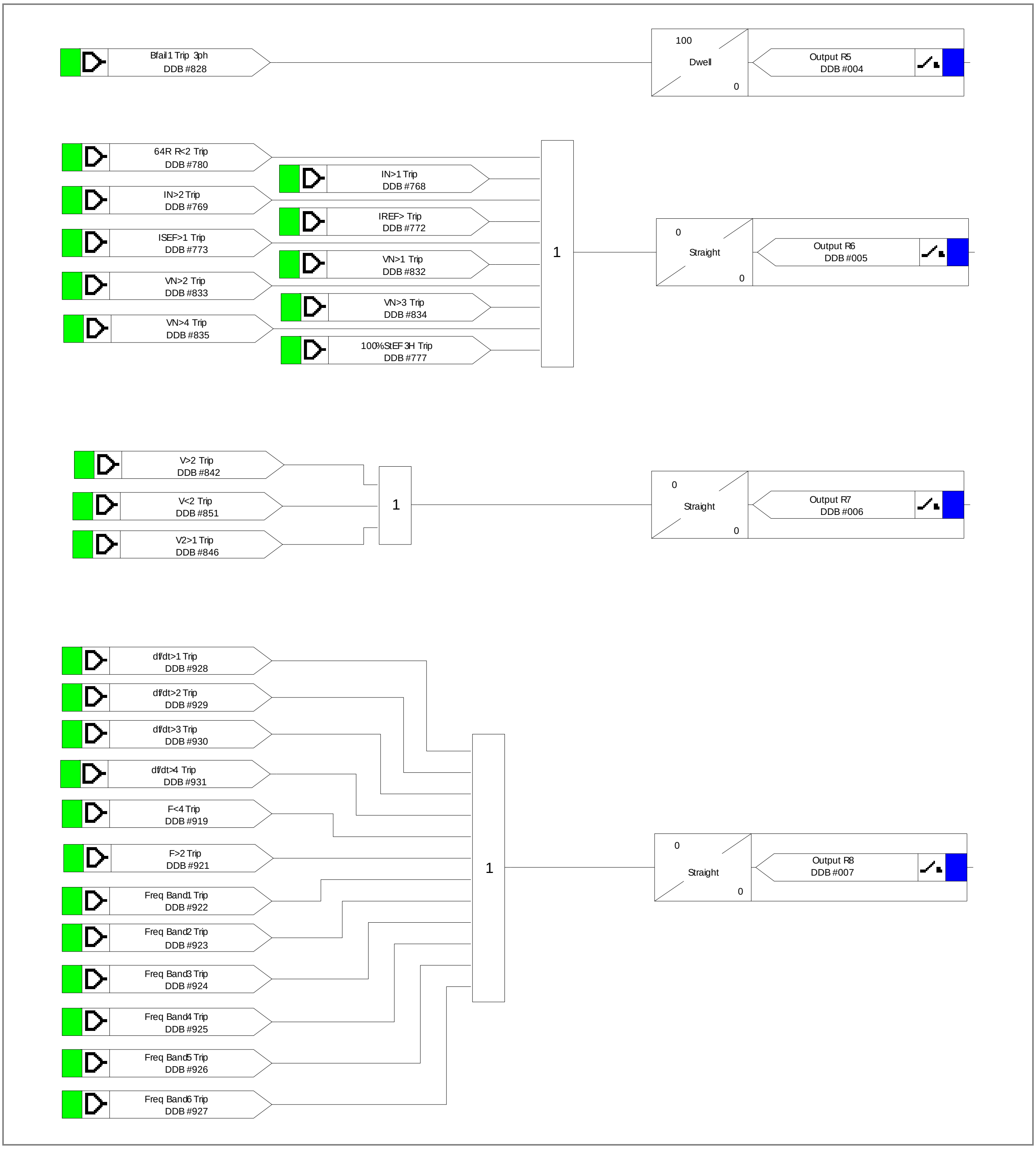

Figure 16 - Output relay mappings

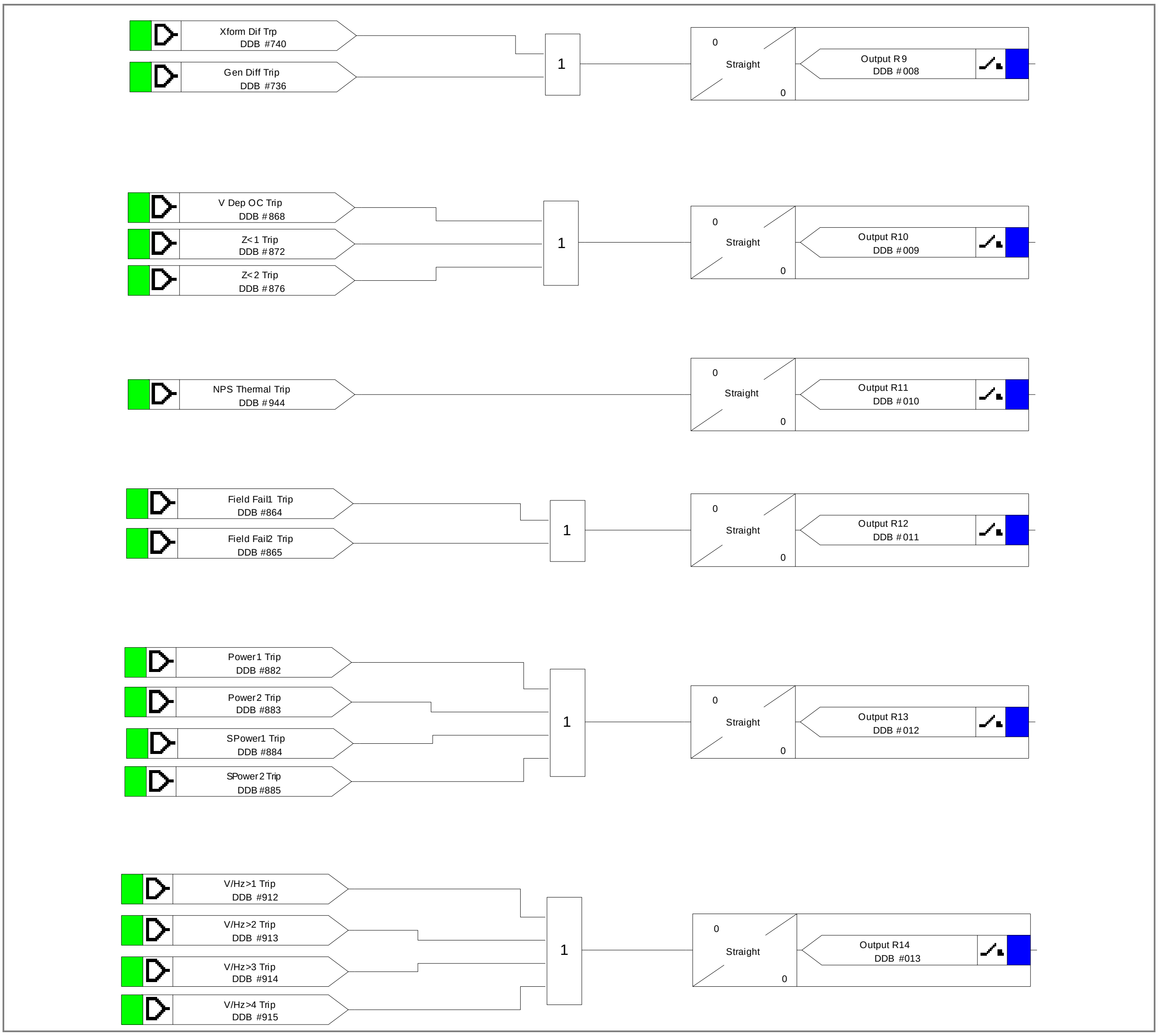

Figure 17 - Output relay mappings

6.3 LED Mapping

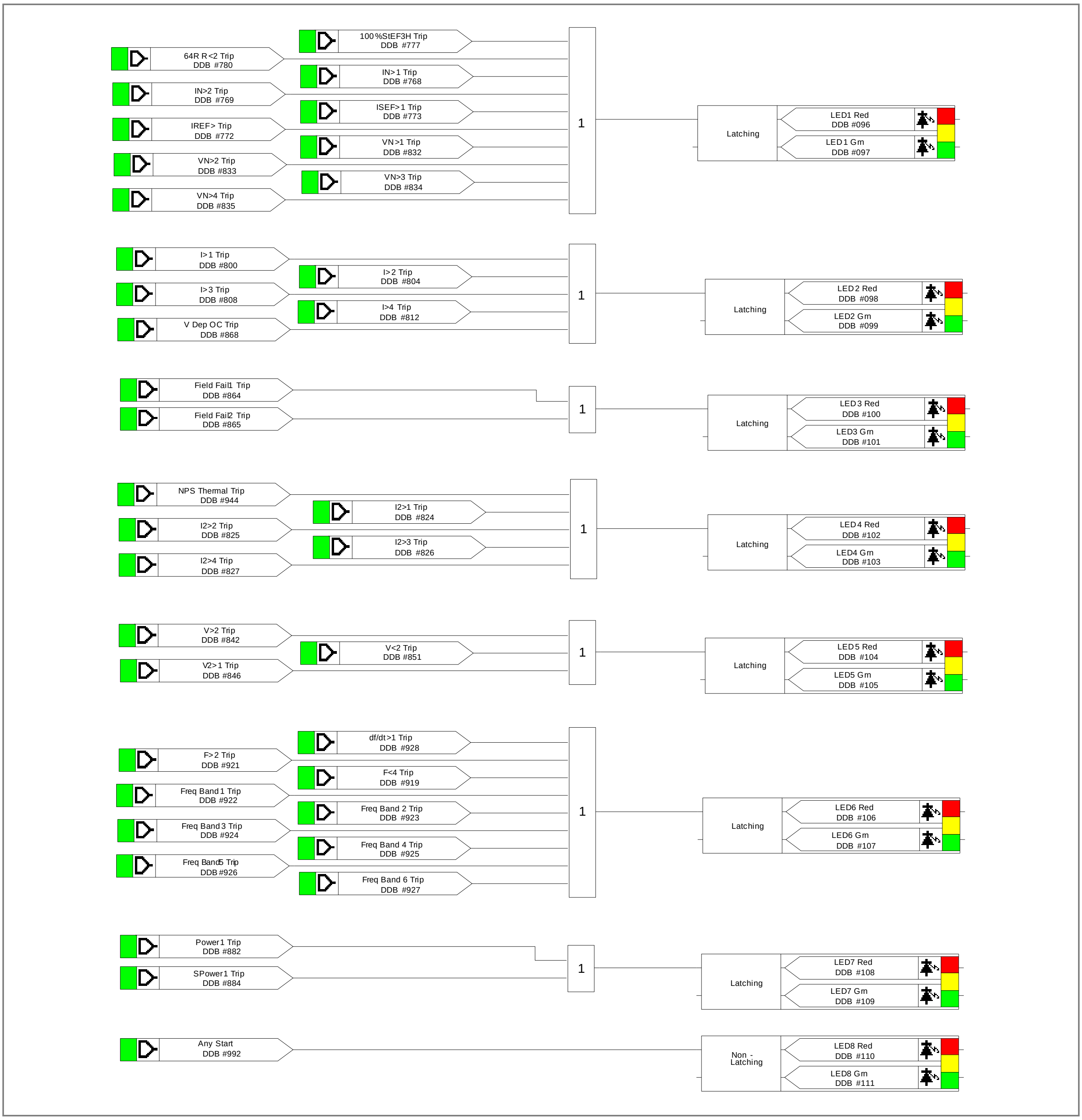

Figure 18 - LED output mapping

6.4 Function and LED Mapping

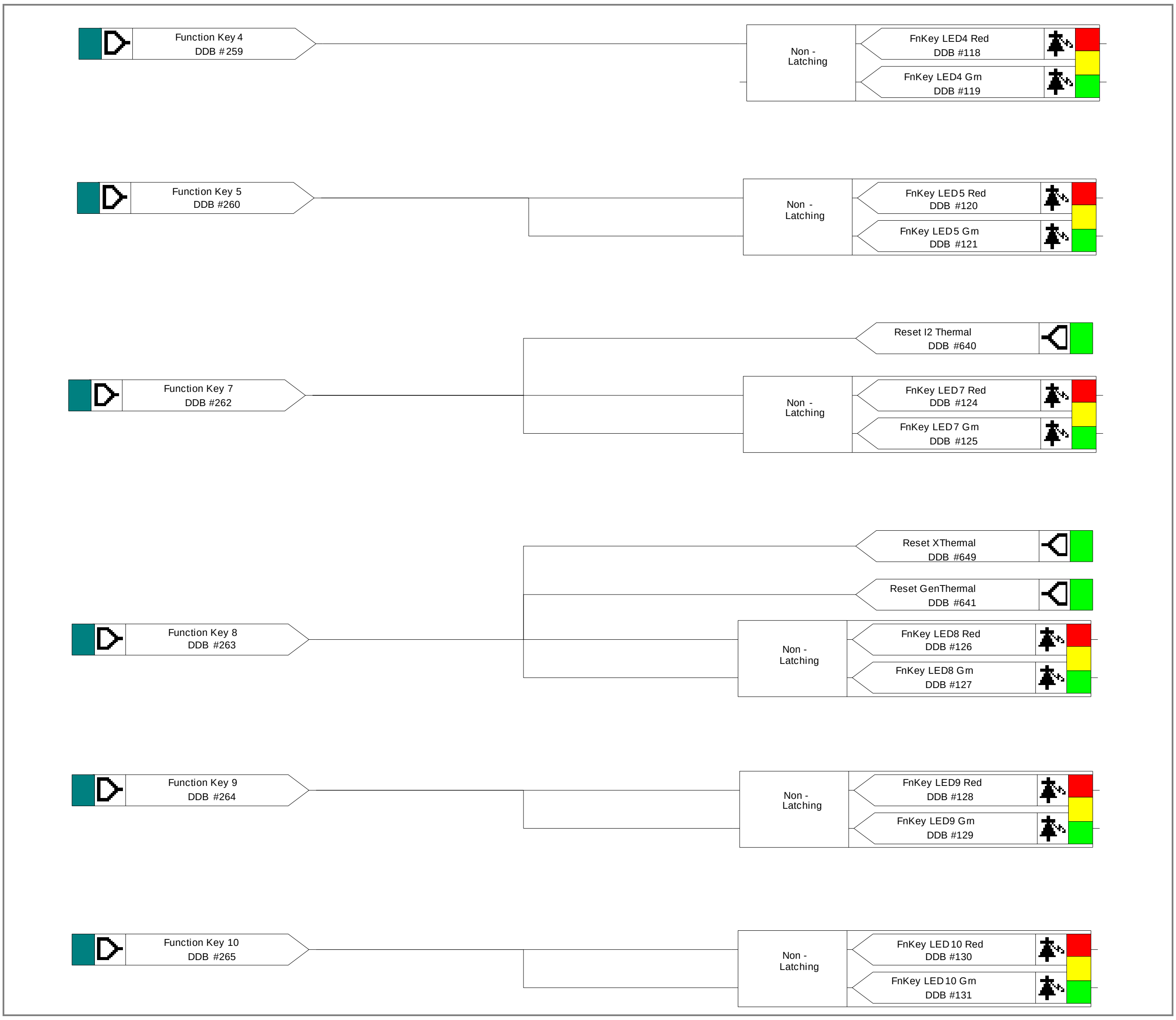

Figure 19 - Function key and LED mapping

6.5 Check Synch Mapping

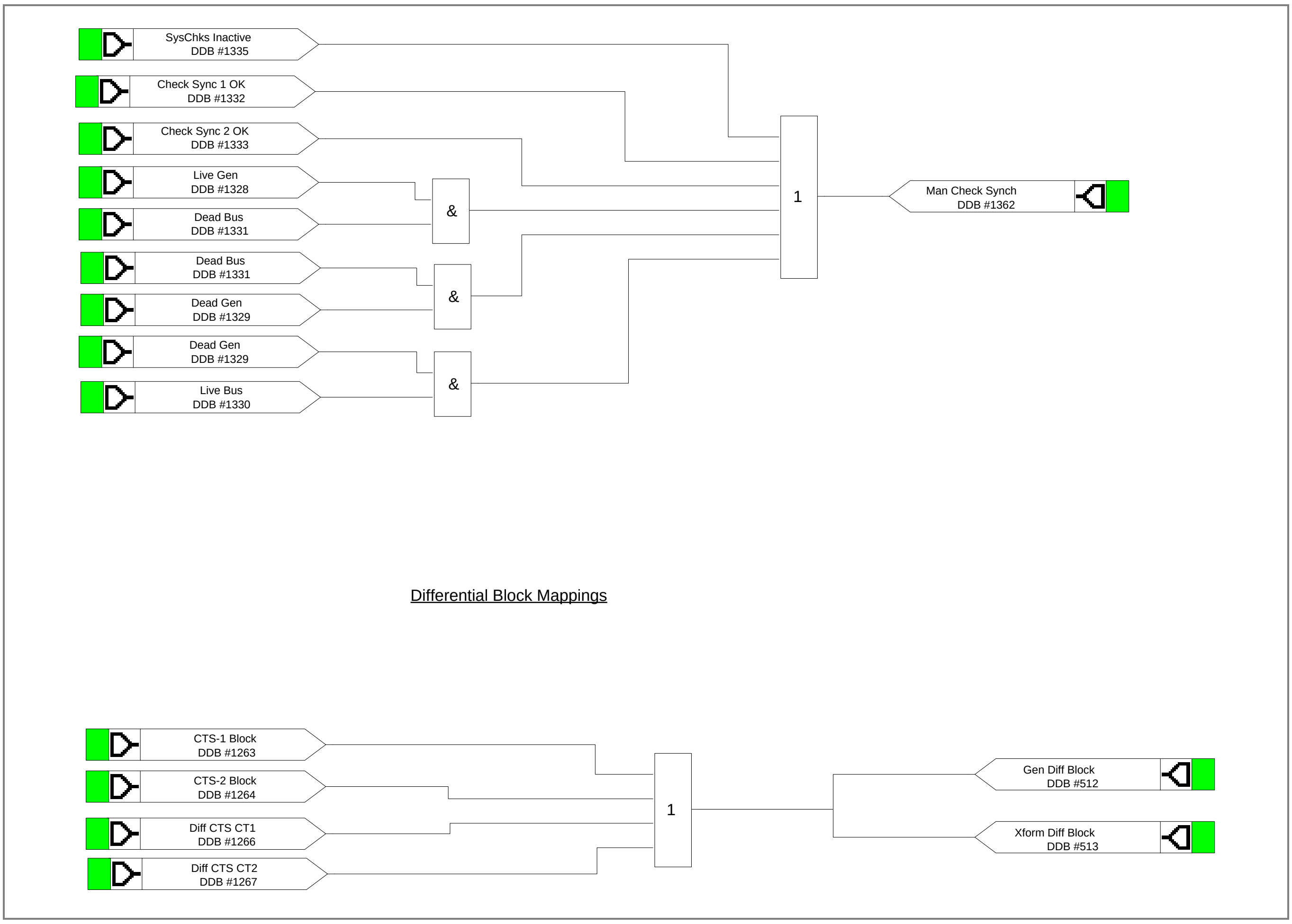

Figure 20 - Check synch and voltage monitor mapping

7 P344 PROGRAMMABLE SCHEME LOGIC

7.1 Input Mappings

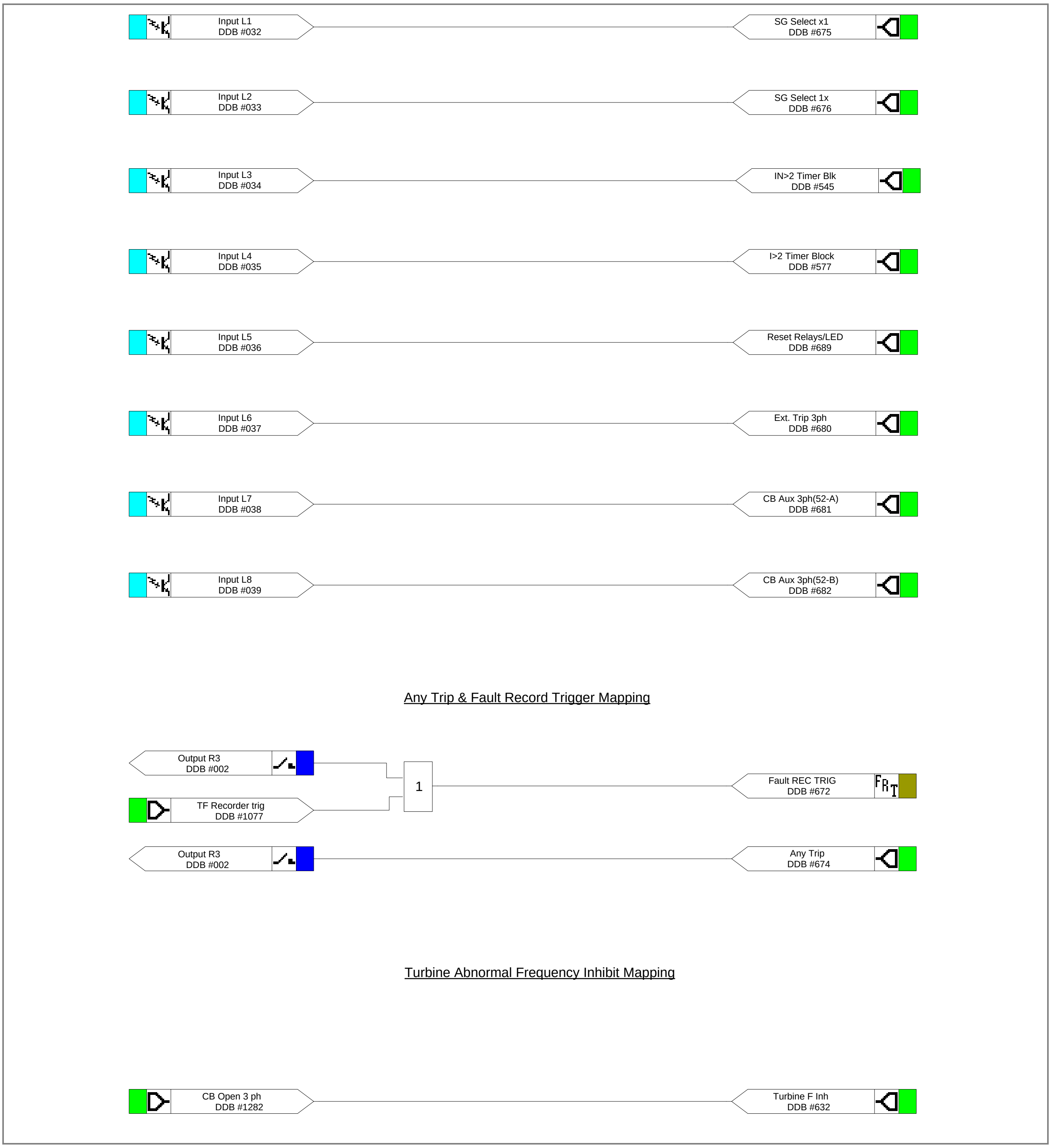

Figure 21 - Opto input mappings

7.2 Output Mappings

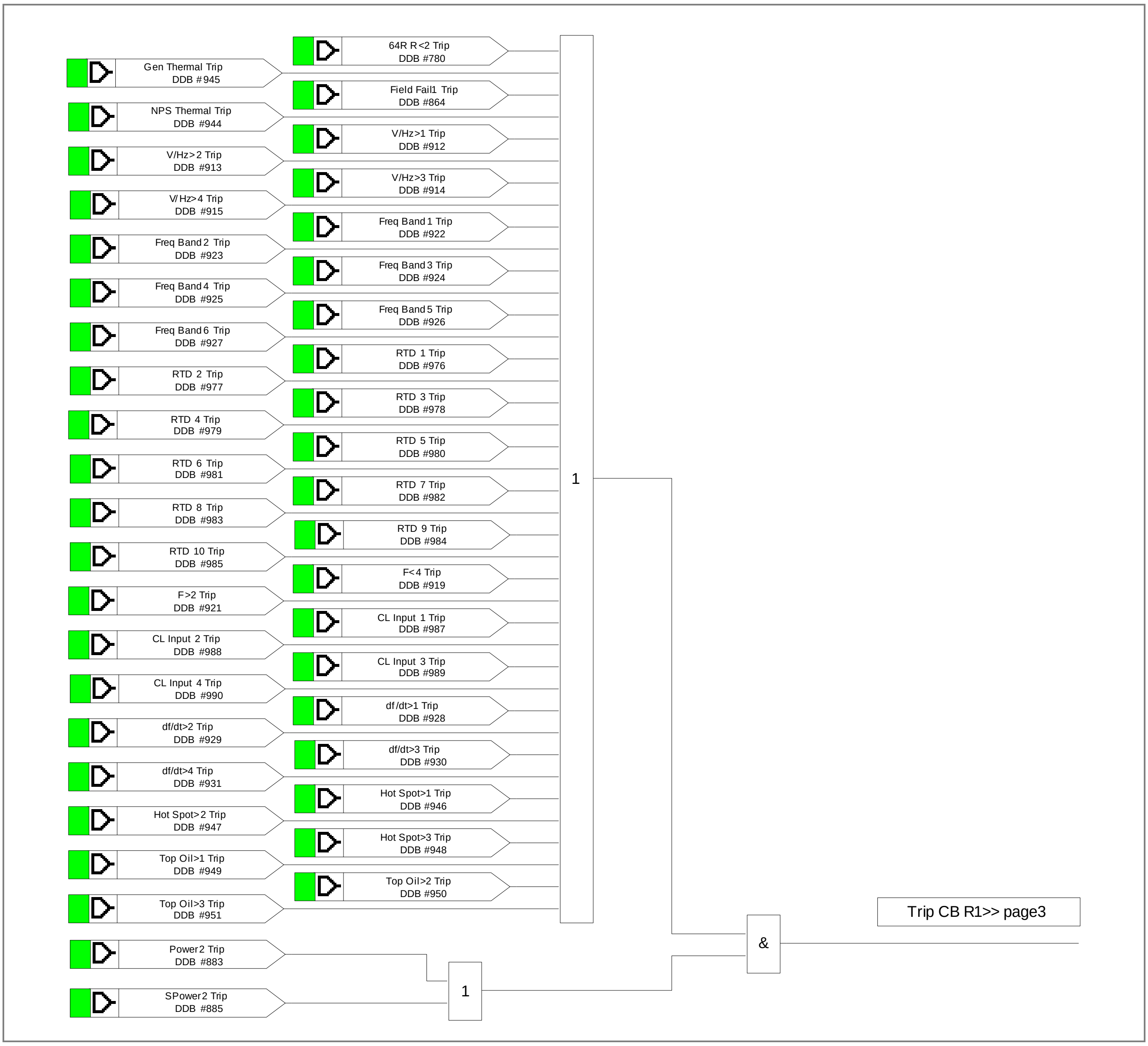

Figure 22 - Output relay R1 (Trip CB) mappings

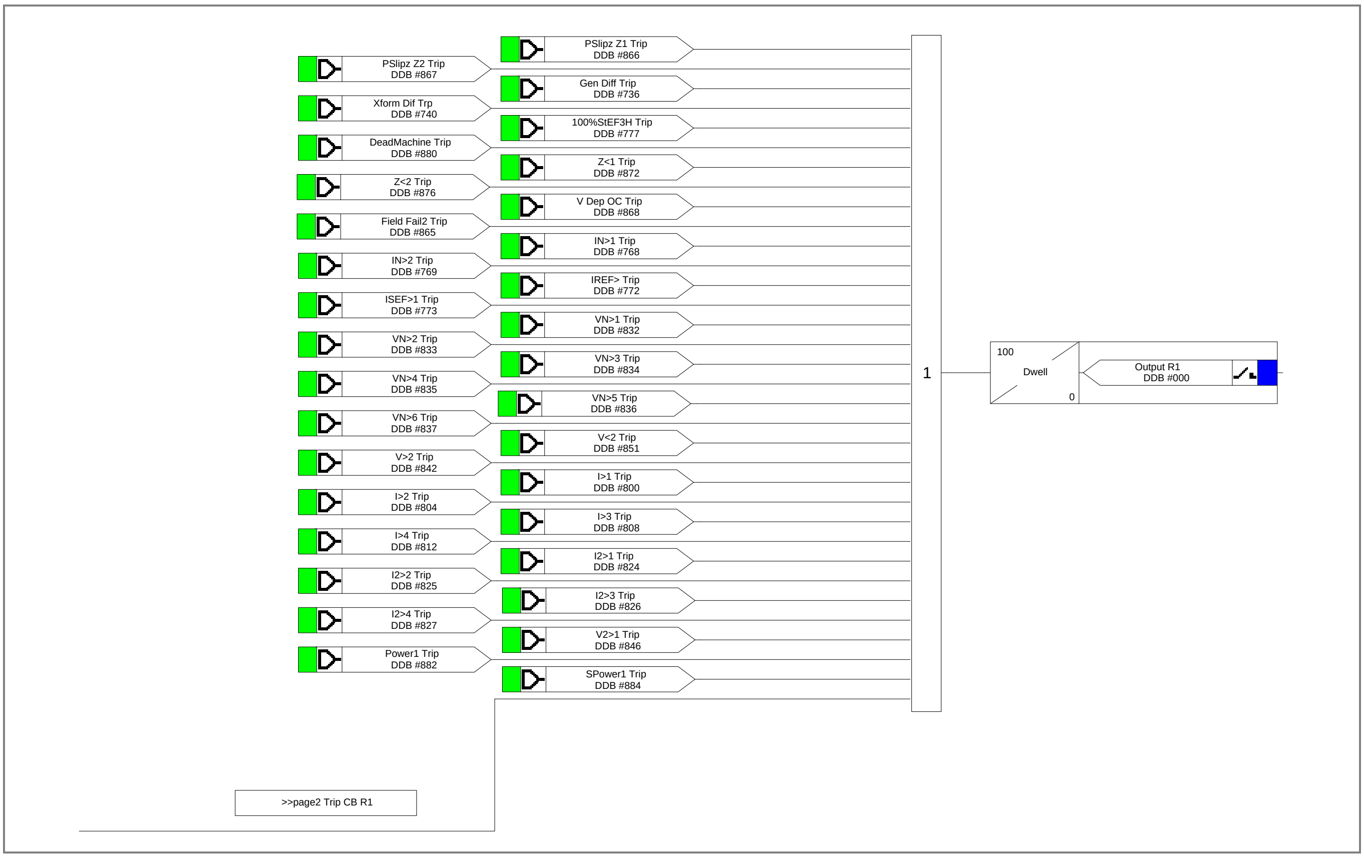

Figure 23 - Output relay R2 (Trip Prime Mover) mappings

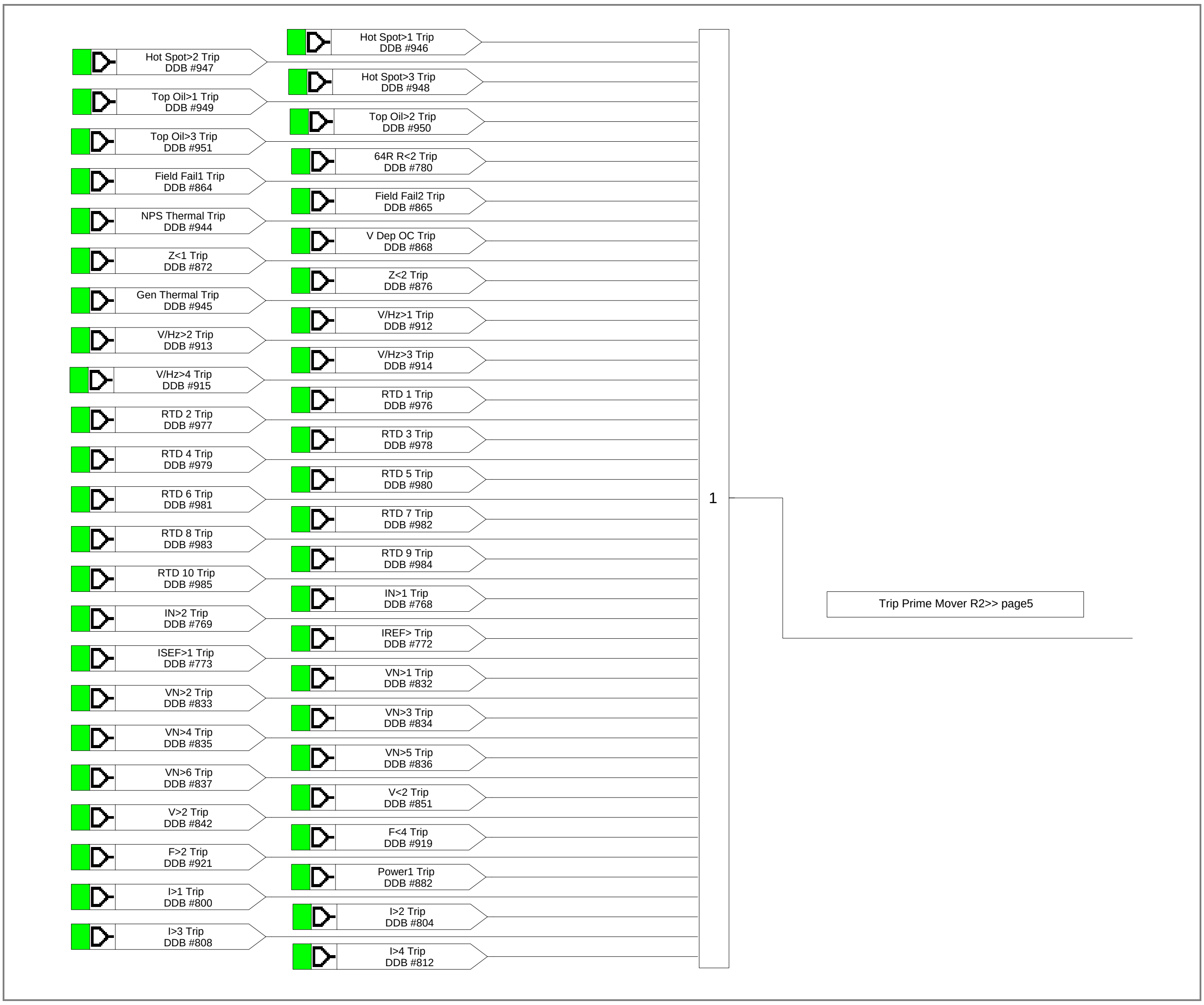

Figure 24 - Output relay R3 (Any Trip) mappings

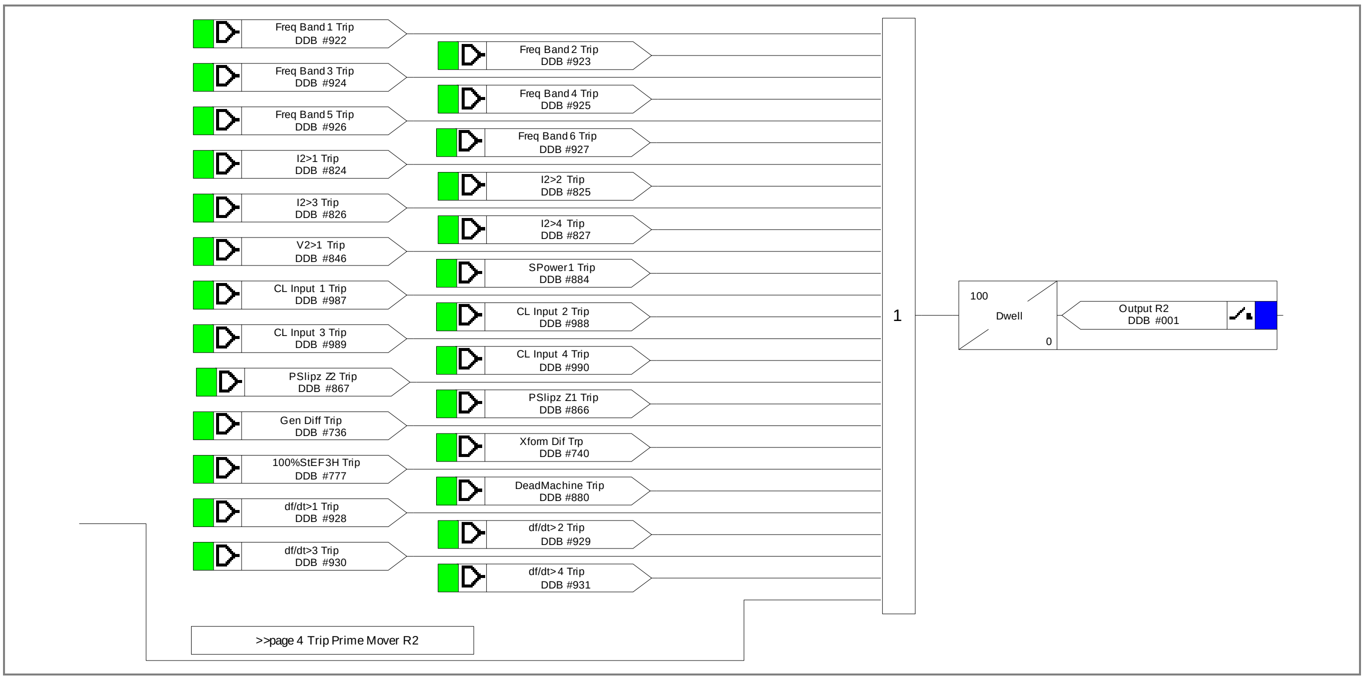

Figure 25 - Output relay R4 (General Alarm) mappings

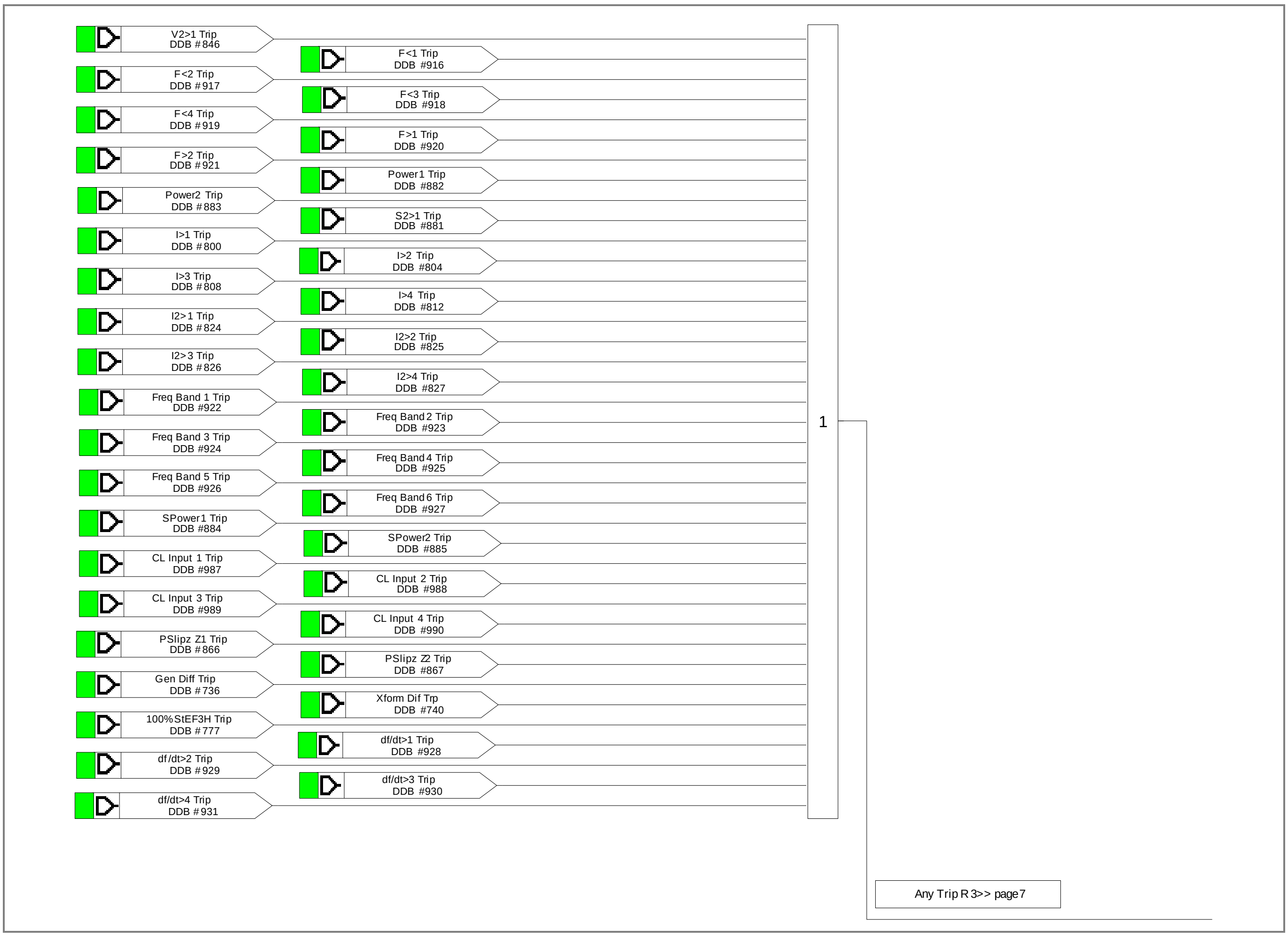

Figure 26 - Output relay R4 mappings

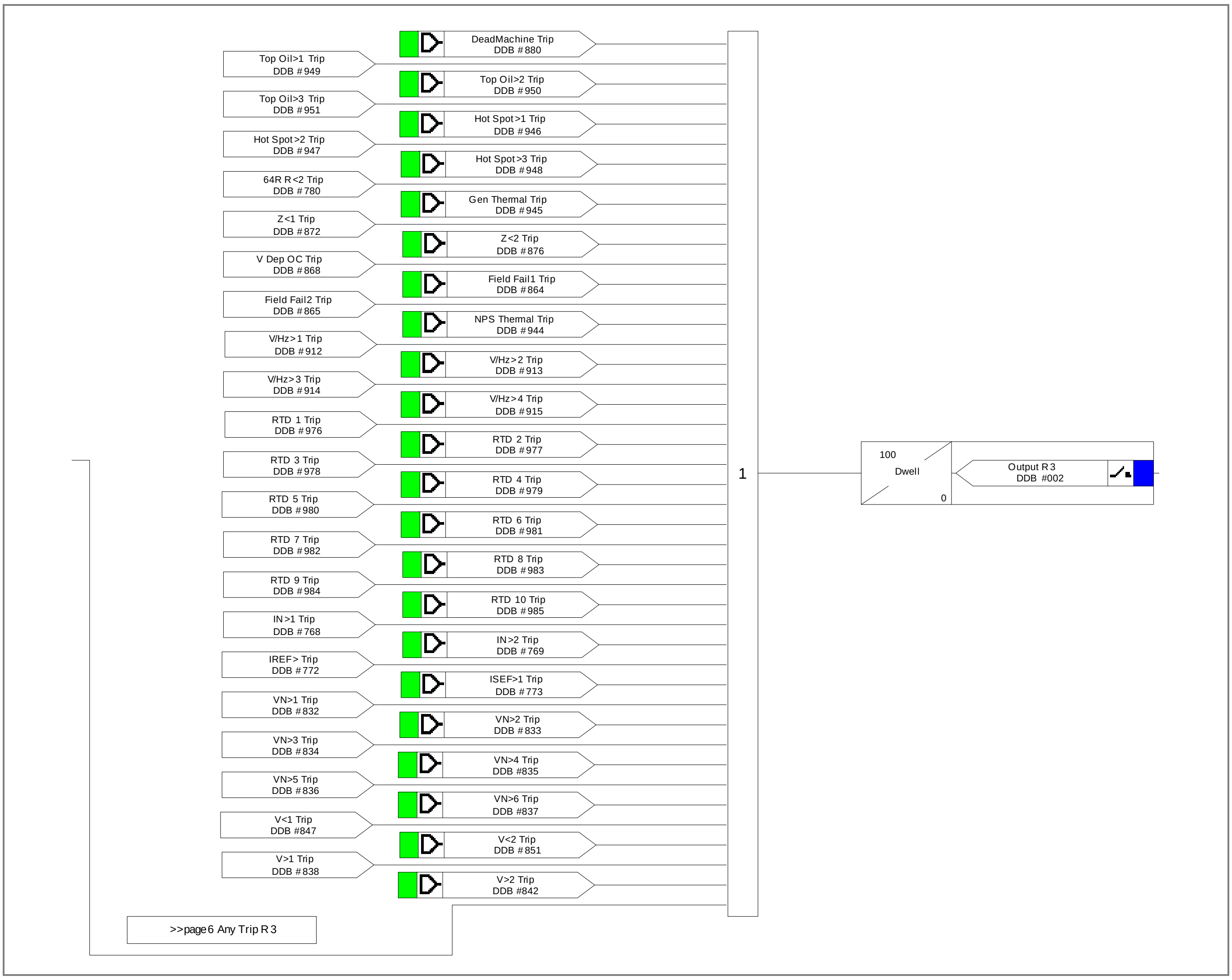

Figure 27 - Output relay mappings

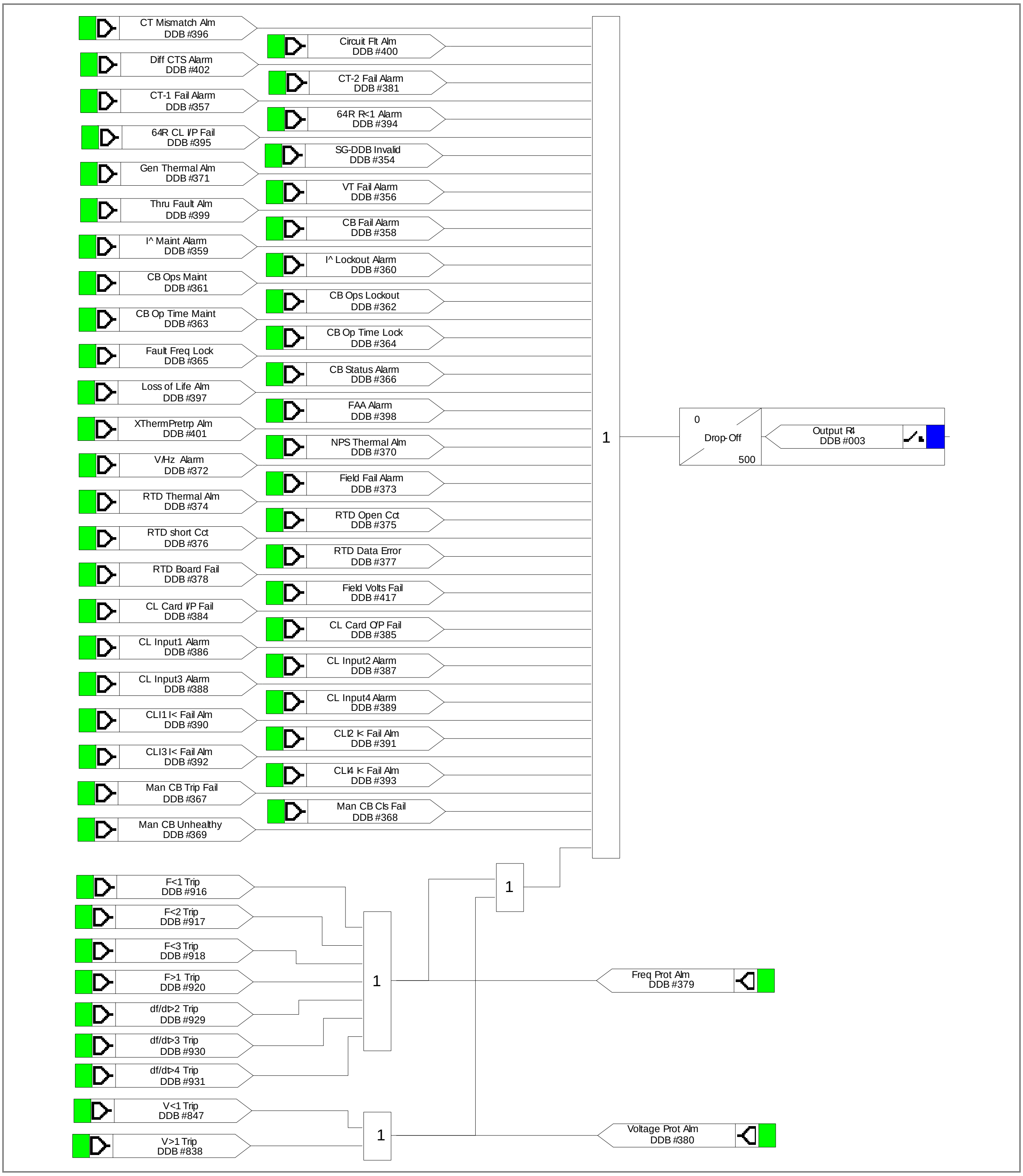

Figure 28 - Output relay mappings

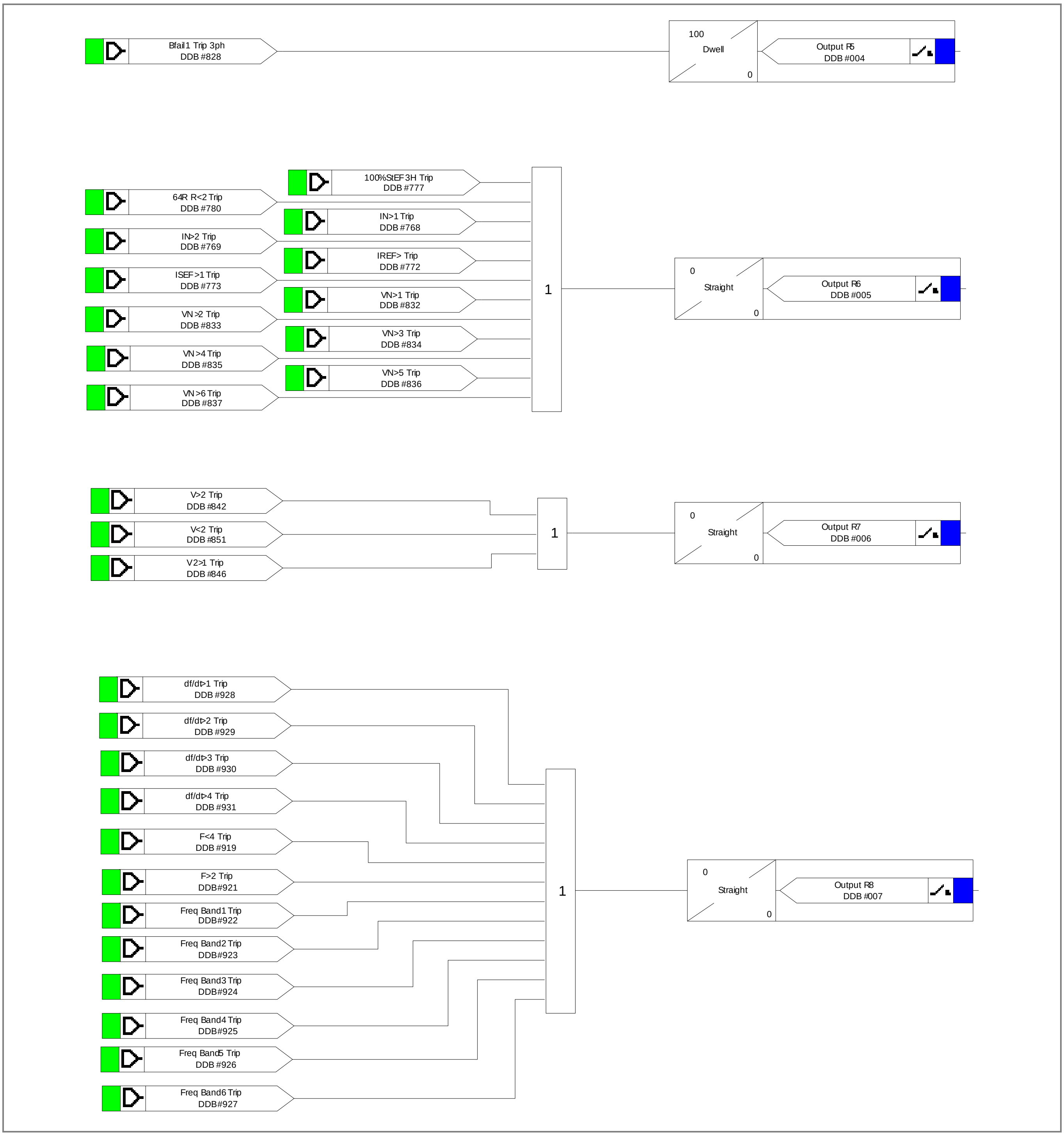

Figure 29 - Output relay mappings

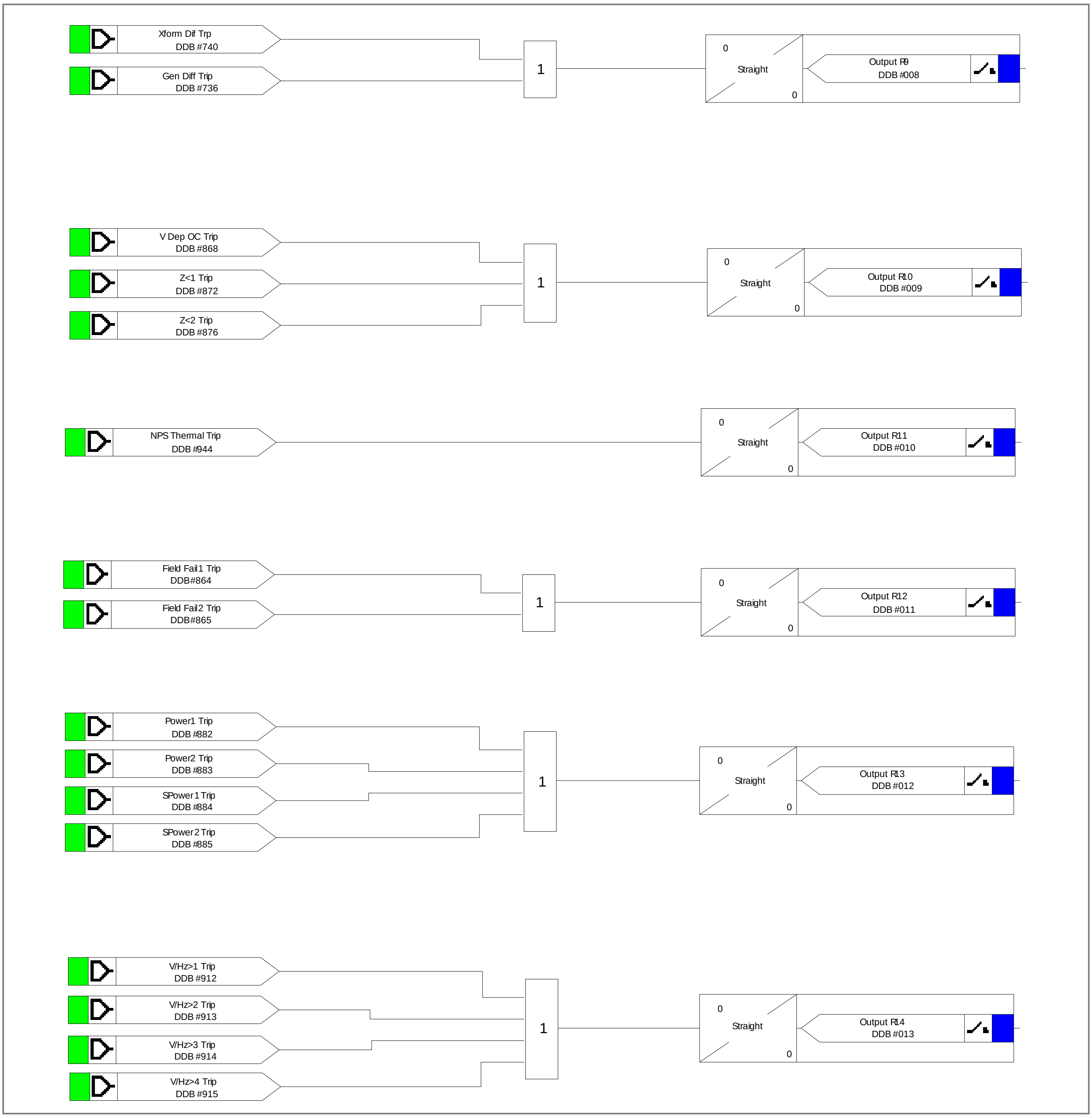

Figure 30 - Output relay mappings

7.3 Function and LED Mapping

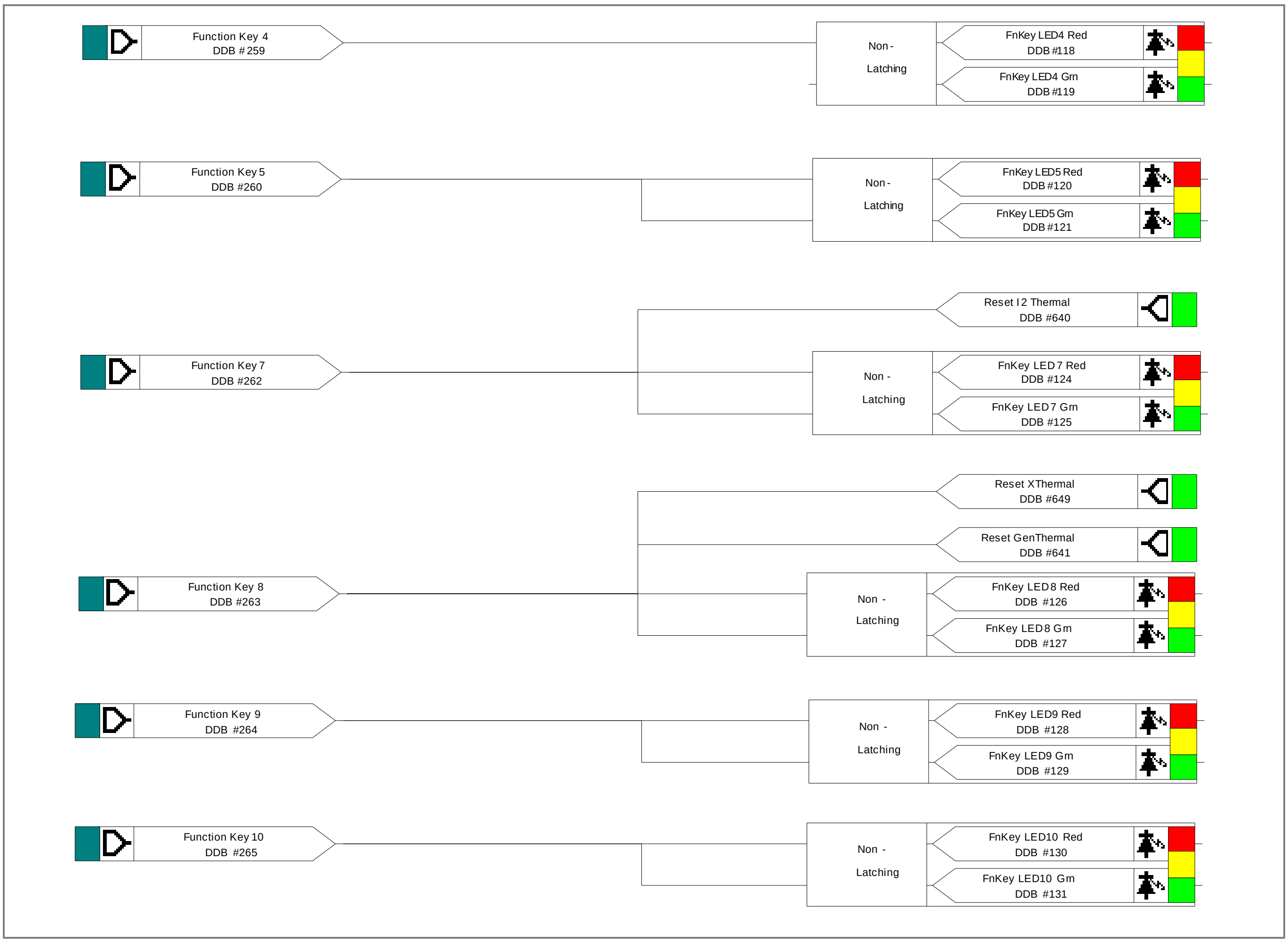

Figure 31 - Function key and function LED mapping

7.4 LED Mapping

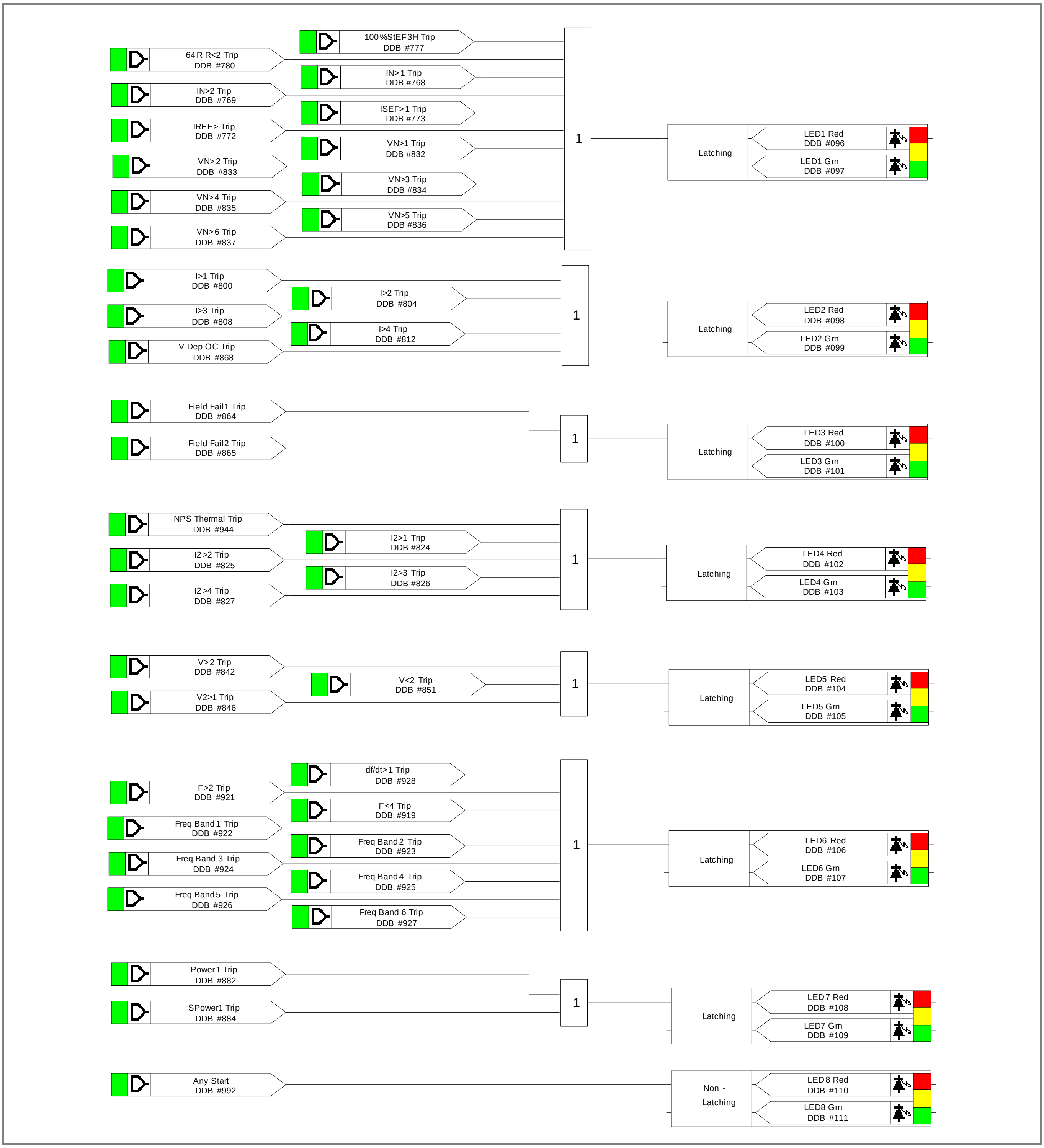

Figure 32 - LED output mapping

7.5 Check Synch Mapping

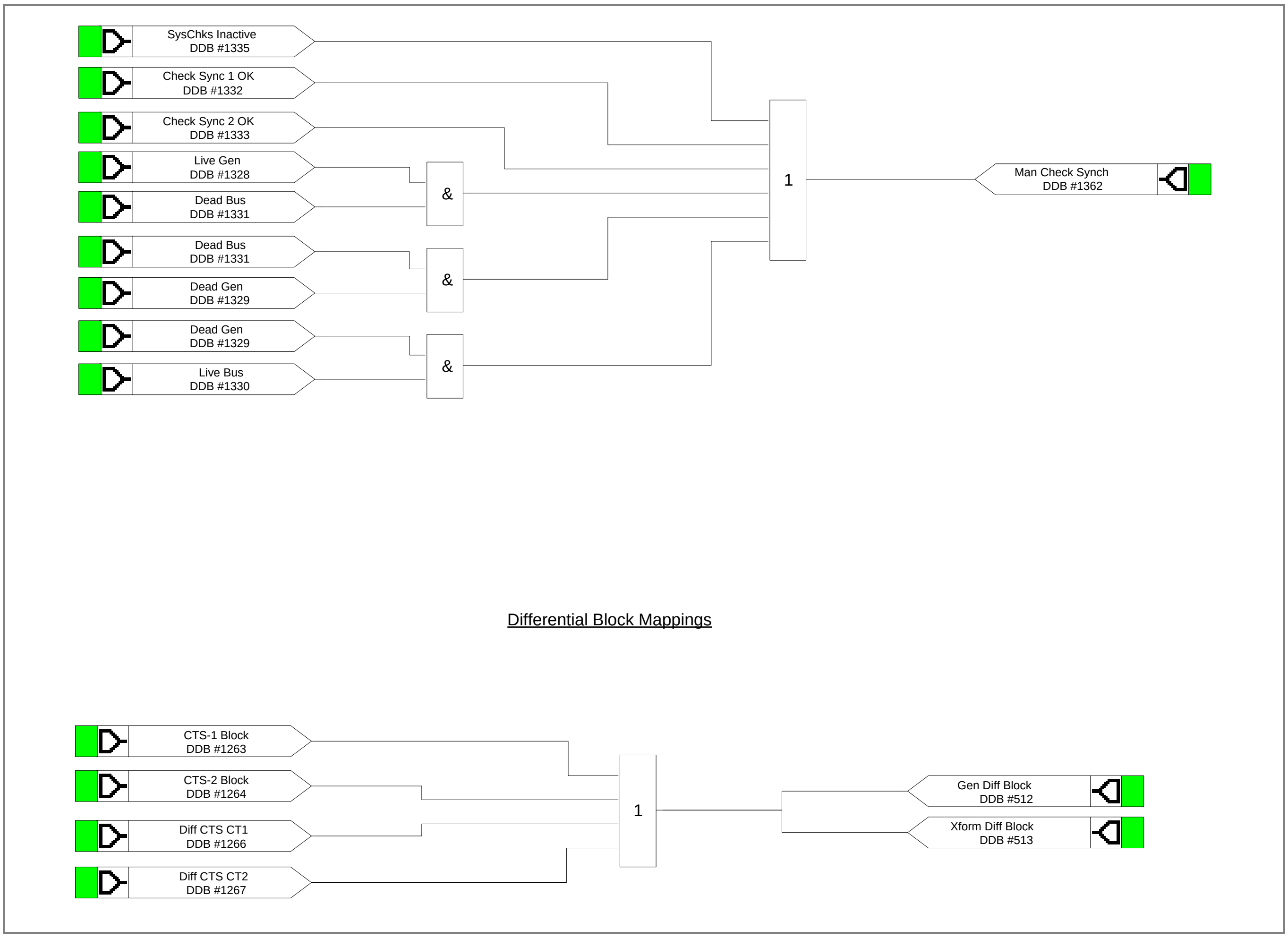

Figure 33 - Check synch and voltage monitor mapping

8 P345 PROGRAMMABLE SCHEME LOGIC

8.1 Input Mappings

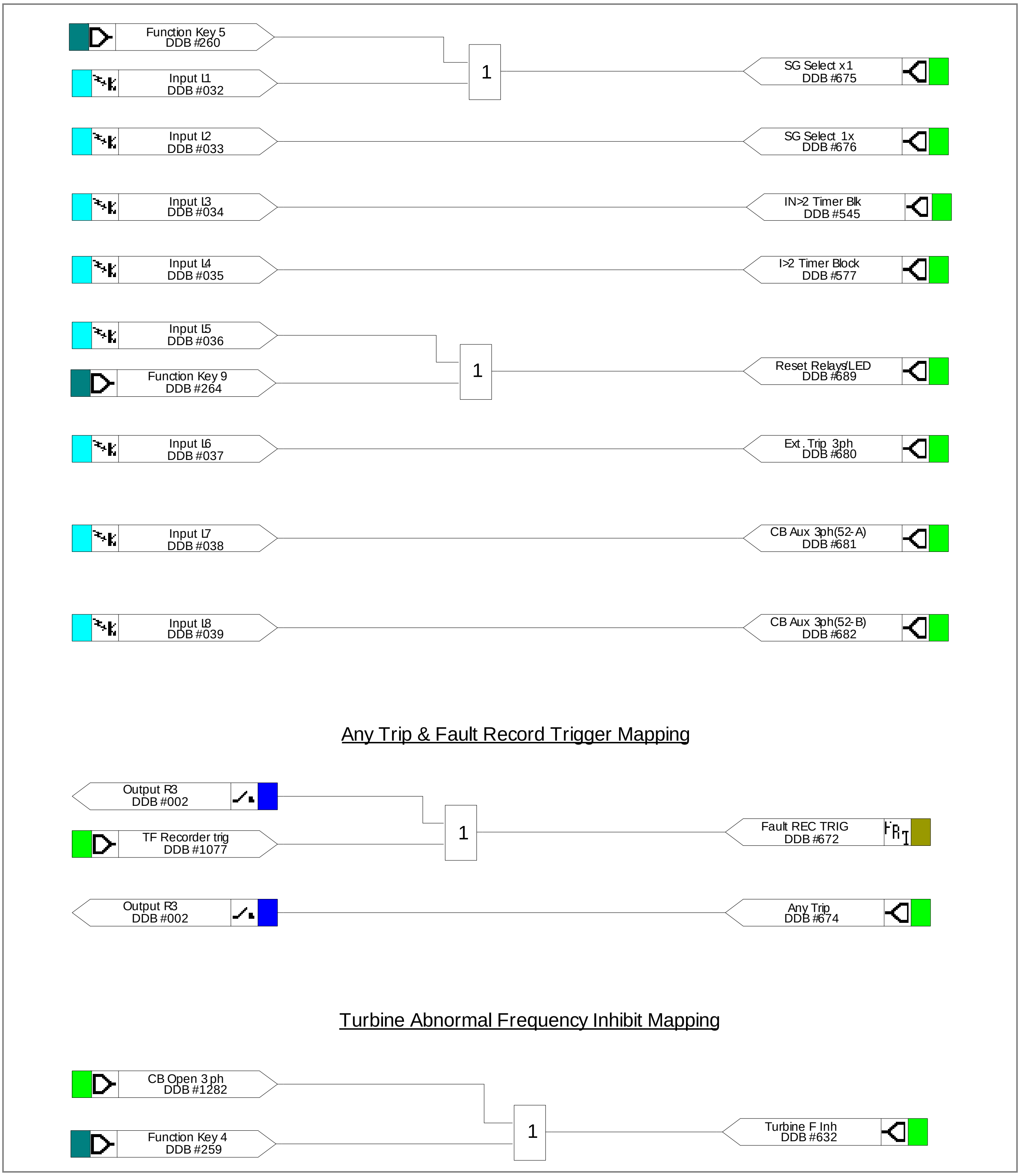

Figure 34 - Opto input mappings

8.2 Output Mappings

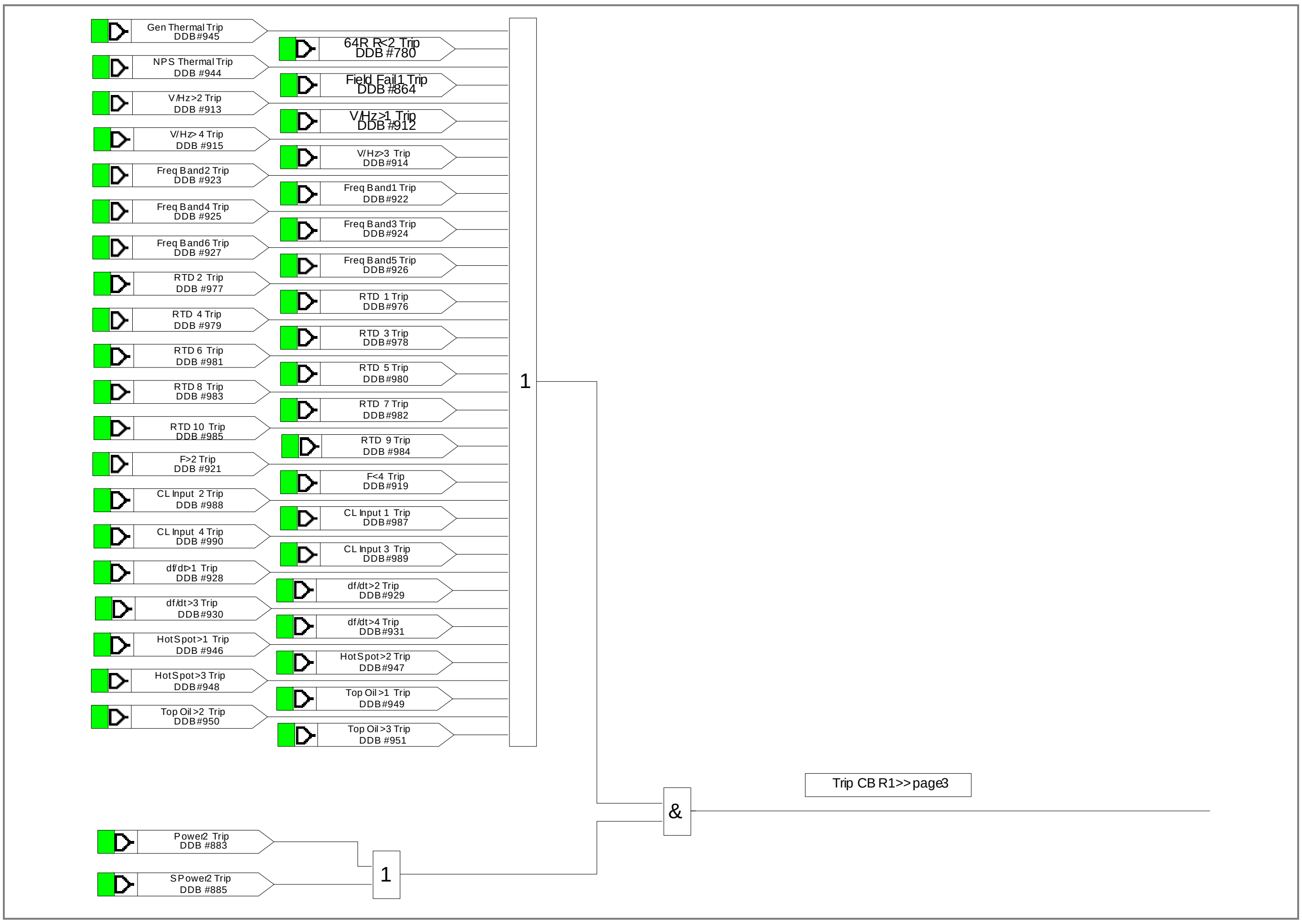

Figure 35 - Output relay R1 (Trip CB) mappings

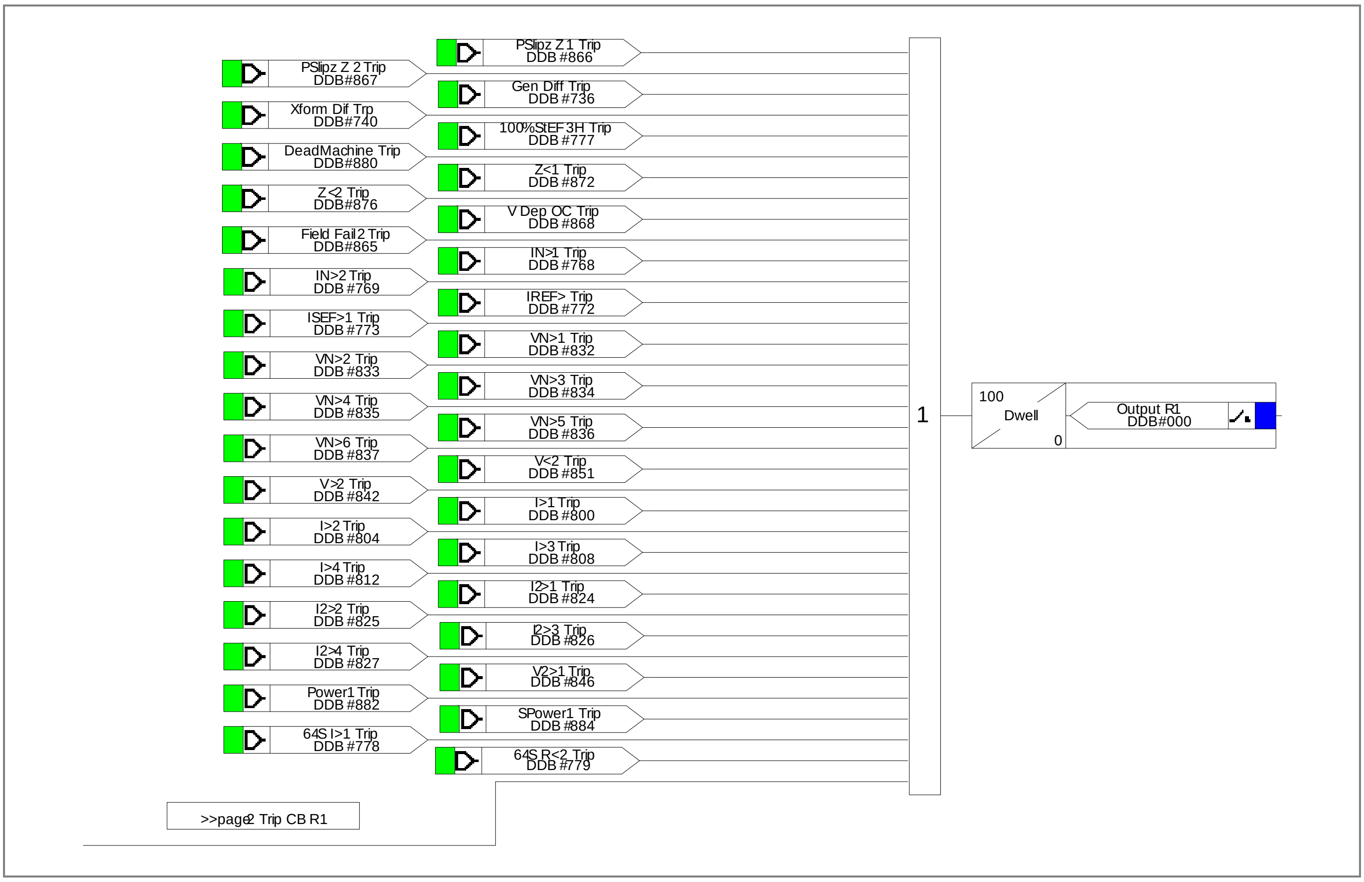

Figure 36 - Output relay R2 (Trip Prime Mover) mappings

Figure 37 - Output relay R3 (Any Trip) mappings

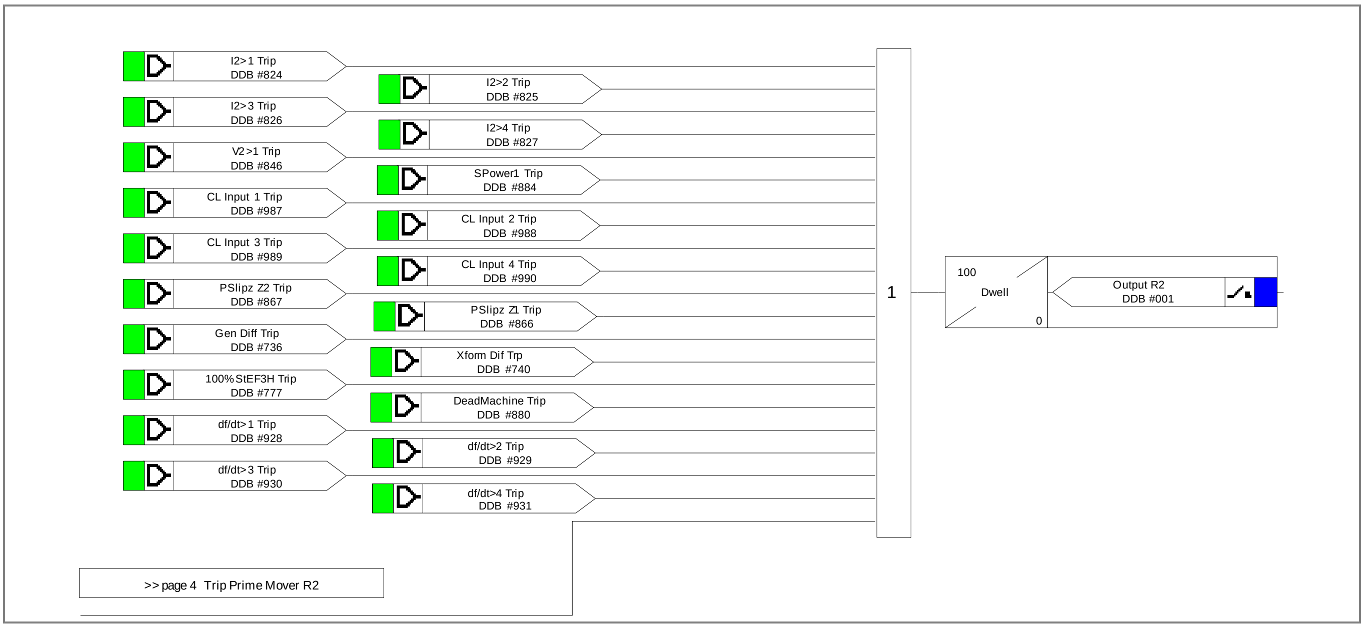

Figure 38 - Output relay R4 (General Alarm) mappings

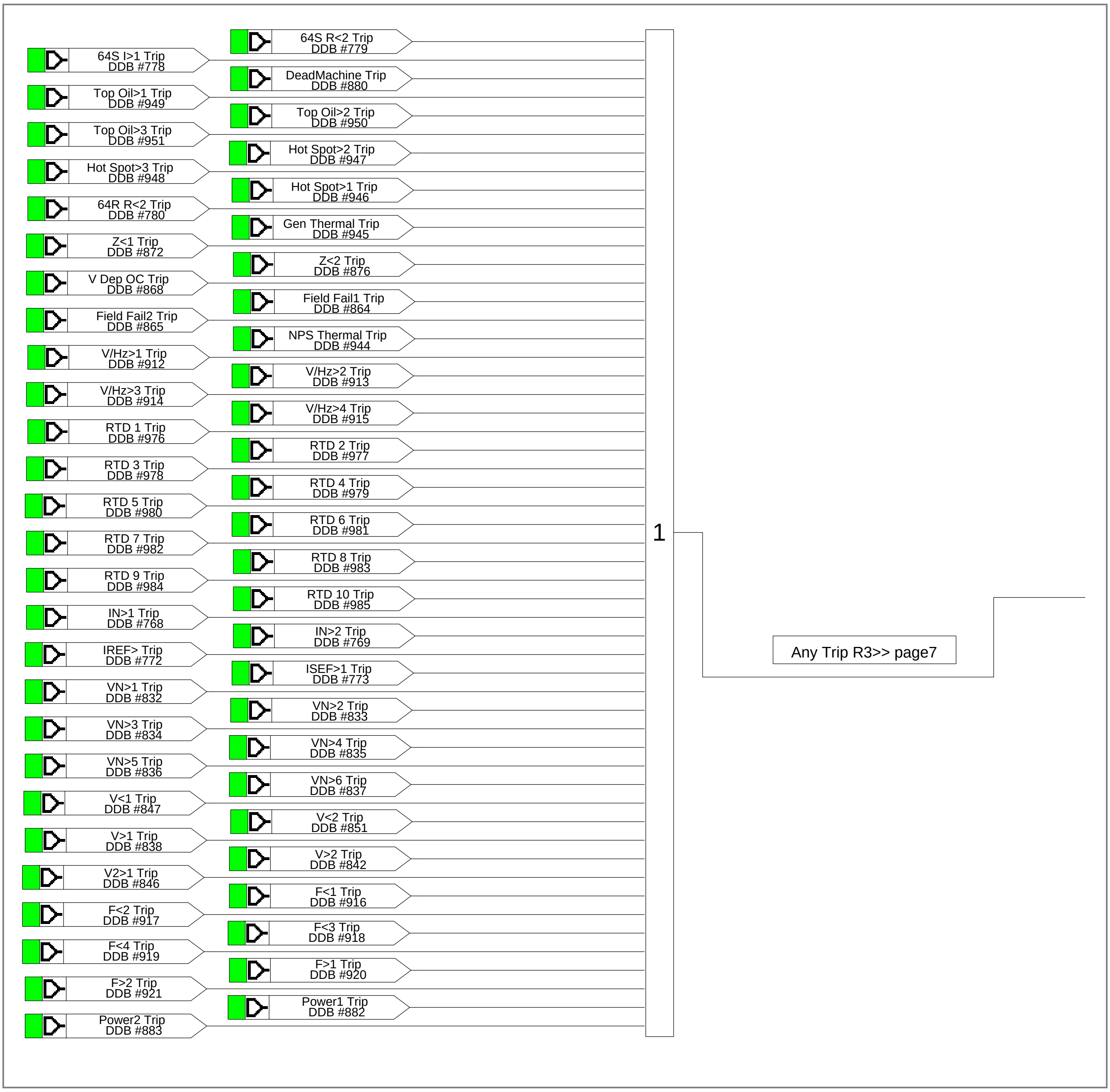

Figure 39 - Output relay mappings

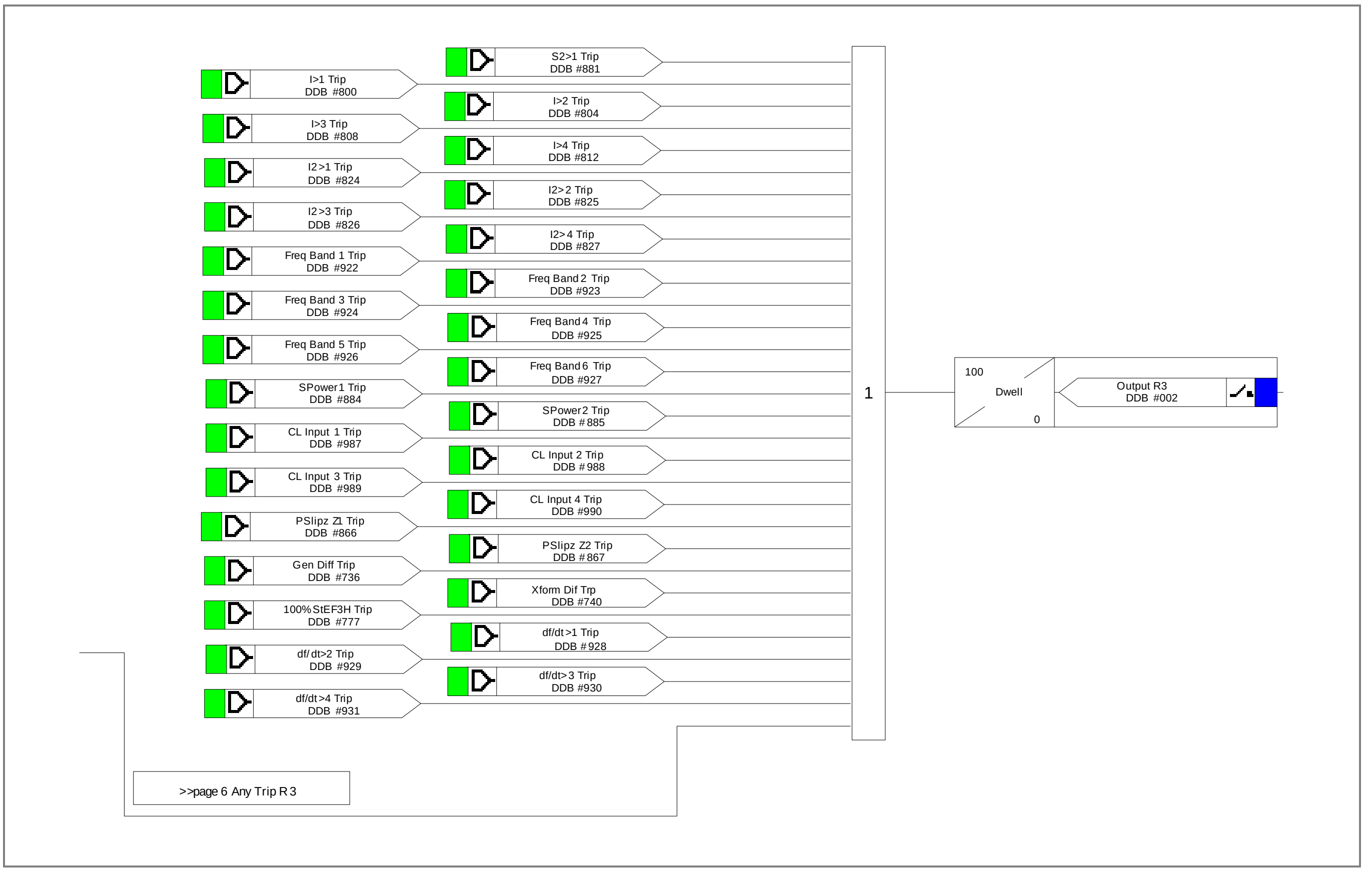

Figure 40 - Output relay mappings

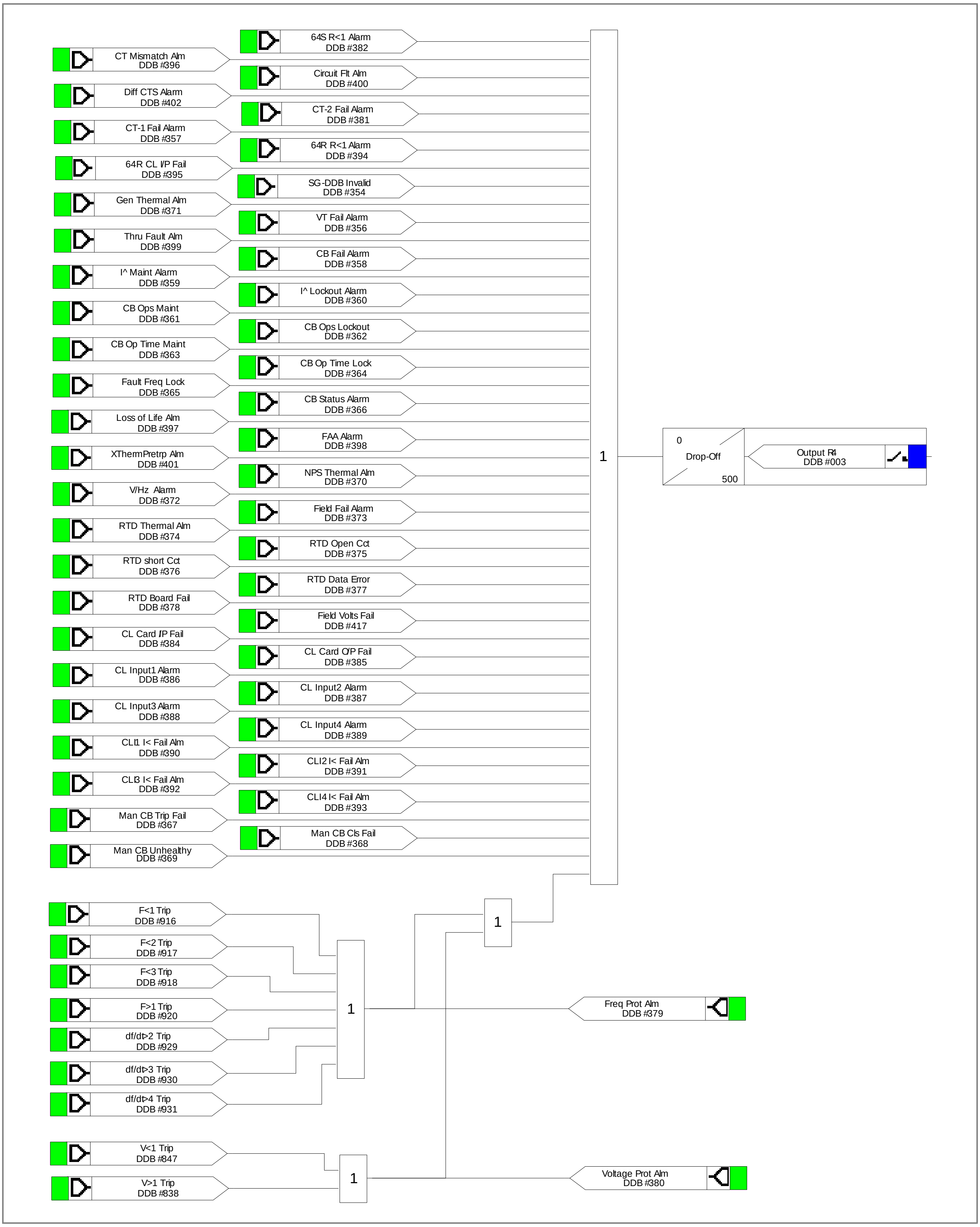

Figure 41 - Output relay mappings

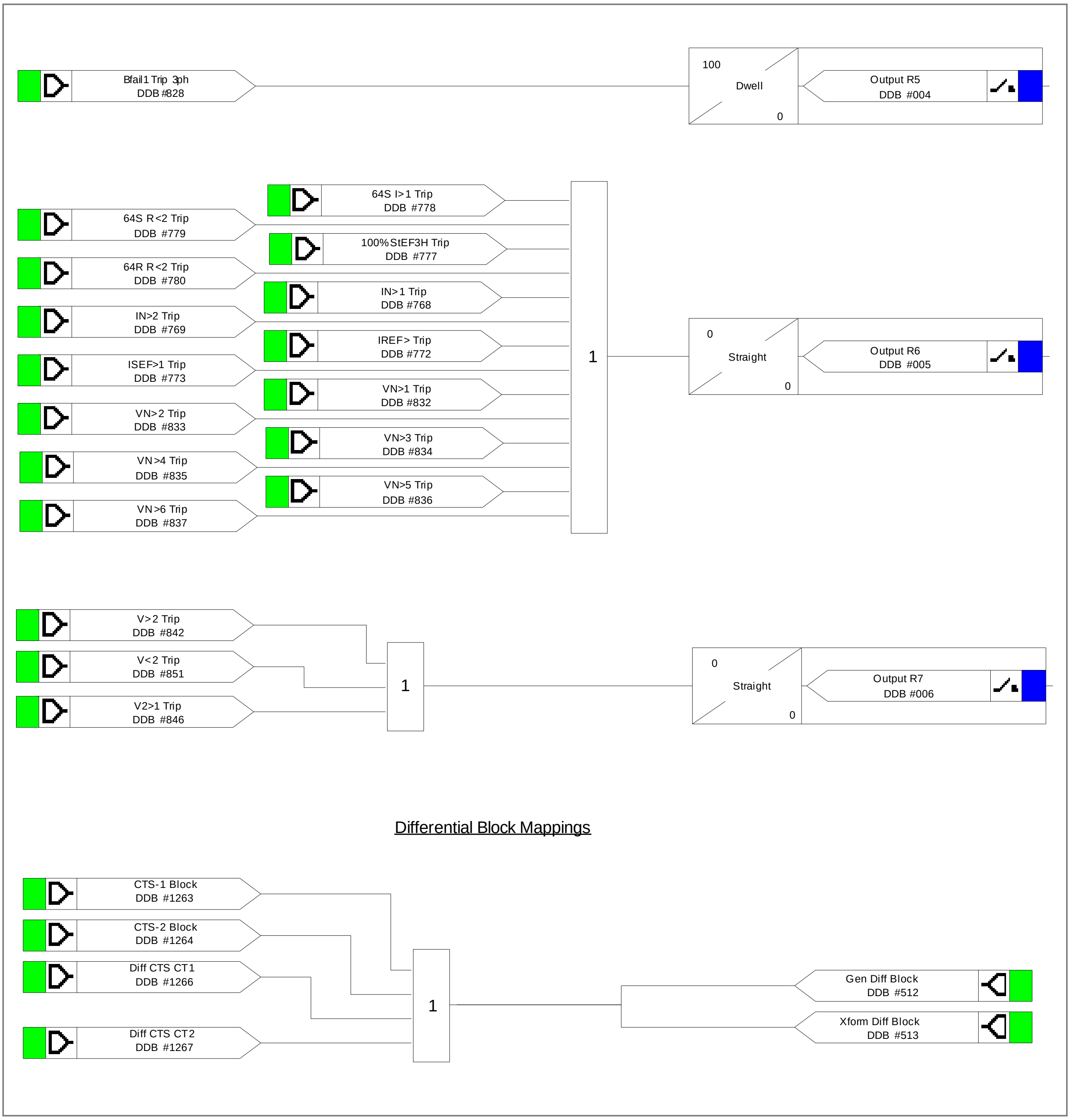

Figure 42 - Output relay mappings

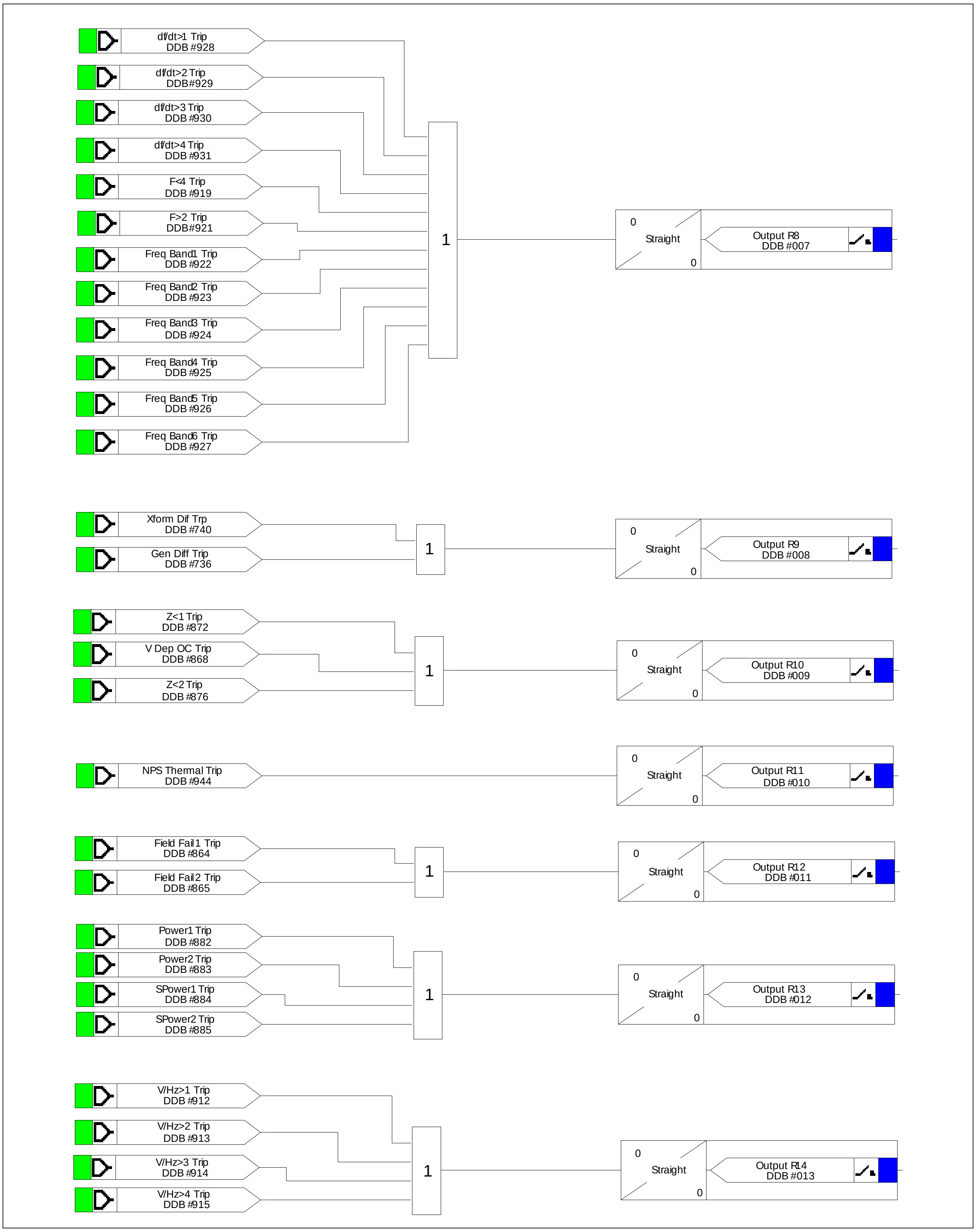

Figure 43 - Output relay mappings

8.3 Function and LED Mapping

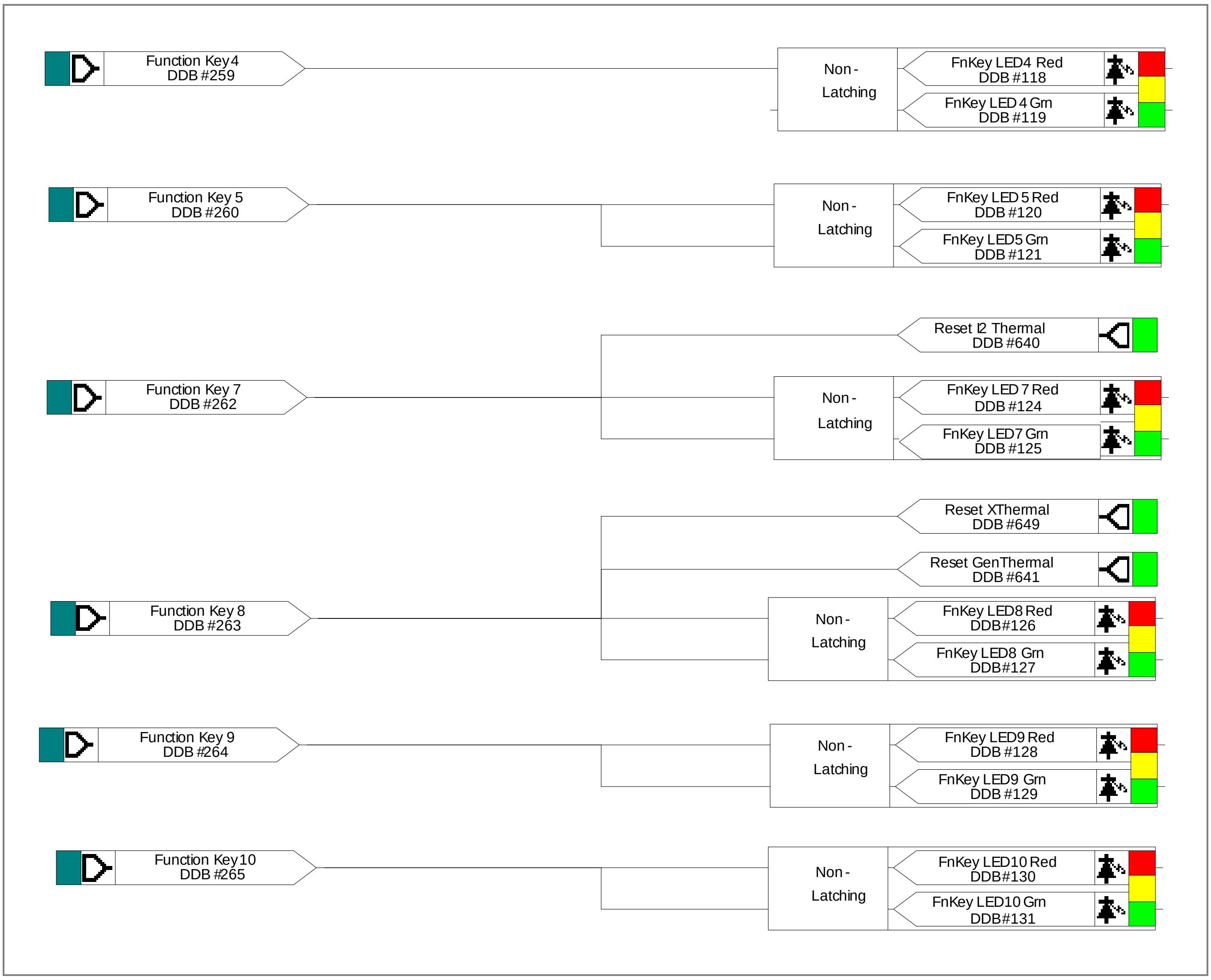

Figure 44 - Function key and function LED mapping

8.4 LED Mapping

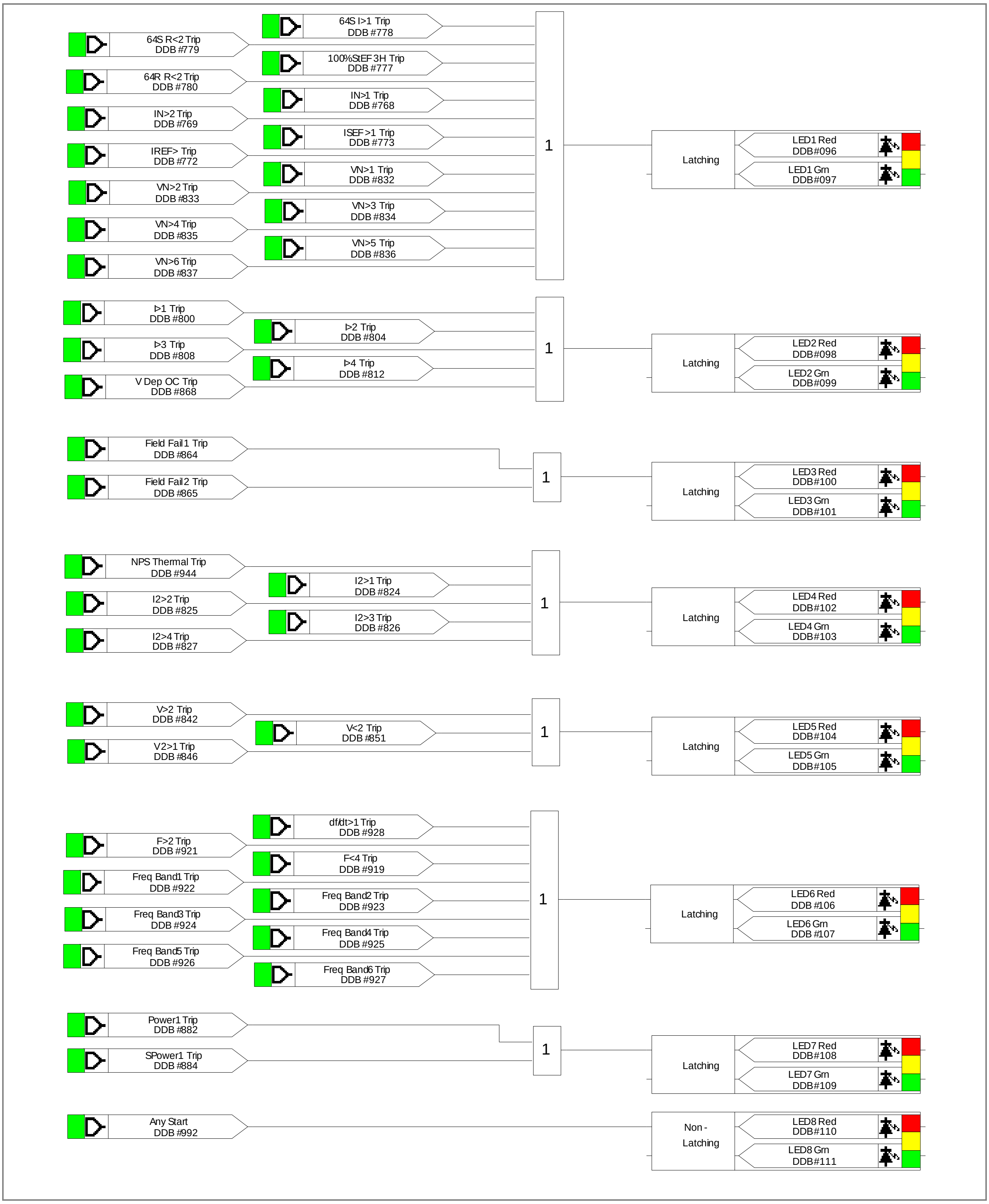

Figure 45 - LED output mapping

8.5 Check Synch Mapping

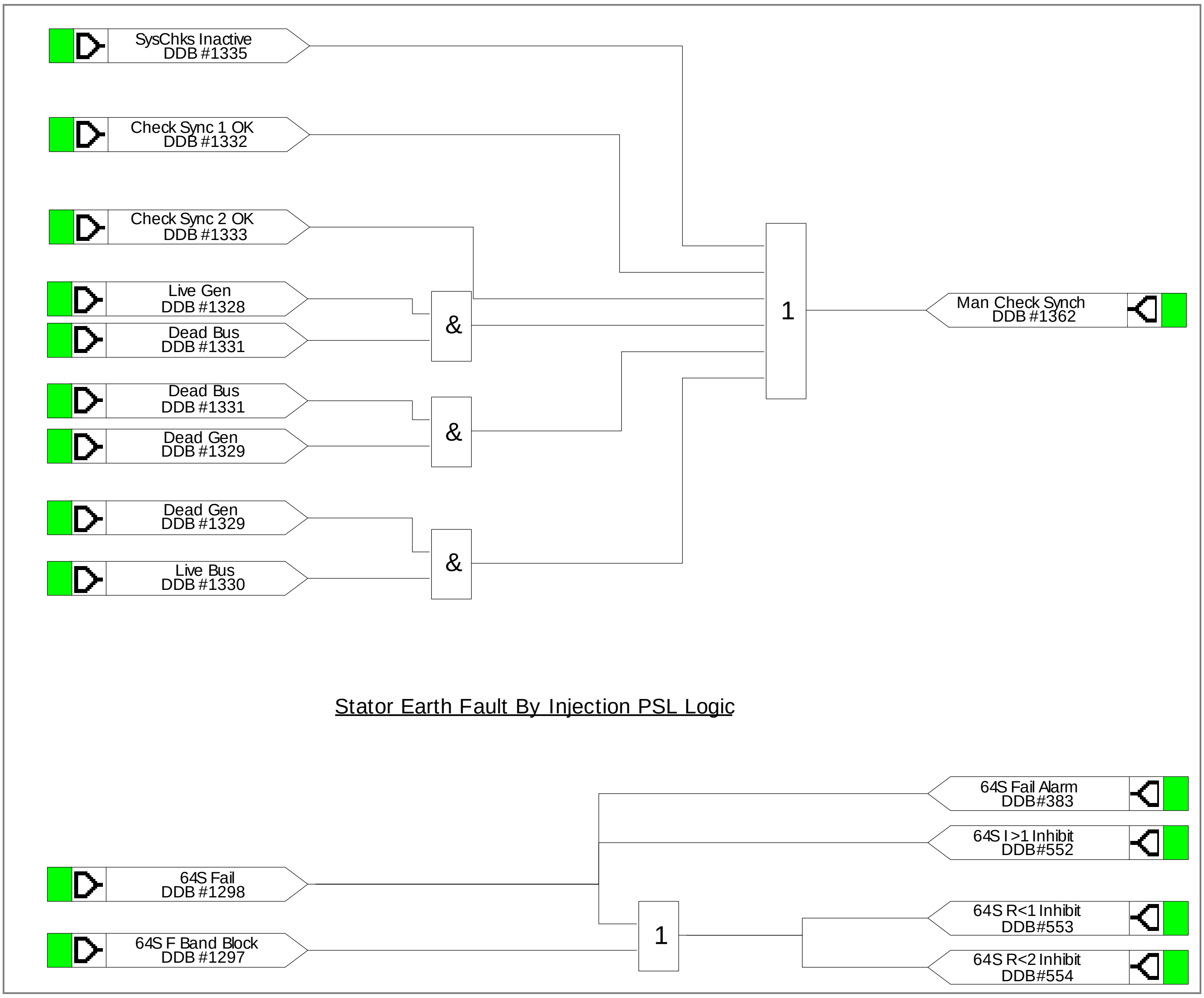

Figure 46 - Check synch and VOL monitor mapping

Notes:

MEASUREMENTS AND RECORDING

CHAPTER 9

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

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 AND 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.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
VIEW RECORDS	01	00		
This column contains event, fault and maintenance records				
Select Event	01	01	0	From 0 to 511 step 1
This selects the required event record from all the possible ones that may be stored. A value of 0 corresponds to the latest event, with the maximum value the oldest.				
Menu Cell Ref	01	02		Not Settable
Indicates type of event.				
Time & Date	01	03		Not Settable
Time & Date Stamp for the event given by the internal Real Time Clock.				
Event Text	01	04		Not Settable
Up to 16 Character description of the Event (refer to following sections).				
Event Value	01	05		Not Settable
Up to 32 Bit Binary Flag or integer representative of the Event (refer to following sections).				
Select Fault	01	06	0	From 0 to 20 step 1
This selects the required fault record from the possible 20 that may be stored. A value of 0 corresponds to the latest fault and so on.				
Faulted Phase	01	40		Not Settable
Phase initiating fault recorder starts : Start A, Start B, Start C, Trip A, Trip B, Trip C.				
Start Elements1	01	42		Not Settable
Displays the status of the first 32 start signals				
Start Elements2	01	43		Not Settable
Displays the status of the second 32 start signals				
Start Elements3	01	44		Not Settable
Displays the status of the third 32 start signals				
Start Elements4	01	45		Not Settable
Displays the status of the fourth 32 start signals				
Trip Elements1	01	49		Not Settable
Displays the status of the first 32 trip signals				
Trip Elements2	01	4A		Not Settable
Displays the status of the second 32 trip signals				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Trip Elements3	01	4B		Not Settable
Displays the status of the third 32 trip signals				
Trip Elements4	01	4C		Not Settable
Displays the status of the fouth 32 trip signals				
Fault Alarms	01	50		Not Settable
Displays the status of the first 32 fault alarm signals				
Fault Alarms 2	01	51		Not Settable
Displays the status of the second 32 fault alarm signals				
Fault Time	01	55		Not Settable
Displays fault time and date				
Active Group	01	57		Not Settable
Displays active setting group				
System Frequency	01	59		Not Settable
Displays the system frequency				
Fault Duration	01	5B		Not Settable
Displays time from the start or trip until the undercurrent elements indicate the CB is open				
CB Operate Time	01	5E		Not Settable
Displays time from protection trip to undercurrent elements indicating the CB is open				
Relay Trip Time	01	60		Not Settable
Displays time from protection start to protection trip				
IA IA-1	01	62		Not Settable
CT1 Phase A Magnitude				
IB IB-1	01	63		Not Settable
CT1 Phase B Magnitude				
IC IC-1	01	64		Not Settable
CT1 Phase C Magnitude				
VAB	01	65		Not Settable
Phase A to Phase B voltage Magnitude				
VBC	01	66		Not Settable
Phase B to Phase C voltage Magnitude				
VCA	01	67		Not Settable
Phase C to Phase A voltage Magnitude				
VAN	01	68		Not Settable
Phase A to Neutral Voltage Magnitude				
VBN	01	69		Not Settable
Phase B to Neutral Voltage Magnitude				
VCN	01	6A		Not Settable
Phase C to Neutral Voltage Magnitude				
IA-2	01	70		Not Settable
CT2 Phase A Magnitude				
IB-2	01	71		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CT2 Phase B Magnitude				
IC-2	01	72		Not Settable
CT2 Phase C Magnitude				
IA Differential	01	80		Not Settable
Phase A Differential Current				
IB Differential	01	81		Not Settable
Phase B Differential Current				
IC Differential	01	82		Not Settable
Phase C Differential Current				
IA Diff PU	01	83		Not Settable
Phase A Differential PU Current				
IB Diff PU	01	84		Not Settable
Phase B Differential PU Current				
IC Diff PU	01	85		Not Settable
Phase C Differential PU Current				
IA Diff 2H	01	86		Not Settable
Phase A 2nd Harmonic Differential Current				
IB Diff 2H	01	87		Not Settable
Phase B 2nd Harmonic Differential Current				
IC Diff 2H	01	88		Not Settable
Phase C 2nd Harmonic Differential Current				
IA Diff 5H	01	89		Not Settable
Phase A 5th Harmonic Differential Current				
IB Diff 5H	01	8A		Not Settable
Phase B 5th Harmonic Differential Current				
IC Diff 5H	01	8B		Not Settable
Phase C 5th Harmonic Differential Current				
VN Measured VN1 Measured	01	90		Not Settable
Measured Neutral Voltage Magnitude				
VN2 Measured	01	92		Not Settable
VN2 Measured Neutral Voltage Magnitude				
VN Derived	01	94		Not Settable
Derived Neutral Voltage Magnitude				
IN Measured IN Derived	01	96		Not Settable
Neutral Derived Current Magnitude (P341) Neutral Measured Current Magnitude (P34x)				
I Sensitive	01	99		Not Settable
Sensitive CT Current Magnitude				
IREF Diff	01	9C		Not Settable
Referenced Differential Current				
IREF Bias	01	9D		Not Settable
Referenced Bias Current				
I2	01	A0		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Negative Sequence Current				
V2	01	A2		Not Settable
Negative Sequence Voltage				
3 Phase Watts	01	A6		Not Settable
3 Phase Active Power				
3 Phase VArs	01	A8		Not Settable
3 Phase VArs measurement				
3Ph Power Factor	01	AA		Not Settable
3 Phase Power Factor				
RTD 1	01	B0		Not Settable
RTD 1 Temperature				
RTD 2	01	B1		Not Settable
RTD 2 Temperature				
RTD 3	01	B2		Not Settable
RTD 3 Temperature				
RTD 4	01	B3		Not Settable
RTD 4 Temperature				
RTD 5	01	B4		Not Settable
RTD 5 Temperature				
RTD 6	01	B5		Not Settable
RTD 6 Temperature				
RTD 7	01	B6		Not Settable
RTD 7 Temperature				
RTD 8	01	B7		Not Settable
RTD 8 Temperature				
RTD 9	01	B8		Not Settable
RTD 9 Temperature				
RTD 10	01	B9		Not Settable
RTD 10 Temperature				
df/dt	01	C2		Not Settable
df/dt Value				
V Vector Shift	01	C4		Not Settable
Voltage Vector Shift Value				
CLIO Input 1	01	C6		Not Settable
CLIO Input 1				
CLIO Input 2	01	C7		Not Settable
CLIO Input 2				
CLIO Input 3	01	C8		Not Settable
CLIO Input 3				
CLIO Input 4	01	C9		Not Settable
CLIO Input 4				
64S V Magnitude	01	CA		Not Settable
100% Stator Earth Fault Voltage 20Hz injection voltage				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
64S I Magnitude	01	CB		Not Settable
100% Stator Earth Fault Voltage 20Hz injection current				
64S R primary	01	CC		Not Settable
100% Stator Earth Fault Voltage 20Hz injection resistance				
64R CL Input	01	CD		Not Settable
Rotor Earth Fault CLIO measurement				
64R R Fault	01	CE		Not Settable
Rotor Earth Fault resistance				
DLR Ambient Temp	01	D0		Not Settable
Dynamic Line Rating Ambient Temperature				
Wind Velocity	01	D1		Not Settable
Wind Velocity				
Wind Direction	01	D2		Not Settable
Wind Direction				
Solar Radiation	01	D3		Not Settable
Solar Radiation				
DLR Ampacity	01	D4		Not Settable
Dynamic Line Rating Ampacity				
DLR CurrentRatio	01	D5		Not Settable
Dynamic Line Rating Current Ratio				
Dyn Conduct Temp	01	D6		Not Settable
Dynamic Conductor Temperature				
Xph Sen Watts	01	DD		Not Settable
Xph Sensitive Active Power				
IA-1 Peak	01	E4		Not Settable
CT1 Phase A Peak Through Fault Current Magnitude				
IB-1 Peak	01	E5		Not Settable
CT1 Phase B Peak Through Fault Current Magnitude				
IC-1 Peak	01	E6		Not Settable
CT1 Phase C Peak Through Fault Current Magnitude				
IA-1 2t	01	E7		Not Settable
CT1 Phase A Through Fault I2t				
IB-1 2t	01	E8		Not Settable
CT1 Phase B Through Fault I2t				
IC-1 2t	01	E9		Not Settable
CT1 Phase C Through Fault I2t				
IA-2 Peak	01	EA		Not Settable
CT2 Phase A Peak Through Fault Current Magnitude				
IB-2 Peak	01	EB		Not Settable
CT2 Phase B Peak Through Fault Current Magnitude				
IC-2 Peak	01	EC		Not Settable
CT2 Phase C Peak Through Fault Current Magnitude				
IA-2 2t	01	ED		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
CT2 Phase A Through Fault I2t				
IB-2 2t	01	EE		Not Settable
CT2 Phase B Through Fault I2t				
IC-2 2t	01	EF		Not Settable
CT2 Phase C Through Fault I2t				
Select Maint	01	F0	0	0 to 9, step 1
This selects the required maintenance record from that may be stored. A value of 0 corresponds to the latest record and so on.				
Maint Text	01	F1		Not Settable
Up to 16 Character description of the occurrence (refer to following sections).				
Maint Type	01	F2		Not Settable
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.				
Maint Data	01	F3		Not Settable
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.				
Evt Iface Source	01	FA		Not Settable
Interface on which the event was logged				
Evt Access Level	01	FB		Not Settable
Any security event that indicates that it came from an interface action, such as disabling a port, will also record the access level of the interface that initiated the event. This will be recorded in the 'Event State' field of the event.				
Evt Extra Info	01	FC		Not Settable
This cell provides supporting information for the event and can vary between the different event types.				
Evt Unique Id	01	FE		Not Settable
Each event will have a unique event id. The event id is a 32 bit unsigned integer that is incremented for each new event record and is stored in the record in battery-backed memory (BBRAM). The current event id must be non-volatile so as to preserve it du				
Reset Indication	01	FF	No	No or Yes
This serves to reset the trip LED indications provided that the relevant protection element has reset, to reset all LED and relays latched in the PSL, and to reset the latched alarms.				

Table 1 - Local viewing of 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”
“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 P24x or P44x the Event Value is an 8 or 16 bit word.* *For P34x or P64x it is an 8, 12, 16, 24 or 32-bit word.* *For P445 it is an 8, 12 or 16-bit word.* *For P44y, P54x, P547 or P841, it is an 8, 12, 16 or 24-bit word.* *For P74x it is a 12, 16, 24 or 32-bit word.* *For P746 or P849 it is a 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 Contacts
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 P24x the Event Value is is a 7 or 16-bit word.* *For P34x or P64x it is an 7, 11, 14, 15, 16, 22, 24 or 32-bit word.* *For P445 it is an 8, 12 or 16-bit word.* *For P44x it is a 7, 14 or 21 bit word.* *For P44y, P54x, P547 or P841, it is an 8, 12, 16, 24 or 32 bit word.* *For P74x it is a 12, 16, 24 or 32 bit word.* *For P746 or P849 it is a 24-bit word.*

2.1.3 Relay Alarm Conditions

Any alarm conditions generated by the relays are logged as individual events. This table shows examples of some of the alarm conditions and how they appear in the event list:

Bit position in 32-bit field	Alarm Status 1 (alarms 1 - 32)	Alarm Status 2 (alarms 33 - 64)	Alarm Status 3 (alarms 65 - 96)	User Alarms
0	Unused	CL Card I/P Fail	Battery Fail	SR User Alarm 1
1	F out of range	CL Card O/P Fail	Field Volt Fail	SR User Alarm 2
2	SG-opto DDB Invalid	CL Input 1 Alarm	Comm2 H/W FAIL	SR User Alarm 3
3	Prot'n Disabled	CL Input 2 Alarm	GOOSE IED Absent	SR User Alarm 4
4	VT Fail Alarm	CL Input 3 Alarm	NIC Not Fitted	SR User Alarm 5
5	CT-1 Fail Alarm	CL Input 4 Alarm	NIC No Response	SR User Alarm 6
6	CB Fail Alarm	CLI1 I< Fail Alm	NIC Fatal Error	SR User Alarm 7
7	I^ Maint Alarm	CLI2 I< Fail Alm	Unused	SR User Alarm 8

Bit position in 32-bit field	Alarm Status 1 (alarms 1 - 32)	Alarm Status 2 (alarms 33 - 64)	Alarm Status 3 (alarms 65 - 96)	User Alarms
8	I ^ Lockout Alarm	CLI3 I< Fail Alm	Unused	SR User Alarm 9
9	CB Ops Maint	CLI4 I< Fail Alm	Unused	SR User Alarm 10
10	CB Ops Lockout	64R R<1 Alarm	Unused	SR User Alarm 11
11	CB Op Time Maint	64R CL I/P Fail	NIC SW Mis-Match	SR User Alarm 12
12	CB Op Time Lock	CT Mismatch Alm	IP Addr Conflict	SR User Alarm 13
13	Fault Freq Lock	Loss of Life Alm	Unused	SR User Alarm 14
14	CB Status Alarm	FAA Alarm	Unused	SR User Alarm 15
15	Man CB Trip Fail	Thru Fault Alm	Unused	SR User Alarm 16
16	Man CB Close Fail	Circuit Flt Alm	Unused	MR User Alarm 17
17	Man CB Unhealthy	XThermPretrp Alm	Backup Setting	MR User Alarm 18
18	NPS Alarm	Diff CTS Alarm	Bad DNP Settings	MR User Alarm 19
19	Gen Thermal Alm	Man No Checksync	Unused	MR User Alarm 20
20	V/Hz Alarm	System Split Alm	Unused	MR User Alarm 21
21	Field Fail Alarm	Not Used	Invalid DNPoE IP	MR User Alarm 22
22	RTD Thermal Alm	Not Used	Invalid Config.	MR User Alarm 23
23	RTD Open Cct	Not Used	Test Mode Alm	MR User Alarm 24
24	RTD short Cct	Not Used	Contacts Blk Alm	MR User Alarm 25
25	RTD Data Error	Not Used	NIC HW Mismatch	MR User Alarm 26
26	RTD Board Fail	Not Used	NIC APP Mismatch	MR User Alarm 27
27	Freq Prot Alm	Not Used	Simul.GOOSE Alm	MR User Alarm 28
28	Voltage Prot Alm	Not Used	Unused	MR User Alarm 29
29	CT-2 Fail Alarm	Not Used	Unused	MR User Alarm 30
30	64S R<1 Alarm	Not Used	Unused	MR User Alarm 31
31	64S Fail Alarm	Not Used	Unused	MR User Alarm 32

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.

The User Alarms can be operated from an opto input or a control input using the PSL. They give an alarm LED and message on the LCD display and an alarm indication via the communications of an external condition, for example trip circuit supervision alarm, rotor earth fault alarm. The menu text editor in MiCOM S1 Studio can be used to edit the user alarm text to give a more meaningful description on the LCD display.

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. Normally this is assigned to relay 3, protection trip, but in the P746 it is assigned to Any Start or Any Trip. The fault measurements in the fault record are given at the time of the protection start.

The fault recorder does not stop recording until any start or relay 3 (protection trip) resets in order to record all the protection flags during the fault.

It is recommended that the triggering contact (relay 3 for example) 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 in the relay are logged as an event. For example:

Type of setting change	Displayed text in event record	Displayed value
Control/Support Setting	C & S Changed	22
Group # Change	Group # Changed	#
Where # = 1 to 4		

Note *Control/Support settings are communications, measurement, CT/VT ratio settings etc, which are not duplicated in the setting groups. When any of these settings are changed, the event record is created simultaneously. Changes to protection or disturbance recorder settings 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 S1 Studio 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 08 January 2015 18:45:28.633 GMT V<1 Trip A/AB ON

SE (Schneider Electric):	MiCOM P343
Model Number:	P343314B2M0360J
Address:	001 Column: 0F Row: 26
Event Type:	Setting event
Event Value:	00000001000000000000000000000000

Monday 08 January 2015 18:45:28.634 GMT Output Contacts

SE (Schneider Electric):	MiCOM P343
Model Number:	P343314B2M0360J
Address:	001 Column: 00 Row: 21
Event Type:	Device output changed state
Event Value:	00000000001100
OFF 0	R1 Trip CB
OFF 1	R2 Trip PrimeMov
ON 2	R3 Any Trip
ON 3	R4 General Alarm
OFF 4	R5 CB Fail
OFF 5	R6 E/F Trip
OFF 6	R7 Volt Trip
OFF 7	R8 Freq Trip
OFF 8	R9 Diff Trip
OFF 9	R10 SysBack Trip
OFF 10	R11 NPS Trip
OFF 11	R12 FFail Trip
OFF 12	R13 Power Trip
OFF 13	R14 V/Hz Trip

Monday 08 January 2015 18:45:28.633 GMT Voltage Prot Alm ON

SE (Schneider Electric):	MiCOM P343
Model Number:	P343314B2AM0360J
Address:	001 Column: 00 Row: 22
Event Type:	Alarm event
Event Value:	00001000000000000000000000000000
OFF 0	Freq out of range
OFF 1	System Split Alm
OFF 2	SG-opto Invalid

OFF 3	Prot'n Disabled
OFF 4	VT Fail Alarm
OFF 5	CTS-1 Fail Alarm
OFF 6	CB Fail
OFF 7	I^ Maint Alarm
OFF 8	I^ Lockout Alarm
OFF 9	CB OPs Maint
OFF 10	CB OPs Lockout
OFF 11	CB Op Time Maint
OFF 12	CB Op Time Lock
OFF 13	Fault Freq Lock
OFF 14	CB Status Alarm
OFF 15	CB Trip Fail
OFF 16	CB Close Fail
OFF 17	Man CB Unhealthy
OFF 18	NPS Alarm
OFF 19	Thermal Alarm
OFF 20	V/Hz Alarm
OFF 21	Field Fail Alarm
OFF 22	RTD Thermal Alm
OFF 23	RTD Open Cct
OFF 24	RTD short Cct
OFF 25	RTD Data Error
OFF 26	RTD Board Fail
OFF 27	Freq Prot Alm
ON 28	Voltage Prot Alm
OFF 29	CTS-2 Fail Alarm
OFF 30	64S R<1 Alarm
OFF 31	User Alarm 3
OFF 31	64S Fail Alarm

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 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.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
RECORD CONTROL	0B	00		
This column contains settings for Record Controls				
Alarm Event	0B	04	Enabled	Enabled, disabled
Disabling this setting means that no event is generated for alarms				
Relay O/P Event	0B	05	Enabled	Enabled, disabled
Disabling this setting means that no event will be generated for any change in logic output state.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Opto Input Event	0B	06	Enabled	Enabled, disabled
Disabling this setting means that no event will be generated for any change in logic input state.				
General Event	0B	07	Enabled	Enabled, disabled
Disabling this setting means that no General Events are generated				
Fault Rec Event	0B	08	Enabled	Enabled, disabled
Disabling this setting means that no event will be generated for any fault that produces a fault record				
Maint Rec Event	0B	09	Enabled	Enabled, disabled
Disabling this setting means that no event will be generated for any occurrence that produces a maintenance record.				
Protection Event	0B	0A	Enabled	Enabled, disabled
Disabling this setting means that any operation of protection elements will not be logged as an event				
Clear Dist Recs	0B	30	No	0 = No, 1 = Yes
Selecting "Yes" will cause the existing disturbance records to be cleared and an event will be generated indicating that the disturbance records have been erased.				
Security Event	0B	31	Enabled	Enabled, disabled
Disabling this setting means that any operation of security elements will not be logged as an event				
DDB 31 - 0	0B	40	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 63 - 32	0B	41	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 95 - 64	0B	42	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 127 - 96	0B	43	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 159 - 128	0B	44	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 191 - 160	0B	45	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 223 - 192	0B	46	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 255 - 224	0B	47	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 287 - 256	0B	48	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Chooses whether any individual DDB's 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 319 - 288	0B	49	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 351 - 320	0B	4A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 383 - 352	0B	4B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 415 - 384	0B	4C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 447 - 416	0B	4D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 479 - 448	0B	4E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 511 - 480	0B	4F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 543 - 512	0B	50	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 575 - 544	0B	51	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 607 - 576	0B	52	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 639 - 608	0B	53	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 671 - 640	0B	54	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DDB 703 - 672	0B	55	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 735 - 704	0B	56	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 767 - 736	0B	57	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 799 - 768	0B	58	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 831 - 800	0B	59	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 863 - 832	0B	5A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 895 - 864	0B	5B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 927 - 896	0B	5C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 959 - 928	0B	5D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 991 - 960	0B	5E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1023 - 992	0B	5F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1055 - 1024	0B	60	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1087 - 1056	0B	61	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Choose whether any individual DDB's 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 1119 - 1088	0B	62	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1151 - 1120	0B	63	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1183 - 1152	0B	64	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1215 - 1184	0B	65	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1247 - 1216	0B	66	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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	0B	67	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1311 - 1280	0B	68	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1343 - 1312	0B	69	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1375 - 1344	0B	6A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1407 - 1376	0B	6B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1439 - 1408	0B	6C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1471 - 1440	0B	6D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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.				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DDB 1503 - 1472	0B	6E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1535 - 1504	0B	6F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1567 - 1536	0B	70	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1599 - 1568	0B	71	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1631 - 1600	0B	72	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1663 - 1632	0B	73	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1695 - 1664	0B	74	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1727 - 1696	0B	75	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1759 - 1728	0B	76	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1791 - 1760	0B	77	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1823 - 1792	0B	78	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1855 - 1824	0B	79	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1887 - 1856	0B	7A	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Choose whether any individual DDB's 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 1919 - 1888	0B	7B	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1951 - 1920	0B	7C	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 1983 - 1952	0B	7D	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 2015 - 1984	0B	7E	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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 2047 - 2016	0B	7F	11111111111111111111111111111111(bin)	32-bit binary setting: 1 = event recording Enabled, 0 = event recording Disabled
Chooses whether any individual DDB's 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.				

Table 3 - Record control settings

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 (8 analogue channels and 32 digital channels). VDEW relays, however, have the same total record length but the VDEW protocol dictates that only 8 records can be extracted via the rear port.

The recorder stores actual samples that are taken at a rate of 24 samples per cycle.

Each disturbance record consists of a maximum of 9/12/13/15 analog data channels for P342/P343/P344/P345 and thirty-two digital data channels.

The "DISTURBANCE RECORDER" menu column is shown in Table 4.

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DISTURB RECORDER	0C	00		
This column contains settings for the Disturbance Recorder				
Duration	0C	52	1.5 s	0.1s to 10.5s step 0.01s
This sets the overall recording time.				
Trigger Position	0C	54	0.333	From 0% to 100% step 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 1.5 s with the trigger point being at 33.3% of this, giving 0.5 s pre-fault and 1s post fault recording times.				
Trigger Mode	0C	56	Single	Single, 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	0C	58	VAN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 2	0C	59	VBN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 3	0C	5A	VCN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 4	0C	5B	VN1	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 5	0C	5C	IA (IA-1)	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Selects any available analogue input to be assigned to this channel.				
Analog Channel 6	0C	5D	IB (IB-1)	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 7	0C	5E	IC (IC-1)	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 8	0C	5F	I Sensitive	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Analog Channel 9	0C	60	IN	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
AnalogChannel 10	0C	61	IA-2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
AnalogChannel 11	0C	62	IB-2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
AnalogChannel 12	0C	63	IC-2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
AnalogChannel 13	0C	64	VN2	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
AnalogChannel 14	0C	65	V64S	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
AnalogChannel 15	0C	66	I64S	VAN, VBN, VCN, VN1, IA, IB, IC, IN, I Sensitive, IA-2, IB-2, IC-2,VN2, V64S, I64S
Selects any available analogue input to be assigned to this channel.				
Digital Input 1	0C	80	Output R1	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 1 Trigger	0C	81	No Trigger	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 Input 2	0C	82	Output R2	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 2 Trigger	0C	83	No Trigger	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 Input 3	0C	84	Output R3	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 3 Trigger	0C	85	Trigger L/H	No trigger, Trigger L/H, trigger H/L

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 Input 4	0C	86	Output R4	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 4 Trigger	0C	87	No Trigger	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 Input 5	0C	88	Output R5	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 5 Trigger	0C	89	No Trigger	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 Input 6	0C	8A	Output R6	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 6 Trigger	0C	8B	No Trigger	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 Input 7	0C	8C	Output R7	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 7 Trigger	0C	8D	No Trigger	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 Input 8	0C	8E	Input L1 (P341 P342) Output R8 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 8 Trigger	0C	8F	No Trigger	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 Input 9	0C	90	Input L2 (P341 P342) Output R9 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 9 Trigger	0C	91	No Trigger	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 Input 10	0C	92	Input L3 (P341 P342) Output R10 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 10 Trigger	0C	93	No Trigger	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 Input 11	0C	94	Input L4 (P341 P342) Output R11 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 11 Trigger	0C	95	No Trigger	No trigger, Trigger L/H, trigger H/L

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 Input 12	0C	96	Input L5 (P341 P342) Output R12 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 12 Trigger	0C	97	No Trigger	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 Input 13	0C	98	Input L6 (P341 P342) Output R13 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 13 Trigger	0C	99	No Trigger	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 Input 14	0C	9A	Input L7 (P341 P342) Output R14 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 14 Trigger	0C	9B	No Trigger	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 Input 15	0C	9C	Input L8 (P341 P342) Input L1 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 15 Trigger	0C	9D	No Trigger	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 Input 16	0C	9E	Unused (P341 P342) Input L2 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 16 Trigger	0C	9F	No Trigger	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 Input 17	0C	A0	Unused (P341 P342) Input L3 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 17 Trigger	0C	A1	No Trigger	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 Input 18	0C	A2	Unused (P341 P342) Input L4 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 18 Trigger	0C	A3	No Trigger	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 Input 19	0C	A4	Unused (P341 P342) Input L5 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 19 Trigger	0C	A5	No Trigger	No trigger, Trigger L/H, trigger H/L

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 Input 20	0C	A6	Unused (P341 P342) Input L6 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 20 Trigger	0C	A7	No Trigger	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 Input 21	0C	A8	Unused (P341 P342) Input L7 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 21 Trigger	0C	A9	No Trigger	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 Input 22	0C	AA	Unused (P341 P342) Input L8 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 22 Trigger	0C	AB	No Trigger	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 Input 23	0C	AC	Unused (P341 P342) Input L9 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 23 Trigger	0C	AD	No Trigger	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 Input 24	0C	AE	Unused (P341 P342) Input L10 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 24 Trigger	0C	AF	No Trigger	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 Input 25	0C	B0	Unused (P341 P342) Input L11 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 25 Trigger	0C	B1	No Trigger	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 Input 26	0C	B2	Unused (P341 P342) Input L12 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 26 Trigger	0C	B3	No Trigger	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 Input 27	0C	B4	Unused (P341 P342) Input L13 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 27 Trigger	0C	B5	No Trigger	No trigger, Trigger L/H, trigger H/L

Courier Text	Col	Row	Default Setting	Available Setting
Description				
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 Input 28	0C	B6	Unused (P341 P342) Input L14 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 28 Trigger	0C	B7	No Trigger	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 Input 29	0C	B8	Unused (P341 P342) Input L15 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 29 Trigger	0C	B9	No Trigger	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 Input 30	0C	BA	Unused (P341 P342) Input L16 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 30 Trigger	0C	BB	No Trigger	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 Input 31	0C	BC	Unused (P341 P342) Function Key 10 (P343 P344 P345)	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 31 Trigger	0C	BD	No Trigger (P341 P342) Trigger L/H (P343 P344 P345)	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 Input 32	0C	BE	Unused	Any of 32 O/P Contacts or Any of 32 Opto Inputs or Internal Digital Signals
The digital channels may monitor any of the opto isolated inputs or output contacts, in addition to a number of internal IED digital signals, such as protection starts, LEDs etc.				
Input 32 Trigger	0C	BF	No Trigger	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.				

Table 4 - Disturbance recorder settings

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.

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	– + – +

Table 5 - Power modes

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.

For the energy measurements exporting Watts/VArs gives forward Whr/VArhr and importing Watts/VArs gives reverse Whr/VArhr.

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:

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASURE'T SETUP	0D	00		
This column contains settings for the measurement setup				
Default Display	0D	01	User Banner	Not Settable
This displays the default display which is possible to change whilst at the default level using the arrow keys. Only visible on UI.				
Local Values	0D	02	Primary	Primary, Secondary
Local Measurement Values.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	0D	03	Primary	Primary, Secondary
Remote Measurement Values.This setting controls whether measured values via the rear communication port are displayed as primary or secondary quantities.				
Measurement Ref	0D	04	VA	0 = VA, 1 = VB, 2 = VC, 3 = IA, 4 = IB, 5 = IC
Using this setting the phase reference for all angular measurements by the IED can be selected. This reference is for Measurements 1. Measurements 3 uses always IA local as a reference				
Measurement Mode	0D	05	0	0, 1, 2, 3
Measurement Mode				
Fix Dem Period	0D	06	15 mins	1 mins to 99 mins step 1 mins
Fixed Demand Interval				
Roll Sub Period	0D	07	1 mins	1 mins to 99 mins step 1 mins
Rolling demand sub period				
Num Sub Periods	0D	08	15	1 to 15 step 1
Number of rolling sub-periods				
Remote 2 Values	0D	0B	Primary	Primary, Secondary
The setting defines whether the values measured via the Second Rear Communication port are displayed in primary or secondary terms.				

Table 6 - Measurement setup settings

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.

4.8.1 Measurements 1

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASUREMENTS 1	02	00		
This column contains measurement parameters				
IA Magnitude IA-1 Magnitude	02	01		Not Settable
IA-1 Magnitude measurement				
IA Phase Angle IA-1 Phase Angle	02	02		Not Settable
IA-1 Phase Angle measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
IB Magnitude IB-1 Magnitude	02	03		Not Settable
IB-1 Magnitude measurement				
IB Phase Angle IB-1 Phase Angle	02	04		Not Settable
IB-1 Phase Angle measurement				
IC Magnitude IC-1 Magnitude	02	05		Not Settable
IC-1 Magnitude measurement				
IC Phase Angle IC-1 Phase Angle	02	06		Not Settable
IC-1 Phase Angle measurement				
IN Measured Mag	02	07		Not Settable
IN Measured Magnitude measurement				
IN Measured Ang	02	08		Not Settable
IN Measured Angle measurement				
IN Derived Mag IN-1 Derived Mag	02	09		Not Settable
IN Derived Magnitude measurement				
IN Derived Angle	02	0A		Not Settable
IN Derived Angle measurement				
Isen Magnitude	02	0B		Not Settable
Isen Magnitude measurement				
Isen Angle	02	0C		Not Settable
Isen Angle measurement				
I1 Magnitude	02	0D		Not Settable
I1-1 Magnitude measurement				
I2 Magnitude	02	0E		Not Settable
I2-1 Magnitude measurement				
I0 Magnitude	02	0F		Not Settable
I0-1 Magnitude measurement				
IA RMS	02	10		Not Settable
IA RMS measurement				
IB RMS	02	11		Not Settable
IB RMS measurement				
IC RMS	02	12		Not Settable
IC RMS measurement				
IN-2 Derived Mag	02	13		Not Settable
IN-2 Derived Magnitude measurement				
VAB Magnitude	02	14		Not Settable
VAB Magnitude measurement				
VAB Phase Angle	02	15		Not Settable
VAB Phase Angle measurement				
VBC Magnitude	02	16		Not Settable
VBC Magnitude measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
VBC Phase Angle	02	17		Not Settable
VBC Phase Angle measurement				
VCA Magnitude	02	18		Not Settable
VCA Magnitude measurement				
VCA Phase Angle	02	19		Not Settable
VCA Phase Angle measurement				
VAN Magnitude	02	1A		Not Settable
VAN Magnitude measurement				
VAN Phase Angle	02	1B		Not Settable
VAN Phase Angle measurement				
VBN Magnitude	02	1C		Not Settable
VBN Magnitude measurement				
VBN Phase Angle	02	1D		Not Settable
VBN Phase Angle measurement				
VCN Magnitude	02	1E		Not Settable
VCN Magnitude measurement				
VCN Phase Angle	02	1F		Not Settable
VCN Phase Angle measurement				
VN Measured Mag VN1 Measured Mag	02	20		Not Settable
VN Measured Mag measurement				
VN Measured Ang VN1 Measured Ang	02	21		Not Settable
VN Measured Angle measurement				
VN Derived Mag	02	22		Not Settable
VN Derived Mag measurement				
VN Derived Ang	02	23		Not Settable
VN Derived Angle measurement				
V1 Magnitude	02	24		Not Settable
V1 Magnitude measurement				
V2 Magnitude	02	25		Not Settable
V2 Magnitude measurement				
V0 Magnitude	02	26		Not Settable
V0 Magnitude measurement				
VAN RMS	02	27		Not Settable
VAN RMS measurement				
VBN RMS	02	28		Not Settable
VBN RMS measurement				
VCN RMS	02	29		Not Settable
VCN RMS measurement				
Frequency	02	2D		Not Settable
Frequency measurement				
I1 Magnitude	02	40		Not Settable
I1 Magnitude measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
I1 Phase Angle	02	41		Not Settable
I1 Phase Angle measurement				
I2 Magnitude	02	42		Not Settable
I2 Magnitude measurement				
I2 Phase Angle	02	43		Not Settable
I2 Phase Angle measurement				
I0 Magnitude	02	44		Not Settable
I0 Magnitude measurement				
I0 Phase Angle	02	45		Not Settable
I0 Phase Angle measurement				
V1 Magnitude	02	46		Not Settable
V1 Magnitude measurement				
V1 Phase Angle	02	47		Not Settable
V1 Phase Angle measurement				
V2 Magnitude	02	48		Not Settable
V2 Magnitude measurement				
V2 Phase Angle	02	49		Not Settable
V2 Phase Angle measurement				
V0 Magnitude	02	4A		Not Settable
V0 Magnitude measurement				
V0 Phase Angle	02	4B		Not Settable
V0 Phase Angle measurement				
VN2 Measured Mag	02	50		Not Settable
VN2 Measured Magnitude measurement				
VN2 Measured Ang	02	51		Not Settable
VN2 Measured Angle measurement				
C/S Voltage Mag	02	70		Not Settable
C/S Voltage Magnitude measurement				
C/S Voltage Ang	02	71		Not Settable
C/S Voltage Angle measurement				
CS Gen-Bus Mag	02	72		Not Settable
Visible if System Checks enabled, CS Gen-Bus Magnitude measurement				
CS Gen-Bus Ang	02	73		Not Settable
Visible if System Checks enabled, CS Gen-Bus Angle measurement				
Slip Frequency	02	74		Not Settable
Visible if System Checks enabled, Slip Frequency measurement				
CS Frequency	02	75		Not Settable
CS Frequency measurement				

Table 7 - Measurements 1

4.8.2 Measurements 2

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASUREMENTS 2	03	00		
This column contains measurement parameters				
A Phase Watts	03	01		Not Settable
A Phase Watts measurement				
B Phase Watts	03	02		Not Settable
B Phase Watts measurement				
C Phase Watts	03	03		Not Settable
C Phase Watts measurement				
A Phase VArs	03	04		Not Settable
A Phase VArs measurement				
B Phase VArs	03	05		Not Settable
B Phase VArs measurement				
C Phase VArs	03	06		Not Settable
C Phase VArs measurement				
A Phase VA	03	07		Not Settable
A Phase VA measurement				
B Phase VA	03	08		Not Settable
B Phase VA measurement				
C Phase VA	03	09		Not Settable
C Phase VA measurement				
3 Phase Watts	03	0A		Not Settable
3 Phase Watts measurement				
3 Phase VArs	03	0B		Not Settable
3 Phase VArs measurement				
3 Phase VA	03	0C		Not Settable
3 Phase VA measurement				
NPS Power S2	03	0D		Not Settable
NPS Power S2 measurement				
3Ph Power Factor	03	0E		Not Settable
3Ph Power Factor measurement				
APh Power Factor	03	0F		Not Settable
APh Power Factor measurement				
BPh Power Factor	03	10		Not Settable
BPh Power Factor measurement				
CPh Power Factor	03	11		Not Settable
CPh Power Factor measurement				
3Ph WHours Fwd	03	12		Not Settable
3Ph WHours Fwd measurement				
3Ph WHours Rev	03	13		Not Settable
3Ph WHours Rev measurement				
3Ph VArHours Fwd	03	14		Not Settable
3Ph VArHours Fwd measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
3Ph VArHours Rev	03	15		Not Settable
3Ph VArHours Rev measurement				
3Ph W Fix Demand	03	16		Not Settable
3Ph W Fix Demand measurement				
3Ph VArs Fix Dem	03	17		Not Settable
3Ph VArs Fix Dem measurement				
IA Fixed Demand	03	18		Not Settable
IA Fix Demand measurement				
IB Fixed Demand	03	19		Not Settable
IB Fix Demand measurement				
IC Fixed Demand	03	1A		Not Settable
IC Fix Demand measurement				
3 Ph W Roll Dem	03	1B		Not Settable
3 Ph W Roll Dem measurement				
3Ph VArs RollDem	03	1C		Not Settable
3Ph VArs RollDem measurement				
IA Roll Demand	03	1D		Not Settable
IA Roll Demand measurement				
IB Roll Demand	03	1E		Not Settable
IB Roll Demand measurement				
IC Roll Demand	03	1F		Not Settable
IC Roll Demand measurement				
3Ph W Peak Dem	03	20		Not Settable
3Ph W Peak Dem measurement				
3Ph VAr Peak Dem	03	21		Not Settable
3Ph VAr Peak Dem measurement				
IA Peak Demand	03	22		Not Settable
IA Peak Demand measurement				
IB Peak Demand	03	23		Not Settable
IB Peak Demand measurement				
IC Peak Demand	03	24		Not Settable
IC Peak Demand measurement				
Reset Demand	03	25	No	No or Yes
Reset Demand				
NPS Power S2 CT2	03	26		Not Settable
NPS Power S2 CT2 measurement				

Table 8 - Measurements 2

4.8.3 Measurements 3

Courier Text	Col	Row	Default Setting	Available Setting
Description				
MEASUREMENTS 3	04	00		

Courier Text	Col	Row	Default Setting	Available Setting
Description				
This column contains measurement parameters				
IA-2 Magnitude	04	01		Not Settable
IA-2 Magnitude measurement				
IA-2 Phase Angle	04	02		Not Settable
IA-2 Phase Angle measurement				
IB-2 Magnitude	04	03		Not Settable
IB-2 Magnitude measurement				
IB-2 Phase Angle	04	04		Not Settable
IB-2 Phase Angle measurement				
IC-2 Magnitude	04	05		Not Settable
IC-2 Magnitude measurement				
IC-2 Phase Angle	04	06		Not Settable
IC-2 Phase Angle measurement				
IA Differential	04	07		Not Settable
IA Differential measurement				
IB Differential	04	08		Not Settable
IB Differential measurement				
IC Differential	04	09		Not Settable
IC Differential measurement				
IA Bias	04	0A		Not Settable
IA Bias measurement				
IB Bias	04	0B		Not Settable
IB Bias measurement				
IC Bias	04	0C		Not Settable
IC Bias measurement				
IREF Diff	04	0D		Not Settable
IREF Diff measurement				
IREF Bias	04	0E		Not Settable
IREF Bias measurement				
VN 3rd Harmonic	04	0F		Not Settable
VN 3rd Harmonic measurement				
NPS Thermal	04	10		Not Settable
NPS Thermal measurement				
Reset NPSThermal	04	11	No	No or Yes
Reset NPSThermal command.				
RTD 1	04	12		Not Settable
RTD 1 measurement				
RTD 2	04	13		Not Settable
RTD 2 measurement				
RTD 3	04	14		Not Settable
RTD 3 measurement				
RTD 4	04	15		Not Settable
RTD 4 measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
RTD 5	04	16		Not Settable
RTD 5 measurement				
RTD 6	04	17		Not Settable
RTD 6 measurement				
RTD 7	04	18		Not Settable
RTD 7 measurement				
RTD 8	04	19		Not Settable
RTD 8 measurement				
RTD 9	04	1A		Not Settable
RTD 9 measurement				
RTD 10	04	1B		Not Settable
RTD 10 measurement				
RTD Open Cct	04	1C		Not Settable
Displays the status of the ten RTDs as a binary string. 0 = No Open Circuit, 1 = Open Circuit. The Open Cct alarms are latched.				
RTD Short Cct	04	1D		Not Settable
Displays the status of the ten RTDs as a binary string. 0 = No Short Circuit, 1 = Short Circuit. The Short Cct alarms are latched.				
RTD Data Error	04	1E		Not Settable
Displays the status of the ten RTDs as a binary string. 0 = No Data Error, 1 = Data Error. The Data Error alarms are latched.				
Reset RTD Flags	04	1F	No	No or Yes
Reset RTD alarms command. Resets latched RTD Open Cct, Short Cct, Data Error alarms.				
APh Sen Watts	04	20		Not Settable
APh Sensitive Watts measurement				
APh Sen VArs	04	21		Not Settable
APh Sensitive VArs measurement				
APh Power Angle	04	22		Not Settable
APh Sensitive Power Angle measurement				
Thermal Overload	04	23		Not Settable
Thermal Overload measurement				
Reset ThermalO/L	04	24	No	No or Yes
Reset Thermal Overload command. Resets thermal state to 0.				
CLIO Input 1	04	25		Not Settable
CLIO Input 1 measurement				
CLIO Input 2	04	26		Not Settable
CLIO Input 2 measurement				
CLIO Input 3	04	27		Not Settable
CLIO Input 3 measurement				
CLIO Input 4	04	28		Not Settable
CLIO Input 4 measurement				
F Band1 Time (s)	04	30		Not Settable
Turbine Abnormal Frequency (TAF). Band 1 Accumulated Time				
Reset Freq Band1	04	32	No	No or Yes
Reset TAF Band 1 Time				
F Band2 Time (s)	04	34		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Turbine Abnormal Frequency (TAF). Band 2 Accumulated Time				
Reset Freq Band2	04	36	No	No or Yes
Reset TAF Band 2 Time				
F Band3 Time (s)	04	38		Not Settable
Turbine Abnormal Frequency (TAF). Band 3 Accumulated Time				
Reset Freq Band3	04	3A	No	No or Yes
Reset TAF Band 3 Time				
F Band4 Time (s)	04	3C		Not Settable
Turbine Abnormal Frequency (TAF). Band 4 Accumulated Time				
Reset Freq Band4	04	3E	No	No or Yes
Reset TAF Band 4 Time				
F Band5 Time (s)	04	40		Not Settable
Turbine Abnormal Frequency (TAF). Band 5 Accumulated Time				
Reset Freq Band5	04	42	No	No or Yes
Reset TAF Band 5 Time				
F Band6 Time (s)	04	44		Not Settable
Turbine Abnormal Frequency (TAF). Band 6 Accumulated Time				
Reset Freq Band6	04	46	No	No or Yes
Reset TAF Band 6 Time				
df/dt	04	48		Not Settable
dep on df/dt setting in configuration collumn				
Volts/Hz	04	50		Not Settable
Vab/Frequency				
64S V Magnitude	04	52		Not Settable
Low frequency injection St EF Voltage magnitude measured at the relay terminal				
64S I Magnitude	04	54		Not Settable
Low frequency injection St EF Current magnitude measured at the relay terminal				
64S I Angle	04	55		Not Settable
St EF current angle measurement, affected by Comp Angle setting when St EF is enabled. I64S phase angle relative to V64S vector.				
64S R secondary	04	57		Not Settable
St EF secondary resistance measurement at the relay terminal, affected by Series R and Parallel G settings				
64S R primary	04	58		Not Settable
St EF primary resistance, converted from secondary resistance using the R Factor setting				
64R CL Input	04	71		Not Settable
64S R primary measurement				
64R R Fault	04	72		Not Settable
64R R Fault measurement				
IA Diff PU	04	91		Not Settable
IA Diff PU measurement				
IB Diff PU	04	92		Not Settable
IB Diff PU measurement				
IC Diff PU	04	93		Not Settable
IC Diff PU measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
IA Bias PU	04	94		Not Settable
IA Bias PU measurement				
IB Bias PU	04	95		Not Settable
IB Bias PU measurement				
IC Bias PU	04	96		Not Settable
IC Bias PU measurement				
IA Diff 2H	04	97		Not Settable
IA Diff 2H measurement				
IB Diff 2H	04	98		Not Settable
IB Diff 2H measurement				
IC Diff 2H	04	99		Not Settable
IC Diff 2H measurement				
IA Diff 5H	04	9A		Not Settable
IA Diff 5H measurement				
IB Diff 5H	04	9B		Not Settable
IB Diff 5H measurement				
IC Diff 5H	04	9C		Not Settable
IC Diff 5H measurement				
CT2 I1 Mag	04	9D		Not Settable
CT2 I1 Magnitude measurement				
CT2 I1 Ang	04	9E		Not Settable
CT2 I1 Phase Angle measurement				
CT2 I2 Mag	04	9F		Not Settable
CT2 I2 Magnitude measurement				
CT2 I2 Ang	04	A0		Not Settable
CT2 I2 Phase Angle measurement				
CT2 I0 Mag	04	A1		Not Settable
CT2 I0 Magnitude measurement				
CT2 I0 Ang	04	A2		Not Settable
CT2 I0 Phase Angle measurement				
CT1 I2/I1	04	A3		Not Settable
CT1 I2/I1 measurement				
CT2 I2/I1	04	A4		Not Settable
CT2 I2/I1 measurement				

Table 9 - Measurements 3

4.8.4 Measurements 4

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Hot Spot T	05	01		Not Settable
Hot Spot T measurement				
Top Oil T	05	02		Not Settable

Courier Text	Col	Row	Default Setting	Available Setting
Description				
Top Oil T measurement				
Reset Xthermal	05	03	No	No or Yes
Reset Thermal Overload command. Resets thermal state to 0.				
Ambient T	05	04		Not Settable
Ambient T measurement				
TOL Pretrip left	05	05		Not Settable
Thermal OverLoad pre-trip time left. TOL Pretrip left measurement				
LOL status	05	06		Not Settable
Accumulated Loss Of Life. Invisible only when the turbine abnormal frequency protection is not enabled.				
Reset LOL	05	07	No	No or Yes
Reset Loss Of Life (LOL) command. Resets state to 0.				
Rate of LOL	05	08		Not Settable
Rate of LOL (ROLOL) measurement				
LOL Ageing Fact	05	09		Not Settable
Aging Acceleration Factor (FAA). LOL Aging Factor measurement				
Lres at Design T	05	0A		Not Settable
Residual life hours at design temperature QH,r. Lres at designed measurement				
FAA,m	05	0B		Not Settable
Mean Aging Acceleration Factor (FAA,m). FAA,m measurement				
Lres at FAA,m	05	0C		Not Settable
Residual life hours at FAA,m (LRES(FAA,m)). Lres at FAA,m measurement				
Max Iac	05	20		Not Settable
Max Iac measurement				
DLR Ambient Temp	05	22		Not Settable
DLR Ambient Temp measurement				
Wind Velocity	05	24		Not Settable
Wind Velocity measurement				
Wind Direction	05	26		Not Settable
Wind Direction measurement				
Solar Radiation	05	28		Not Settable
Solar Radiation measurement				
Effct wind angle	05	32		Not Settable
Effct wind angle measurement				
Pc	05	34		Not Settable
Pc measurement				
Pc, natural	05	36		Not Settable
Pc, natural measurement				
Pc1, forced	05	38		Not Settable
Pc1, forced measurement				
Pc2, forced	05	3A		Not Settable
Pc2, forced measurement				
DLR Ampacity	05	3C		Not Settable
DLR Ampacity measurement				

Courier Text	Col	Row	Default Setting	Available Setting
Description				
DLR CurrentRatio	05	3E		Not Settable
DLR CurrentRatio measurement				
Dyn Conduct Temp	05	40		Not Settable
Dyn Conduct Temp measurement				
Steady Conduct T	05	42		Not Settable
Steady Conduct T measurement				
Time Constant	05	44		Not Settable
Time Constant measurement				

Table 10 - Measurements 4

Notes:

PRODUCT DESIGN

CHAPTER 10

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

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FIGURES

TABLES

1 RELAY SYSTEM OVERVIEW

1.1 Hardware Overview

The relay is based on a modular hardware design where each module performs a separate function. This section describes the functional operation of the various hardware modules. Some modules are essential while others are optional depending on the user's requirements (see *Product Specific Options* and *Hardware Communications Options*).

All modules are connected by a parallel data and address bus which 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 transferring sample data from the input module to the processor. See the *Relay modules* diagram.

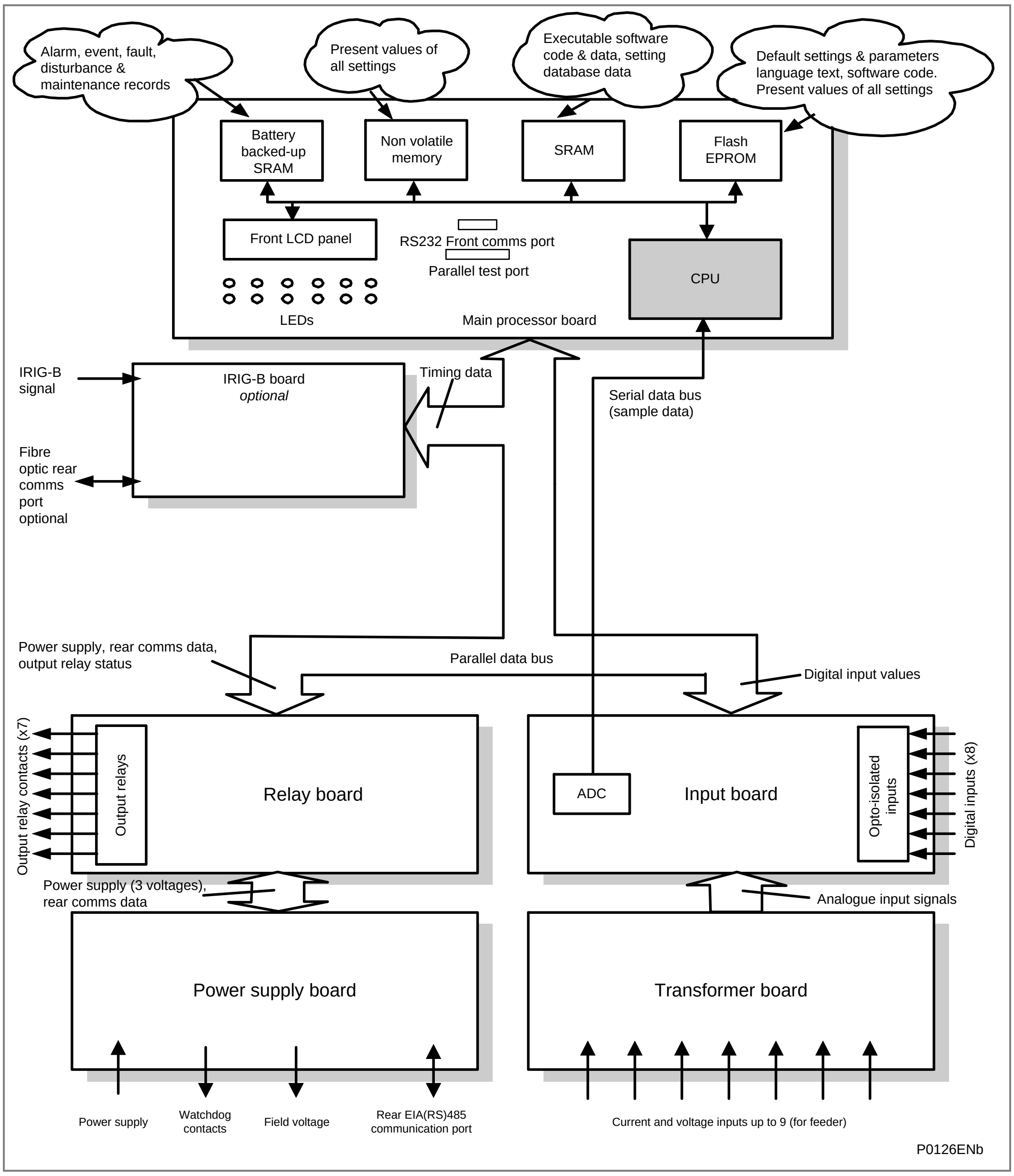


Figure 1 - Relay modules and information flow

1.2 Mechanical Layout

The relay case is pre-finished steel with a conductive covering of aluminum and zinc. This provides good earthing at all joints with a low impedance path to earth that is essential for shielding from external noise. The boards and modules use multi-point grounding (earthing) to improve 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, output relay contacts, power supply and 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 boards 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 have internal shorting links inside the relay. These 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 or 22 LEDs (depending on the model) mounted on an aluminum backing plate.

1.3 Processor Board

The processor board performs all calculations for the relay and controls the operation of all other modules in the relay. The processor board also contains and controls the user interfaces (LCD, LEDs, keypad and communication interfaces).

The relay is based around a TMS320VC33-150MHz (peak speed), floating-point, 32-bit Digital Signal Processor (DSP) operating at a clock frequency of half this speed. 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 directly behind the relay's front panel. This allows the LCD and LEDs and front panel communication ports to be mounted on the processor board. These ports are:

- The 9-pin D-connector for EIA(RS)232 serial communications used for MiCOM S1 Studio and Courier communications.
- The 25-pin D-connector relay test port for parallel communication.

All serial communication is handled using a Field Programmable Gate Array (FPGA).

The main processor board has:

- 2 MB SRAM for the working area. This is fast access (zero wait state) volatile memory used to temporarily store and execute the processor software.
- 4 MB flash ROM to store the software code, text, configuration data, default settings, and present settings.
- 4 MB battery-backed SRAM to store disturbance, event, fault and maintenance records.

Note	*With hardware revisions L and M, the SRAM size has changed from 2MB to 8MB; and the Flash size has changed from 4MB to 8MB.*

1.4 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 in 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 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.

1.5 Input Module

The input module provides the interface between the relay processor board(s) and the analog and digital signals coming into the relay. The input module varies depending on the MiCOM model number. The variations include:

Model	Input Boards	Transformer Boards	Voltage Inputs	Current Inputs	Notes
P342	1	1	4	5	
P343	1	2	4/5/6	8/9	
P344	1	2	4/5/6	8/9	P344 input module is the same as the P343 except it includes an additional voltage input, so providing five voltage inputs and eight current inputs
P345	1	2	4/5/6	8/9	P345 input module is the same as the P344 except it includes an additional 20 Hz current and 20 Hz voltage input for 100% stator earth fault protection.

1.5.1 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.

1.5.2 Input Board

The main input board is shown as a block diagram in the *Main input board* diagram. It provides the circuitry for the digital input signals and the Analog-to-Digital (A-D) conversion for the analog signals. 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 main processor board through the serial data bus. On the input board, the analog signals are converted using a dedicated sigma-delta A-D convertor for each channel. This allows all of the channels to be sampled concurrently with no sampling skew between channels. The sampled signals are then digitally filtered prior to the data being sent to the main processor via the serial link. In relay models using the second transformer board, a second input board is also fitted to provide the A-D conversion for the additional channels

The signal multiplexing arrangement provides for 16 analog channels to be sampled. This allows for up to 9 current inputs and 4 voltage inputs to be accommodated. The 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 kept at 24 samples per cycle of the power waveform by a logic control circuit driven by the frequency tracking function on the main processor board. The calibration non-volatile memory holds the calibration coefficients that are used by the processor board to correct for any amplitude or phase error introduced by the transformers and analog circuitry.

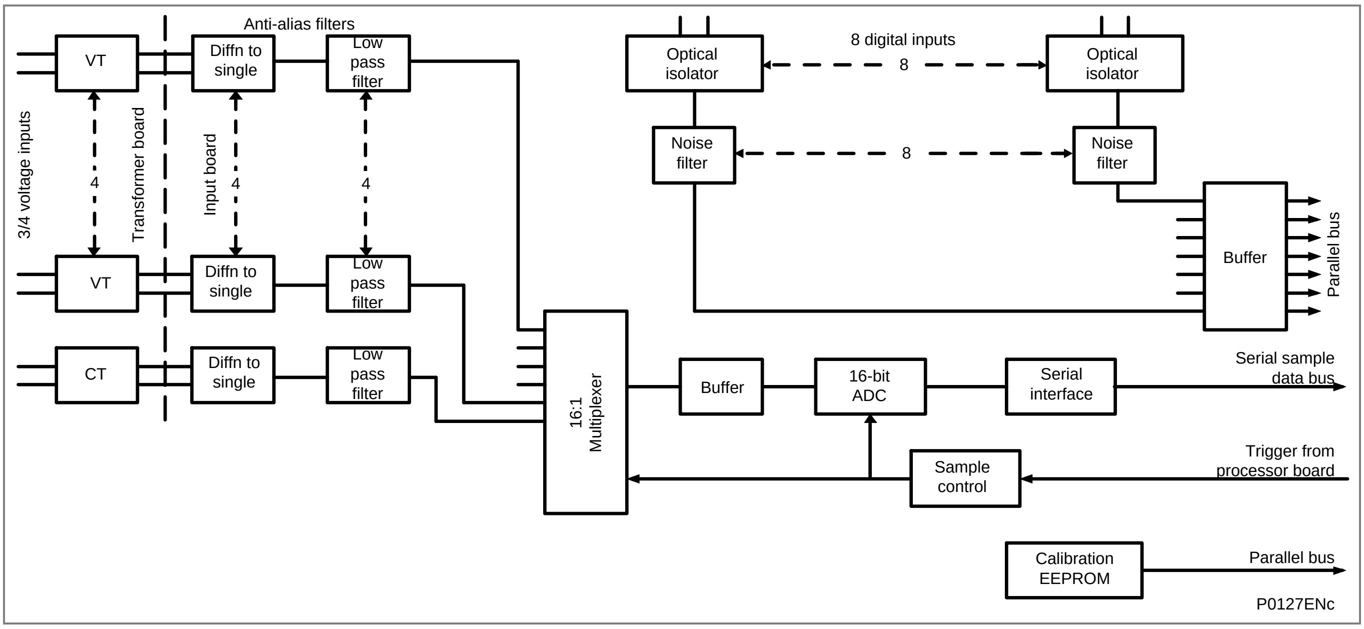


Figure 2 - Main input board

The other function of the input board is to read the signals on the digital inputs and send them through the parallel data bus to the processor board. The input board holds eight optical isolators for connecting up to eight digital input signals. Opto-isolators are used with digital signals for the same reason as transformers are used with analog signals: to isolate the relay's electronics from the power system environment. A 48 V 'field voltage' supply at the back of the relay is used to drive the digital opto-inputs. The input board has hardware filters to remove noise from the digital signals. The digital signals are then buffered so they can be read on the parallel data bus. Depending on the relay model, more than eight digital input signals can be accepted by the relay. This is done using an additional opto-board that contains the same provision for eight isolated digital inputs as the main input board, but does not contain any of the circuits for analog signals which are provided on the main input board.

1.5.3 Universal Opto Isolated Logic Inputs

This series of relays have universal opto-isolated logic inputs that can be programmed for the nominal battery voltage of the circuit of which they are a part. This allows different voltages for different circuits such as signaling and tripping. They can also be programmed as Standard 60% - 80% or 50% - 70% to satisfy different operating constraints.

Threshold levels are shown in this table:

Nominal battery voltage (Vdc)	Standard 60% - 80%		50% - 70%	
	No operation (Logic 0) Vdc	Operation (Logic 1) Vdc	No operation (Logic 0) Vdc	Operation (Logic 1) Vdc
24/27	<16.2	>19.2	<12.0	>16.8
30/34	<20.4	>24.0	<15.0	>21.0
48/54	<32.4	>38.4	<24.0	>33.6
110/125	<75.0	>88.0	<55.0	>77.0
220/250	<150.0	>176.0	<110	>154

Table 1 - Threshold levels

This lower value eliminates fleeting pick-ups 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 selectable filtering. This allows a pre-set ½ cycle filter to be used to prevent induced noise on the wiring. However, although the ½ cycle filter is secure it can be slow, particularly for intertripping. If the ½ cycle filter is switched off to improve speed, double pole switching or screened twisted cable may be needed on the input to reduce ac noise.

1.6 Power Supply Module (including Output Relays)

The power supply module contains two boards, one for the power supply unit and the other for the output relays. It provides power to all of the other modules in the relay, as well as the EIA(RS)485 electrical connection for the rear communication port. The second board of the power supply module contains the relays that provide the output contacts.

1.6.1 Power Supply Board (including EIA(RS)485 Communication Interface)

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).

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 options are shown in the following table:

Nominal dc range	Nominal ac range
24 - 32 V dc	dc only
48 - 110 V dc	dc only
110 - 250 V dc	100 - 240 V ac rms

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 in the relay. Three voltage levels are used in the relay: 5.1 V for all of the digital circuits, ±16 V for the analog electronics such as on the input board, and 22 V for driving the output relay coils. All power supply voltages including the 0 V earth line are distributed around the relay through the 64-way ribbon cable. The power supply board also provides the 48 V field voltage. 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 that is transmitted and received. All internal communication of data from the power supply board is through the output relay board connected to the parallel bus.

The watchdog facility has two output relay contacts, one Normally Open (N/O)and one Normally Closed (N/C). These are driven by the main processor board and indicate 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 10 A.

1.6.2 Output Relay Board

There are two versions of the output relay board:

- one with seven relays, three normally open contacts and four changeover contacts and
- one with eight relays, six normally open contacts and two changeover contacts.

For relay models with suffix A hardware, only the seven output relay boards were available. For equivalent relay models in suffix B hardware or greater the base numbers of output contacts, using the seven output relay boards, is being maintained for compatibility. The eight output relay board is only used for new relay models or existing relay models available in new case sizes or to provide additional output contacts to existing models for suffix issue B or greater hardware.

1.6.3 High Break Relay Board

One ‘high break’ output relay board consisting of four normally open output contacts is available for the P342 and one or two boards is available for the P343/P344/P345 as an option.

This board uses 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 because 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 <0.2 ms and is switched off after 7.5 ms. When the control input resets to open the contacts, the SSD is again turned on for 7.5 ms. The miniature relay resets in nominally 3.5 ms before the SSD 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 (<0.2 ms) these high break output contacts have the added advantage of being very fast operating. See the *High break contact operation* diagram below:

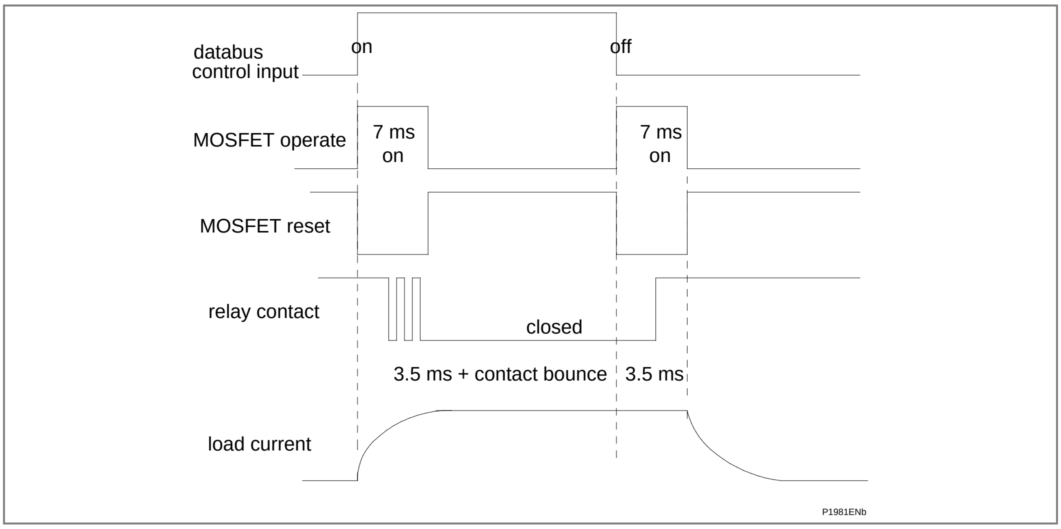


Figure 3 - High break contact operation

1.6.3.1 High Break Contact Applications

1. Efficient Scheme Engineering

   In traditional hardwired scheme designs, high break capability could only be achieved using external electromechanical trip relays. External tripping relays can be used or the high break contacts inside MiCOM relays can be used, reducing panel space.

2. Accessibility of CB Auxiliary Contacts

   Common practice is to use circuit breaker 52a (CB Closed) auxiliary contacts to break the trip coil current on breaker opening, easing the duty on the protection contacts. In cases such as operation of disconnectors, or retrofitting, 52a contacts may be unavailable or unreliable. High break contacts can be used to break the trip coil current in these applications.

3. Breaker Fail

   The technique to use 52a contacts in trip circuits was described above. However, in the event of failure of the local circuit breaker (stuck breaker), or defective auxiliary contacts (stuck contacts), the 52a contact action is incorrect. The interrupting duty at the local breaker then falls on the relay output contacts which may not be rated to perform this duty. MiCOM high break contacts will avoid the risk of burnt relay contacts.

4. Initiation of Teleprotection

   The MiCOM high break contacts also offer fast making, which can provide faster tripping. Also fast keying of teleprotection is a benefit. Fast keying bypasses the usual contact operation time so that permissive, blocking and intertrip commands can be routed faster.

1.7 Product Specific Options

Product Specific Options may mean that an additional board may be present if it was specified when the relay was ordered. The product specific options commonly allow a choice of RTD, CLIO, different numbers of Optos, Relays (including High Break relays). These options are shown in the *Ordering Options* section in *Chapter 1 – Introduction*.

1.8 Current Loop Input Output (CLIO) Board

The Current Loop Input Output (CLIO) board is an order option. The CLIO board is powered from the 22 V power rail that is used to drive the output relays.

Four analog (or current loop) inputs are provided for transducers with ranges of 0 to 1 mA, 0 to 10 mA, 0 to 20 mA or 4 to 20 mA. The input current data is read by the processor through the parallel data bus, and is used to provide measurements from various transducers such as vibration monitors, tachometers and pressure transducers.

For each of the four current loop inputs there are two separate input circuits, 0 to 1 mA and 0 to 20 mA. The latter is also used for 0 to 10 mA and 4 to 20 mA transducer inputs. The anti-alias filters have a nominal cut-off frequency (3 dB point) of 23 Hz to reduce power system interference from the incoming signals. Four analog current outputs are provided with ranges of 0 to 1 mA, 0 to 10 mA, 0 to 20 mA or 4 to 20 mA which can alleviate the need for separate transducers. These may be used to feed standard moving coil ammeters for analog indication of certain measured quantities or into a SCADA using an existing analog RTU.

Each of the four current loop outputs provides one 0 to 1 mA output, one 0 to 20 mA output and one common return. Suitable software scaling of the value written to the board allows the 0 to 20 mA output to also provide 0 to 10 mA and 4 to 20 mA. Screened leads are recommended for use on the current loop output circuits.

The refresh interval for the outputs is nominally 50 ms. Any measurements that do not fit this timing are updated once every second.

All external connections to the current loop I/O board are made using the same 15-way light duty I/O connector SL3.5/15/90F used on the RTD board. Two such connectors are used, one for the current loop outputs and one for the current loop inputs.

The I/O connectors accommodate wire sizes in the range 1/0.85 mm (0.57 mm^2) to 1/1.38 mm (1.5 mm^2) and their multiple conductor equivalents. The use of screened cable is recommended. The screen terminations should be connected to the case earth of the relay.

Basic Insulation (300 V) is provided between analog inputs or outputs and earth, and between analog inputs and outputs. However, there is no insulation between one input and another or one output and another.

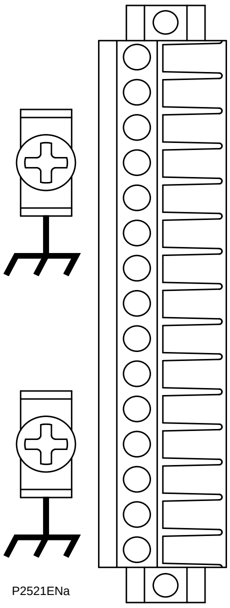
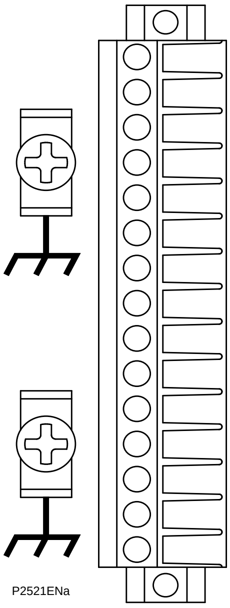
Connection	IO Blocks	Connection
Outputs		
Screen channel 1		0 - 10/0 - 20/4 - 20 mA channel 1 0 - 1 mA channel 1 Common return channel 1
Screen channel 2		0 - 10/0 - 20/4 - 20 mA channel 2 0 - 1 mA channel 2 Common return channel 2
Screen channel 3		0 - 10/0 - 20/4 - 20 mA channel 3 0 - 1 mA channel 3 Common return channel 3
Screen channel 4		0 - 10/0 - 20/4 - 20 mA channel 4 0 - 1 mA channel 4 Common return channel 4
Inputs		
Screen channel 1		0 - 10/0 - 20/4 - 20 mA channel 1 0 - 1 mA channel 1 Common channel 1
Screen channel 2		0 - 10/0 - 20/4 - 20 mA channel 2 0 - 1 mA channel 2 Common channel 2
Screen channel 3		0 - 10/0 - 20/4 - 20 mA channel 3 0 - 1 mA channel 3 Common channel 3
Screen channel 4		0 - 10/0 - 20/4 - 20 mA channel 4 0 - 1 mA channel 4 Common channel 4

Figure 4 - Current loop input output board

1.9 IRIG-B Board (Optional)

The optional IRIG-B board is an order option that can be fitted to provide an accurate timing reference for the relay. This can be used wherever an IRIG-B signal is available. The IRIG-B signal is connected to the board with 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 1 ms. 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 or Ethernet rear communication port.

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).

1.10 Resistance Temperature Detector (RTD) Board (Optional)

The optional Resistance Temperature Detectors (RTD) board is used to monitor the winding and ambient temperature readings from up to ten PT100 RTD that are each connected using a 3-wire connection. The board is powered from the 22 V power rail that is used to drive the output relays. The RTD board includes two redundant channels that are connected to high stability resistors to provide reference readings. These are used to check the operation of the RTD board. The temperature data is read by the processor through the parallel data bus, and is used to provide thermal protection of the windings.

1.11 Second Rear Communications Board (Optional)

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 runs 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.

This optional second rear port is designed typically for dial-up modem access by protection engineers and operators, when the main port is reserved for SCADA traffic.

The port supports full local or remote protection and control access by MiCOM S1 Studio software. The second rear port is also available with an on board IRIG-B input.

The second rear communications board, Ethernet and IRIG-B boards are mutually exclusive since they use the same hardware slot. For this reason two versions of second rear communications and Ethernet boards are available; one with an IRIG-B input and one without. The second rear communications board is shown in the following diagram.

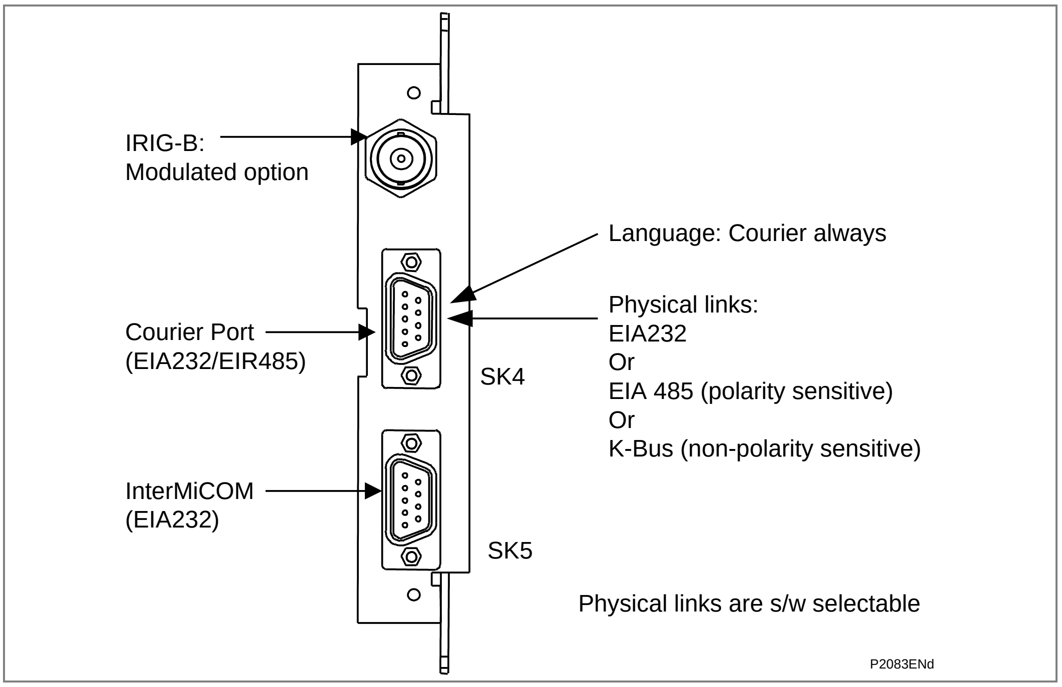


Figure 5 - Rear communications port

1.12 Ethernet Board (Options)

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 and/or un-modulated). This board, the IRIG-B board mentioned in the Hardware Communications Options section and second rear comms. board mentioned in the IRIG-B Board section are mutually exclusive as they all use 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. The relay modules and information flow diagram shows the modules of the relay and the flow of information between them.

This optional board is required for providing network connectivity using IEC 61850. There are a variety of different boards which provide Ethernet connectivity.

Important	**The choice of communication board options varies according to the Hardware Suffix and the Software Version of the MiCOM product. These are shown in the *Ordering Options* section in *Chapter 1 – Introduction*.**

By way of example, the board options may include:

- single-port Ethernet boards (which use 10/100 Mbits/s Copper and modulated/unmodulated IRIG-B connectivity)
- single-port Ethernet boards (which use 100MBits/s optical fibre connectivity)
- Redundant Ethernet Self-Healing Ring with one or more multi-mode fibre optic ports and modulated/unmodulated IRIG-B connectivity
- Redundant Ethernet RSTP with one or more multi-mode fibre optic ports and modulated/unmodulated IRIG-B connectivity
- Redundant Ethernet Dual Homing Star with one or more multi-mode fibre optic ports and modulated/unmodulated IRIG-B connectivity
- Redundant Ethernet Parallel Redundancy Protocol (PRP) with one or more multi-mode fibre optic ports and modulated/unmodulated IRIG-B connectivity
- Redundant Ethernet with PRP/HSR/Dual IP and a mixture of LC/RJ45 ports and modulated/unmodulated IRIG-B connectivity

These options are mutually exclusive as they all use slot A in the relay case.

Note	*Each Ethernet board has a unique MAC address used for each Ethernet communication interface. The MAC address is printed on the rear of the board, next to the Ethernet sockets.*

Note	*The 100 Mbits/s Fiber Optic ports use ST/LC type connectors and are suitable for 1310 nm 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 m and confined to one bay or cubicle.

When using IEC 61850 communications through the Ethernet board, the rear EIA(RS)485 and front EIA(RS)232 ports are also available for simultaneous use, both using the Courier protocol.

One example of an Ethernet board is shown in this *Ethernet board connectors* diagram:

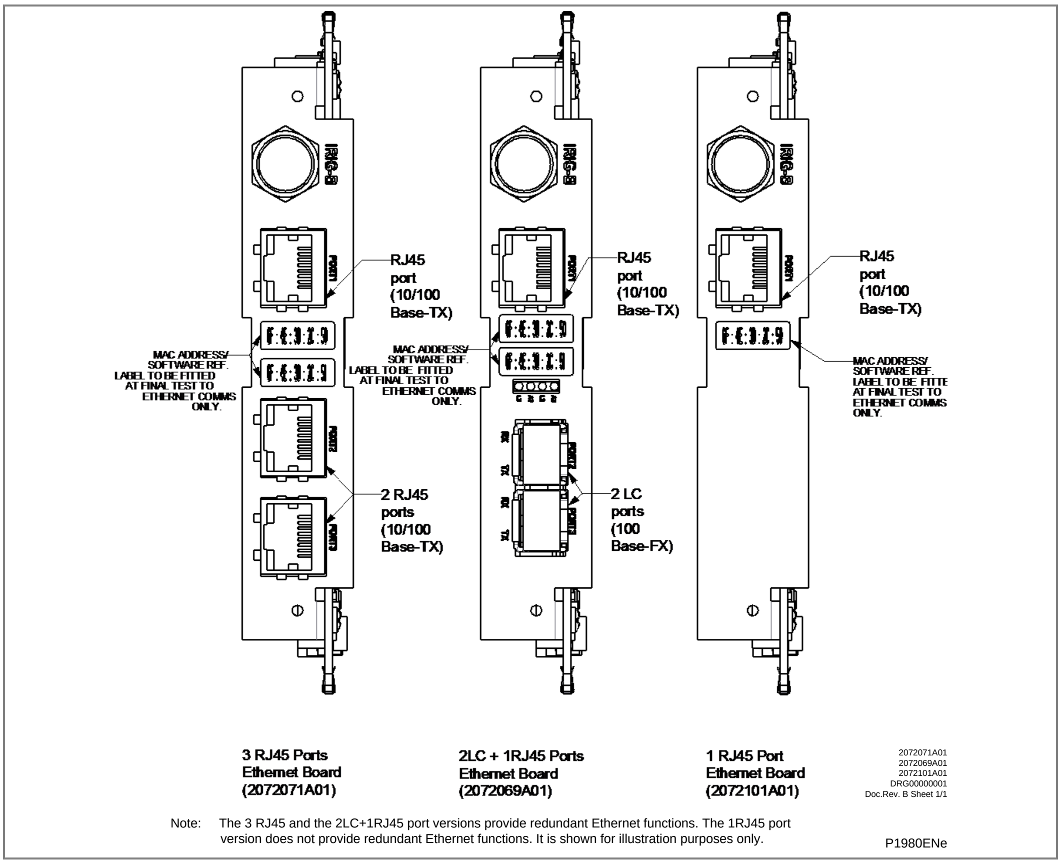


Figure 6 - Ethernet board connectors (3 RJ45 or 2 LC + RJ45 or 1 RJ45)

2 RELAY SOFTWARE

The relay software was introduced in the overview of the relay at the start of this chapter. The software can be considered to be made up of these sections:

- The real-time operating system
- The system services software
- The platform software
- The protection and control software

These four elements are all processed by the same processor board.This section describes in detail the ***platform software*** and the ***protection and control software***, which between them control the functional behavior of the relay. The following *Relay software structure* diagram shows the structure of the relay software.

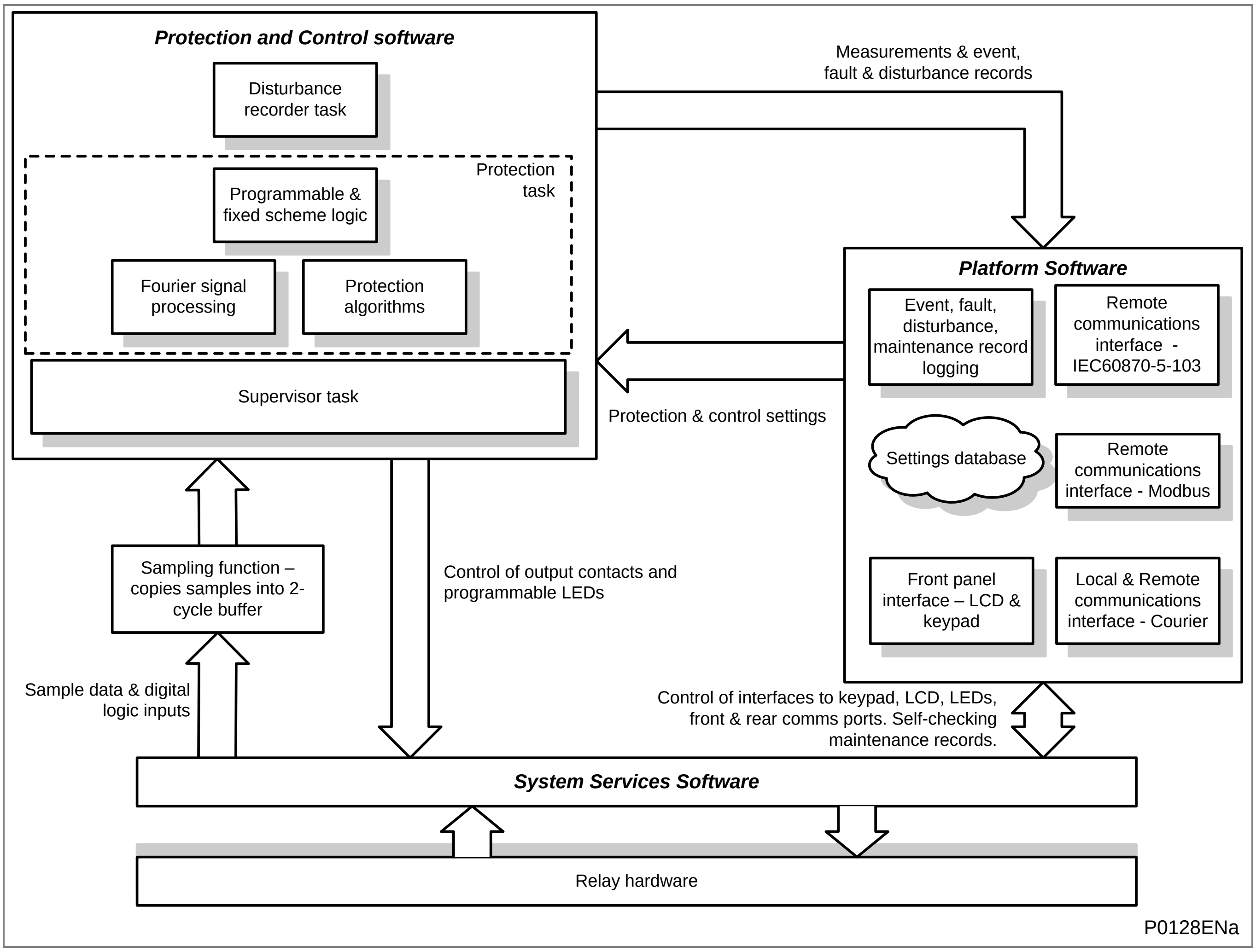


Figure 7 - Relay software structure

2.1 Real-Time Operating System

The real-time operating system provides a framework for the different parts of the relay's software to operate in.

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.

2.2 System Services Software

As shown in the above *Relay software structure* diagram, the system services software provides the low-level control of the relay hardware. It also provides the interface between the relay's hardware and the higher-level functionality of the platform software and the protection and control software.

For example, the system services software provides drivers for items such as the LCD display, the keypad and the remote communication ports. It also controls the boot of the processor and downloading of the processor code into SRAM from non-volatile flash EPROM at power up.

2.3 Platform Software

The platform software has these main functions:

- To deal with the management of the relay settings.
- To control the logging of all records that are generated by the protection software, including alarms and event, fault, disturbance 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. These interfaces are the front panel interface and the front and rear communication ports, using whichever communication protocol has been specified (Courier, MODBUS, IEC60870-5-103 and DNP3.0). The platform software converts the information from the database into the format required.

The platform software notifies the protection and control software of all settings changes and logs data as specified by the protection and control software.

2.3.1 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, and 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 functions. See also the section on *Self-Testing and Diagnostics* later in this section.

2.3.2 Settings Database

The settings database contains all of the settings and data for the relay, including the protection, disturbance recorder and control and support settings. The settings are maintained in non-volatile memory. The platform software's management of the settings database make sure that only one user interface modifies the database settings at any one time. This feature is used to avoid confusion 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 made in any order but applied to the protection elements, disturbance recorder and saved in the database in non-volatile memory, at the same time. If a setting change affects the protection and control task, the database advises it of the new values.

The database is directly compatible with Courier communications.

2.3.3 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.

2.4 Protection and Control Software

The protection and 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. It also 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 disturbance recorder.

The protection and control software task processes all of the protection elements and measurement functions of the relay. It has to communicate with both the system services software and the platform software, and organize its own operations. The protection software has the highest priority of any of the software tasks in the relay, to provide the fastest possible protection response. It also 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.

2.4.1 Overview - Protection and Control Scheduling

After initialization at start-up, the protection and control task waits until there are enough samples to process. The sampling function 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. Samples are taken 24 times every power cycle. Every 6 samples the protection task is executed (4 times per cycle). The protection elements are split into groups so that different elements are processed each time, and every element is processed at least once per cycle. 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.

2.4.2 Signal Processing

The sampling function filters the digital input signals from the opto-isolators and tracks the frequency of the analog signals. The digital inputs are checked against their previous value over a period of half a cycle. Therefore 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 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.

When the protection and control task is re-started by the sampling function, it calculates the Fourier components for the analog signals. 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, which is the most recent data. Used in this way, the DFT extracts the power frequency fundamental component from the signal and produces the magnitude and phase angle of the fundamental in rectangular component format. The DFT provides an accurate measurement of the fundamental frequency component, and effective filtering of harmonic frequencies and noise. This performance is achieved with the relay input module which provides hardware anti-alias filtering to attenuate frequencies above the half sample rate, and frequency tracking to maintain a sample rate of 24 samples per cycle. The Fourier components of the input current and voltage signals are stored in memory so 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.

2.4.3 Frequency Response

With the exception of the RMS measurements, all other measurements and protection functions are based on the Fourier-derived fundamental component. The fundamental component is extracted by using a 24-sample DFT. This gives good harmonic rejection for frequencies up to the 23rd harmonic. The 23rd is the first predominant harmonic that is not attenuated by the Fourier filter and this is known as an '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 the following *Frequency response* diagram.

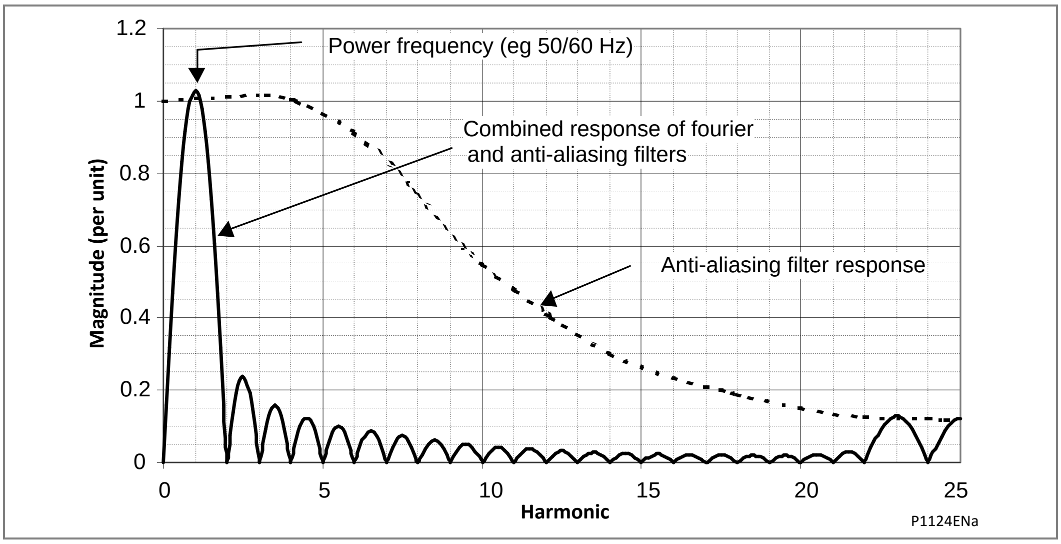


Figure 8 - Frequency response

For power frequencies that are not equal to the selected rated frequency, the harmonics are attenuated to zero amplitude. For small deviations of ±1Hz, this is not a problem but to allow for larger deviations, frequency tracking is used.

Frequency tracking automatically adjusts the sampling rate of the analog to digital conversion to match the applied signal. In the absence of a suitable signal to amplitude track, the sample rate defaults to the selected rated frequency (Fn). If the signal is in the tracking range of 40 to 70 Hz, the relay will lock on to the signal and the measured frequency will coincide with the power frequency as shown in the *Frequency response* diagram. The resulting outputs for harmonics up to the 23rd will be zero. The relay will frequency track off any voltage or current in the order VA/VB/VC/IA/IB/IC down to 10% Vn for voltage and 5%In for current.

2.4.4 Programmable Scheme Logic (PSL)

The Programmable Scheme Logic (PSL) allows the relay user to configure an individual protection scheme to suit their own particular application. This is done with 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 such as protection starts and trips, and the outputs of the fixed PSL. The fixed PSL provides the relay’s standard protection schemes. The PSL 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 or to condition the logic outputs, such as 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 Easergy Studio/MiCOM S1 Studio.

2.4.4.1 PSL Data

In the PSL editor in MiCOM S1 Studio, when a PSL file is downloaded to the relay the user can specify the group to download the file and a 32 character PSL reference description. This PSL reference is shown in the **Grp. 1/2/3/4 PSL Ref.** cell in the **PSL DATA** menu in the relay. The download date and time and file checksum for each group’s PSL file is also shown in the **PSL DATA** menu in cells **Date/Time** and **Grp. 1/2/3/4 PSL ID**. The PSL data can be used to show if a PSL has been changed and can be useful in providing information for version control of PSL files.

The default PSL Reference description is **Default PSL** followed by the model number, for example Default PSL **P34x??????0yy0?** where x refers to the model e.g. 1, 2, 3 and yy refers to the software version e.g. 05. This is the same for all protection setting groups (since the default PSL is the same for all groups). Since the LCD display (bottom line) only has space for 16 characters the display must be scrolled to see all 32 characters of the PSL Reference description.

The default date and time is the date and time when the defaults were loaded.

Note	*The PSL DATA column information is only supported by Courier and MODBUS, but not DNP3.0 or IEC60870-5-103.*

2.4.5 Function Key Interface (P343/P344/P345 only)

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 key press 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, allowing the function key state to be reinstated after power-up if the relay power is lost.

2.4.6 Event, Fault and Maintenance Recording

A change in any digital input signal or protection element output signal is used to indicate that an event has taken place. When this happens, the protection and control task sends a message to the supervisor task to show that an event is available to be processed. The protection and control task writes the event data to a fast buffer in SRAM that 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 supervisor’s buffer is faster than battery backed-up SRAM, therefore the protection software is not delayed waiting for the records to be logged by the platform software. However, if a large number of records to be logged are created in a short time, some may 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, an event is logged to indicate this loss of information.

Maintenance records are created in a similar manner with the supervisor task instructing the platform software to log a record when it receives a maintenance record message. However, it is possible that a maintenance record may be triggered by a fatal error in the relay, in which case it may not be possible to successfully store a maintenance record, depending on the nature of the problem. See the *Self-Testing and Diagnostics* section.

Fault records are stored in the sequence of events. They can be viewed locally or remotely and include:

- Faulty phase(s)
- Protection Tripped
- Protection Started
- Fault duration
- Fault type (internal or external fault)
- Operating time
- Primary or Secondary RMS values of prefault phase and neutral currents or angle of each winding
- Primary or Secondary RMS values of fault phase and neutral currents or angle of each winding
- Primary or Secondary RMS values of differential and biased current of each phase

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 with the disturbance recorder to allow the stored records to be extracted.

The disturbance recorder operates as a separate task from the protection and control task. It can record the waveforms for up to 9 analog channels and the values of up to 128 digital signals. The recording time is user selectable up to a maximum of 10.5 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 MICOM P391 ROTOR EARTH FAULT MEASURING/COUPLING UNIT

3.1 Introduction to MiCOM P391

The MiCOM P391 is a stand alone unit that measures earth faults of generator field windings, see the following illustration:

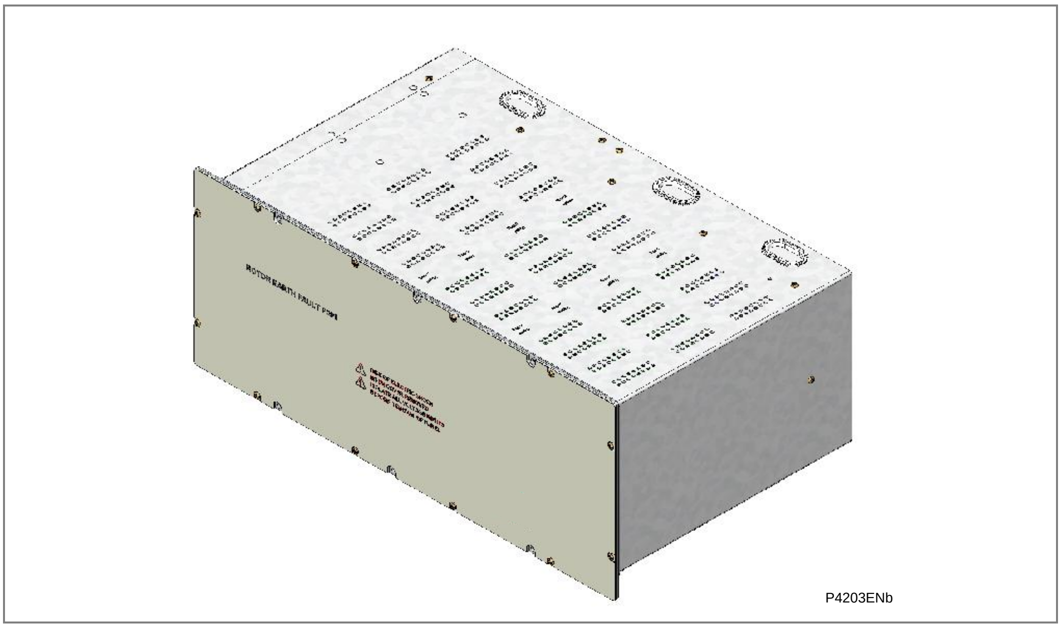


Figure 9 - P391 rotor earth fault measuring/coupling unit

The MiCOM P391 rotor earth fault protection device injects a DC voltage into the rotor circuit; the polarity of the voltage is reversed at low frequencies and the frequency is selectable by the user through a jumper link inside the device, 0.25 Hz, 0.5 Hz, 1 Hz. The voltage source is coupled to the excitation circuit via high resistance resistors. It is connected to the earthing brush of the rotor via a low resistance measuring shunt. The MiCOM P391 includes a watchdog contact to indicate any fault in the device. It also includes a 0-20 mA current loop output of the resistance measurement which is connected to the relay 0-20 mA current loop input to provide rotor earth fault alarm and trip stages.

Inside the P391 are three Printed Circuit Boards (PCBs), a description of these follow:

3.1.1 P391 Injection Resistor Boards

There are two injection resistor boards within the MiCOM P391. These couple the MiCOM P391 to the high voltage of the generator field winding.

The main injection resistors are accessible via terminal numbers A8 & A16 and B8 & B16. This circuit provides 5.8 kV isolation to earth allowing the P391 to be connected to generator field voltages of up to 1200 V DC.

The PCB also offers a 500 Ω calibration resistor for use during commissioning of the MiCOM P391. The calibration resistor is accessible via terminal numbers A3 & A5 or B3 & B5. This circuit provides 2 kV isolation to earth and the injection resistor circuit.

Warning	**Under no circumstances should the calibration resistors be connected to the generator field winding with the field voltage live. The calibration resistors must only be used during calibration of the MiCOM P391 to the MiCOM P342/P343/P344/P345 relay with the field voltage to the generator de-energized.**

Warning	**All voltage supplies must be isolated before the front cover or rear safety terminal cover is removed. This must be re-fitted before the supplies are restored**

3.1.2 P391 Power Supply, Control and Measurement Board

The board can be energized via terminal numbers C1 & C2. The power supply range is detailed in the table below:

Nominal range	Operative range
60 / 250 V dc	48 - 300 V dc
100 / 230 V (50-60 Hz)	85 – 253 V ac (45-65 Hz)

Table 3 - P391 power supply range

A power supply watchdog relay provides 1 changeover contact. These are accessible via terminal numbers C9, C10, and, C12 with the latter being the common contact.

Terminal C5 of the PCB provides the low frequency voltage output (±30 V DC Square wave output at 0.25 Hz, 0.5 Hz, or 1 Hz depending on injection frequency selected) that connects to the injection resistor boards and then to the generator field winding. The injection voltage frequency is selectable via an internal jumper on the PCB.

Terminal 6 provides the earth fault current return path from the generators earthing / grounding brush.

The returned fault current which represents the field winding fault resistance is fed through a measuring resistance, through a low pass filter, and conditioning circuit. The measured value is then converted to an output current in the range of 0-20 mA depending on the level of fault resistance to earth/ground in the generator field winding. This current output is available at terminals C17 & C18 of the board.

The output current circuit is classed as an Extra Low Voltage (ELV) circuit and is safe to touch under both normal operational use and single fault conditions.

The output current from terminals C17 & C18 is designed to be connected to the P342/P343/P344/P345 relays 0-20 mA CLIO input circuit which converts the current input back to a resistance representing the generator field winding fault resistance. The P342/P343/P344/P345 protection then uses this resistance value to execute its rotor earth fault protection application.

3.1.3 P391 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.

Medium duty terminal blocks are used for all connections.

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 front panel consists of a steel plate covered by a Schneider Electric branded membrane.

Ventilation holes are provided at the top and bottom of the case to allow cooling of the injection resistors. The case requires ventilation of the equivalent of 2U above and 1U below the case.

There are 3 mounting options available, these being, Rack, Panel or Wall which needs to be specified when ordering.

A rear terminal safety cover is also provided for all mounting options which must be fitted at all times.

4 SELF TESTING AND DIAGNOSTICS

The relay includes several 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 in the relay's hardware or software, the relay is able to detect and report the problem and attempt to resolve it by performing a reboot. The relay must therefore be out of service for a short time, during which the **Healthy** LED on the front of the relay is OFF and, the watchdog contact at the rear is ON. If the reboot fails to resolve the problem, the relay takes itself permanently out of service; the **Healthy** LED stays OFF and watchdog contact stays ON.

If a problem is detected by the self-monitoring functions, the relay stores a maintenance record in battery backed-up SRAM.

The self-monitoring is implemented in two stages:

- firstly a thorough diagnostic check that is performed when the relay is booted-up
- secondly a continuous self-checking operation that checks the operation of the relay's critical functions while it is in service.

4.1 Start-Up Self-Testing

The self-testing that 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 shown by the **Healthy** LED on the front of the relay which is ON when the relay has passed all tests and entered operation. If the tests detect a problem, the relay remains out of service until it is manually restored to working order.

The operations that are performed at start-up are:

- System Boot
- Initialization Software
- Platform Software Initialization and Monitoring

4.1.1 System Boot

The integrity of the flash memory is verified using a checksum before the program code and data are copied into SRAM and executed by the processor. When the copy is complete the data then held in SRAM is checked against that in flash memory to ensure they are the same and that no errors have occurred in the transfer of data from flash memory to SRAM. The entry point of the software code in SRAM is then called which is the relay initialization code.

4.1.2 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 initialization process the relay checks the following.

- The status of the battery
- The integrity of the battery backed-up SRAM that stores event, fault and disturbance records
- The voltage level of the field voltage supply that drives the opto-isolated inputs
- The operation of the LCD controller
- The watchdog operation

When the initialization software routine is complete, the supervisor task starts the platform software.

4.1.3 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.

4.2 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 section) and the results reported to the platform software.

The functions that are checked are as follows:

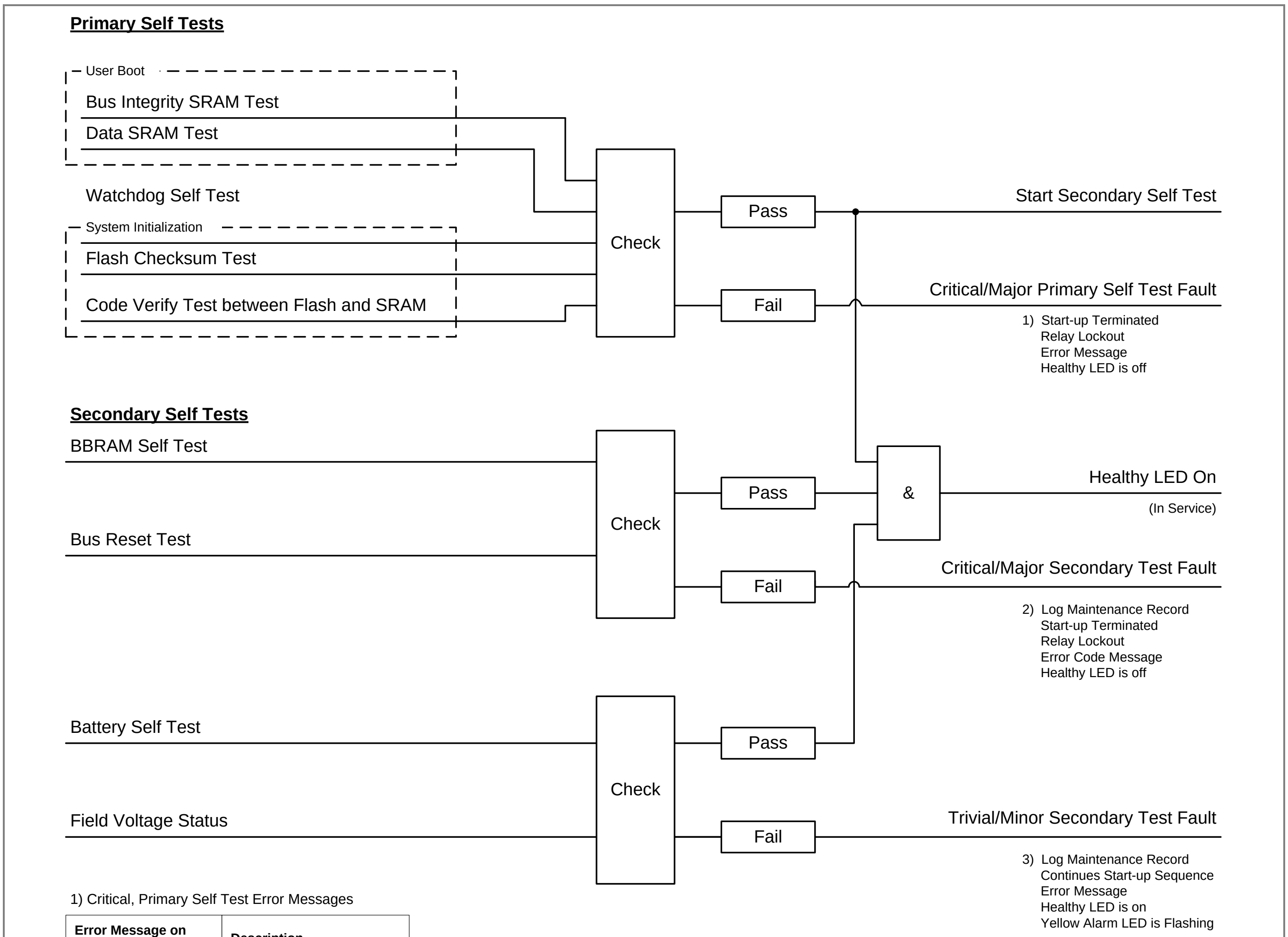
- The flash EPROM containing all program code and language text is verified by a checksum
- The code and constant data held in SRAM is checked against the corresponding data in flash EPROM to check for data corruption
- The SRAM containing all data other than the code and constant data is verified with a checksum
- The non-volatile memory containing setting values is verified by a checksum, whenever its data is accessed
- 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 checked by the acquisition function every time it is executed. This is done by sampling the reference voltage on a spare multiplexed channel
- 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

If the Ethernet board is fitted, it is checked by the software on the main processor board. If the Ethernet board fails to respond, an alarm is raised and the board is reset in an attempt to resolve the problem

In addition, the following checks may be made too:

- 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 correct operation of the CLIO board is checked, where it is fitted

In the unlikely event that one of the checks detects an error in 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 continues in operation. However, for problems detected in any other area the relay shuts down and reboots. This result in a period of up to 5 seconds when protection is unavailable, but the complete restart of the relay including all initializations should clear most problems that could occur. 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, the restart has not cleared the problem and the relay takes itself permanently out of service. This is indicated by the **Healthy** LED on the front of the relay which goes OFF, and the watchdog contact that goes ON.



1) Critical, Primary Self Test Error Messages

Error Message on User Interface	Description
Bus Fail	Integrity Bus Test Error
SRAM Fail	SRAM Test Error
Flash Fail (Checksum)	Flash Test Error detected in the flash structure
Code Verify Fail	Error in code comparison test flash
Watchdog fail	Watchdog circuit fails to operate

2) Critical, Secondary Self Test Error Messages

Error Code	Description
0x0C170017	The secondary self tests detected an error in the Battery Backed SRAM (BBRAM)
0x0C170018	The secondary self tests detected an error in the Bus Curcuit

3) Trivial, Secondary Power on Self Tests Alarm Indications

Alarm	Description
Battery Failure	The secondary self tests detected battery self test has failed
Field Volt Fail	The secondary self tests detected Field Voltage failure

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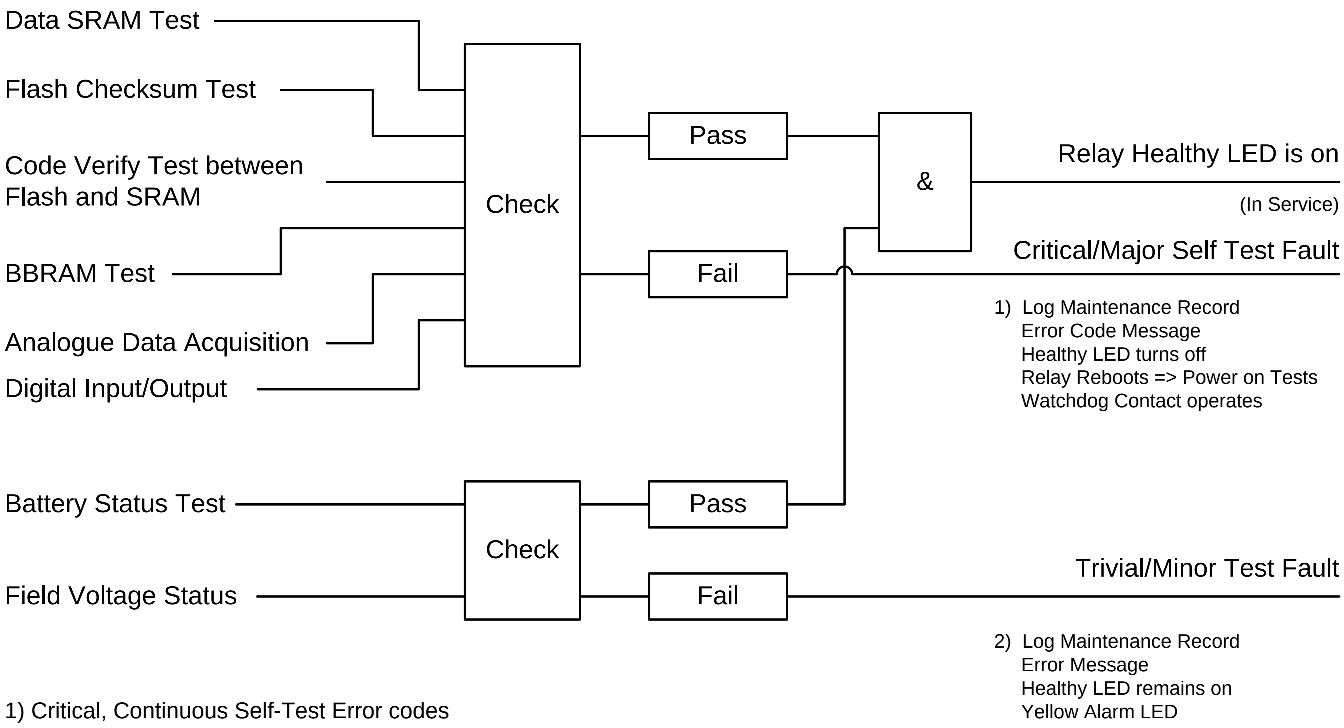
Figure 10 - Start-up self-testing logic



1) Critical, Continuous Self-Test Error codes

Error Code	Description
0x0C160011	The continuous self tests detected an error in SRAM
0x0C160012	The continuous self tests detected an error in the Flash memory checksum
0x0C160013	The continuous self tests detected an error in the code comparison
0x0C160014	The continuous self tests detected an error in the Battery Backed RAM
0x0C1600A0	The continuous self tests detected an error in the acquisition card
0x0C1600Bn	The continuous self tests detected an error in relay card n (number from 0)
0x0C1600Cn	The continuous self tests detected an error in opto card n (number from 0)

2) Trivial, Continuous Self-Test alarm indications

Error Code	Description
Battery Failure	The secondary self tests detected battery self test has failed
Field Volt Fail	The secondary self tests detected Field Voltage failure

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Figure 11 - Continuous self-testing logic

COMMISSIONING

CHAPTER 11

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

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FIGURES

TABLES

1 INTRODUCTION

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.*

The MiCOM P40 range of products includes various devices which have different functions. This chapter includes information related to the Commissioning of one or more of these devices. Many, although not all, of the commissioning tasks are common to these products.

This chapter applies to the MiCOM P40 products shown on the second page of this chapter. Where a particular section or paragraph relates only to one of more of the products, this is stated in the heading or at the beginning of the paragraph or section. If this states "Applicability: All", this means the following information relates to all the products in shown on the second page of this chapter. Otherwise the Applicability statement will list the MiCOM P40 products which the information covers.

When using this chapter, you (i.e. in your role as the Commissioning Engineer), need to be aware of:

- The MiCOM product number you are commissioning
- The features associated with that MiCOM product number
- The subset of features which have been enabled for the specific piece of equipment you are commissioning
- Any work instructions which determine how the equipment should be installed and which of its functions have been enabled and how they should relate to other equipment
- You will then be able to select which of the following sections/subsections you need to follow. Some of these sections will not be relevant for the particular commissioning tasks you are performing. By way of example, if the MiCOM device you are commissioning has an Auto-Reclose function you need to refer to the sections which cover Auto-Reclose, otherwise you can ignore them.
- You should start using this chapter at the beginning and work your way through to the end. At key points in the chapter, you will have to know what technical functions have been enabled, as you will be asked to omit certains sections of this chapter if they are not relevant for your current commissioning task.

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].

Warning	**Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information chapter/Safety Guide SFTY/5L M/L11 or later issue, the Technical Data chapter and the ratings on the equipment rating label.**

Caution	**The relay must not be disassembled in any way during commissioning.**

This chapter covers both the P34x & P391 generator protection relay range and the P391 Generator Rotor Earth Fault Protection Unit.

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.

Menu text	Default setting	Settings
COMMISSION TESTS		
Opto I/P Status	-	-
Relay O/P Status	-	-
Test Port Status	-	-
LED Status	-	-
Monitor Bit 1	64 (LED 1)	0 to 2047 See *P34x/EN PL* for details of Digital Data Bus signals
Monitor Bit 3	66 (LED 3)	
Monitor Bit 4	67 (LED 4)	
Monitor Bit 5	68 (LED 5)	
Monitor Bit 6	69 (LED 6)	
Monitor Bit 7	70 (LED 7)	
Monitor Bit 8	71 (LED 8)	
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
Red LED Status	-	-
Green LED Status	-	-

Table 1 - List of test facilities within Commission Tests menu

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 (PSL) 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.

Monitor bit	1	2	3	4	5	6	7	8
Monitor/download port pin	11	12	15	13	20	21	23	24

The required DDB signal numbers are 0 – 2047.

Table 2 - Monitor bits and download port pins

Warning — **The monitor/download port is not electrically 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 **COMMISSION TESTS** column) is used to allow secondary injection testing to be performed on the relay.

To select test mode set the Test Mode menu cell to '**Test Mode**'. It causes an alarm condition to be recorded, the yellow ALARM LED to light and an alarm message '**Test Mode Alm**' to be generated.

Test Mode freezes any information stored in the **CB CONDITION** column and (in IEC60870-5-103 builds) changes the Cause Of Transmission (COT) to Test Mode. For relays supporting IEC 61850 Edition 2, the test bit for data quality attribute shall set to TRUE, and the Logical Device Mode will set to test.

Test mode can also be enabled by energizing an opto mapped to the **Test Mode** signal.

To enable testing of output contacts set the **Test Mode** cell to **Contacts Blocked**. It causes an alarm condition to be recorded, the yellow ALARM LED to light and an alarm message '**Contacts Blk Alm**' to be generated.

In **Contact Blocked** mode, the protection function still works but the contacts will not operate. Also the **test pattern** and contact test functions are visible, which can be used to manually operate the output contacts. For relays supporting IEC 61850 Edition 2, the test bit for data quality attribute shall set to TRUE, and the Logical Device Mode will set to test/blocked.

Contacts Blocked can also be enabled by energizing an opto mapped to the **Contacts Blocked** signal.

Once testing is complete the cell must be set back to '**Disabled**' to restore the relay back to service.

WARNING	**If you use or enable Test Mode, you must disable Test Mode before putting the relay back into active service. IT IS POTENTIALLY EXTREMELY UNSAFE TO ATTEMPT TO USE ANY RELAY WHICH IS STILL IN TEST MODE IN ACTIVE SERVICE.**

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 Red LED Status and Green LED Status (P343/P344/P345 only)

The **Red LED Status** and **Green LED Status** cells are 18-bit binary strings that show which of the user-programmable LEDs on the relay are ON when accessing the relay from a remote location. **1** indicates a particular LED is ON and a **0** OFF. When the status of a particular LED in both cells is **1**, this means the LED is yellow.

2.11 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 Easergy test plug (if Easergy test block type 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 an RS232 port as well as appropriate software. This allows the rear communications port to be tested. If this is used, and it can save considerable time during commissioning.
- 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

5.1 Introduction to 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
- that it is functioning correctly and
- that 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.

If Programmable Scheme Logic (PSL) (other than the default settings with which the relay was 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 by 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.*

Warning	**Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information chapter/Safety Guide SFTY/5L M/L11 or later issue, the Technical Data chapter and the ratings on the equipment rating label.**

5.2 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 MiCOM P991 or an Easergy test block is provided, insert the Easergy or MiCOM P992 test plug, 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.

5.2.1 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.

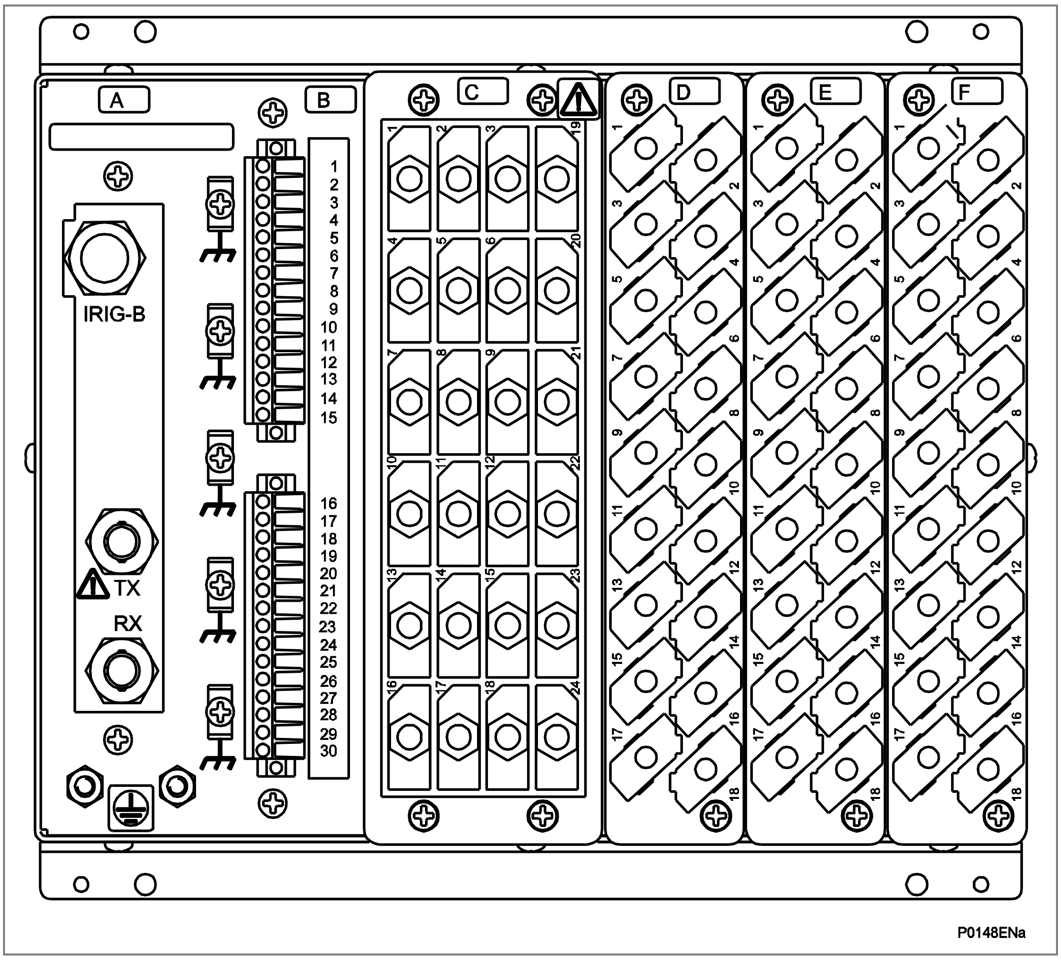

Figure 1 - Rear terminal blocks on size 40TE case

5.2.2 Current Transformer Shorting Contacts

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. The heavy duty terminal block location depends on the relay model.

- For P342 relays block reference C (40TE case) and D (60TE case) are heavy duty terminal blocks.
- For P343/P344/P345 relays they are located at block references C and E (60TE case) and D and F (80TE case).

Current Input	Shorting Contact between Terminals			
	P342 (40TE), P343 (60TE)		P342 (60TE), P343/P344/P345 (80TE)	
	1A CT's	5A CT's	1A CT's	5A CT's
IA	C3 - C2	C1 - C2	D3 - D2	D1 - D2
IB	C6 - C5	C4 - C5	D6 - D5	D4 - D5
IC	C9 - C8	C7 - C8	D9 - D8	D7 - D8
IN	C12 - C11	C10 - C11	D12 - D11	D10 - D11
IN SENSITIVE	C15 - C14	C13 - C14	D15 - D14	D13 - D14
IA(2) (P343/P344/P345 only)	E3 - E2	E1 - E2	F3 - F2	F1 - F2
IB(2) (P343/P344/P345 only)	E6 - E5	E4 - E5	F6 - F5	F4 - F5
IC(2) (P343/P344/P345 only)	E9 - E8	E7 - E8	F9 - F8	F7 - F8
I 100% STEF (P345 only)			F12 - F11	F10 - F11
C/S Voltage (P345 only)				F19-F20

Table 3 - Current transformer shorting contact locations

Heavy duty terminal blocks are fastened to the rear panel using four Pozidriv or PZ1 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.

Warning	***If external test blocks are connected to the relay, take great care when using the associated test plugs such as MMLB and MiCOM P992 since their use may make hazardous voltages accessible. 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.*

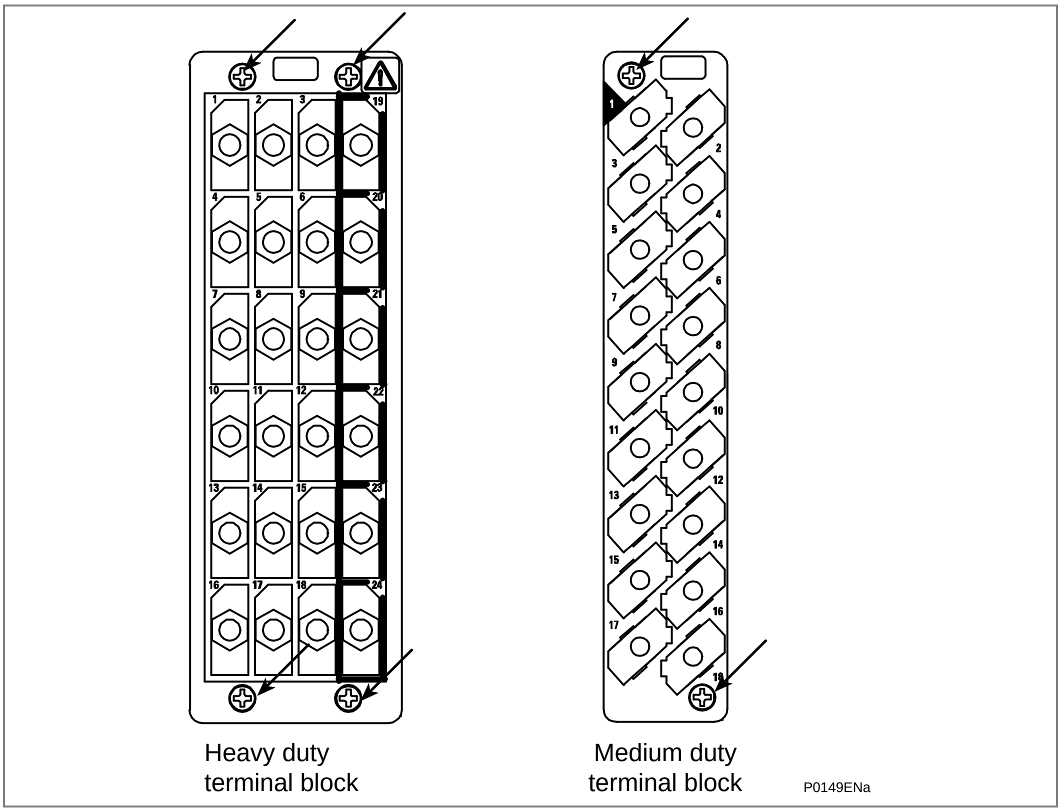

Figure 2 - Location of securing screws for heavy duty terminal blocks

5.2.3 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:

a) Voltage transformer circuits
b) Current transformer circuits
c) Auxiliary voltage supply
d) Field voltage output and opto-isolated control inputs
e) Relay contacts
f) EIA(RS)485 communication port
g) 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.

5.2.4 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 MiCOM P991 or an Easergy 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.

5.2.5 Watchdog Contacts

Using a continuity tester, check that the watchdog contacts are in the states shown in the *Watchdog contact statu*s table for a de-energized relay.

Terminals		Contact state	
		Relay de-energized	Relay energized
F11 - F12 J11 - J12 M11 - M12	(P342 40TE) (P342/P343 60TE) (P343/P344/P345 80TE)	Closed	Open
F13 - F14 J13 - J14 M13 - M14	(P342 40TE) (P342/P343 60TE) (P343/P344/P345 80TE)	Open	Closed

Table 4 - Watchdog contact status

5.2.6 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 Ranges	
dc	ac	dc	ac
24 - 32V dc	-	19 - 38V dc	-
48 - 110V dc	-	37 - 150V dc	-
110 - 250V dc	100 - 240V ac rms	87 - 300V dc	80 - 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.**

5.3 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.**

5.3.1 Watchdog Contacts

Using a continuity tester, check that the watchdog contacts are in the states shown in the *Watchdog contact statu*s table for a de-energized relay.

5.3.2 Liquid Crystal Display (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.**

5.3.3 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 or by using SNTP via Ethernet.

5.3.3.1 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 [DATE and TIME, IRIG-B Sync.] must be set to **Enabled**.

Ensure the relay is receiving the IRIG-B signal by checking that cell [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 [DATE and TIME, Date/Time] should be correct. Then reconnect the IRIG-B signal.

5.3.3.2 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.

5.3.4 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.

5.3.4.1 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.

5.3.4.2 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.

5.3.4.3 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.

5.3.5 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		
	P342 (40TE)	P342/P343 (60TE)	P343/P344/P345 (80TE)
+ve	F7 & F8	J7 & J8	M7 & M8
-ve	F9 & F10	J9 & J10	M9 & M10

Table 6 - Field voltage terminals

5.3.6 Input Opto-Isolators

This test checks that all the opto-isolated inputs on the relay are functioning correctly.

Model	Case	Opto-Insulated Inputs
P342	40TE	8-16
P342	60TE	16-24
P343	60TE	16-24
P343/P344/P345	80TE	24-32

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.

5.3.7 Output Relays

This test checks that all the output relays are functioning correctly.

Model	Case	Outputs
P342	40TE	7 to 15
P342	60TE	16 to 24
P343	60TE	14 to 22
P343/P344/P355	80TE	24 to 32

Ensure that the cell [xxxx: COMMISSIONING TESTS, Test Mode] is set to **Contacts Blocked**. (xxxx = 0F0E for P44x/P44y, 0F0D for P14x, P24x, P34x, P54x, P547, P64x or P841).

The output relays should be energized one at a time. To select output relay 1 for testing, set cell [xxxx: COMMISSIONING TESTS, Test Pattern] to 00000000000000000000000000000001. (xxxx = 0F0F for P44x/P44y, 0F0E for P14x, P24x, P34x, P445, P54x, P547, P64x or P841).

Connect a continuity tester across the terminals corresponding to output relay 1 as shown in the relevant external connection diagram in the *Installation* chapter.

To operate the output relay, set cell [xxxx: COMMISSIONING TESTS, Contact Test] to **Apply Test**. Operation is 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. (xxxx = 0F11 for P44x, 0F0F for P14x, P24x, P34x, P44y, P445, P54x, P547, P64x or P841).

Reset the output relay by setting cell [xxxx: COMMISSIONING TESTS, Contact Test] to **Remove Test**. (xxxx = 0F11 for P44x, 0F0F for P14x, P24x, P34x, P44y, P445, P54x, P547 or P64x).

Note	*Ensure that the 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. Keep the time between application and removal of contact test to a minimum.*

Repeat the test for the rest of the relays (the numbers depend on the model).

Return the relay to service by setting cell [0F0D: COMMISSIONING TESTS, Test Mode] to **Disabled**.

5.3.8 RTD Inputs

This test checks that all the RTD inputs are functioning correctly and is only performed on relays with the RTD board fitted.

A 100 Ω resistor, preferably with a tolerance of 0.1%, should be connected across each RTD in turn for PT100 and Ni100 RTDs and a 120 Ω resistor for Ni120 RTDs. The resistor needs to have a very small tolerance as RTDs complying to BS EN 60751 : 1995 typically have a change of resistance of 0.39 Ω per °C, therefore the use of a precision wire wound or metal film resistor is recommended. It is essential to connect the RTD common return terminal to the appropriate RTD input otherwise the relay will report an RTD error as it will assume that the RTD wiring has been damaged. The connections required for testing each RTD input are given in the *RTD input terminals* table.

Check that the corresponding temperature displayed in the **MEASUREMENTS 3** column of the menu is 0°C ±2°C. This range takes into account the 0.1% resistor tolerance and relay accuracy of ±1°C. If a resistor of lower accuracy is used during testing the acceptable setting range will need to be increased.

RTD	Terminal connections		Measurement cell (in “Measurements 3” Column (04) of Menu)
	Resistor between	Wire between	P34x
1	B1 and B2	B2 and B3	[0412: RTD 1 Label]
2	B4 and B5	B5 and B6	[0413: RTD 2 Label]
3	B7 and B8	B8 and B9	[0414: RTD 3 Label]
4	B10 and B11	B11 and B12	[0415: RTD 4 Label]
5	B13 and B14	B14 and B15	[0416: RTD 5 Label]
6	B16 and B17	B17 and B18	[0417: RTD 6 Label]
7	B19 and B20	B20 and B21	[0418: RTD 7 Label]
8	B22 and B23	B23 and B24	[0419: RTD 8 Label]
9	B25 and B26	B26 and B27	[041A: RTD 9 Label]
10	B28 and B29	B29 and B30	[041B: RTD 10 Label]

Table 8 - RTD input terminals

5.3.9 Current Loop Inputs

This test checks that all the current loop (analog) inputs are functioning correctly and is only performed on relays with the Current Loop Input Output (CLIO) board fitted.

For details of the relay terminal connections see the connection diagrams in the *Installation* chapter. Note that for the current loop inputs, the physical connection of the 0 to 1 mA input is different to that of the 0 to 10, 0 to 20, and 4 to 20 mA inputs, as shown in the connection diagrams.

An accurate dc current source can be used to apply various current levels to the current loop inputs. Another approach is to use the current loop output as a convenient and flexible dc current source to test the input protection functionality. Externally the current loop outputs can be fed into their corresponding current loop inputs. Then by applying a certain level of analog signal, such as V_A, to the relay the required dc output level can be obtained from the current loop output which is feeding the current loop input.

Enable the current loop input to be tested. Set the CLIx minimum and maximum settings and the CLIx Input type for the application.

Apply a dc current to the relay current loop input at 50% of the CLI input maximum range, 0.5 mA (0 to 1 mA CLI), 5 mA (0 to 10 mA CLI) or 10 mA (0 to 20, 4 to 20 mA CLI).

Check the accuracy of the current loop input using the MEASUREMENTS 3 - CLIO Input 1/2/3/4 column of the menu. The display should show (CLIx maximum + CLIx minimum)/2 ±1% full scale accuracy.

5.3.10 Current Loop Outputs

This test checks that all the current loop (analog) outputs are functioning correctly and is only performed on relays with the CLIO board fitted.

For details of the relay terminal connections, see the connection diagrams in the *Installation* chapter.

Note	*For the current loop outputs the physical connection of the 0 to 1 mA output is different to that of the 0 to 10, 0 to 20, and 4 to 20 mA outputs, as shown in the connection diagrams.*

Enable the current loop output to be tested. Set the CLOx parameter, CLOx minimum and maximum settings and the CLOx output type for the application. Apply the appropriate analog input parameter to the relay equals to (CLOx maximum + CLOx minimum)/2. The current loop output should be at 50% of its maximum rated output. Using a precision resistive current shunt and a high-resolution voltmeter, check that the current loop output is at 50% of its maximum rated output, 0.5 mA (0 to 1 mA CLO), 5 mA (0 to 10 mA CLO) or 10 mA (0 to 20, 4 to 20 mA CLO). The accuracy should be within ±0.5% of full scale + meter accuracy.

5.3.11 Rear Communications Port (First)

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:

- Section 5.3.12.1 - K-Bus Configuration
- Section 5.3.12.2 - EIA(RS)485 Configuration
- Section 5.3.12.3 - EIA(RS)232 Configuration

5.3.11.1 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	**MODBUS, VDEW or DNP3.0**	**P342 (40TE)**	**P342/P343 (60TE)**	**P343/P344/P345 (80TE)**
Screen	Screen	F16	J16	M16
1	+ve	F17	J17	M17
2	-ve	F18	J18	M18

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.

5.3.11.2 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.

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.

5.3.11.3 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.

5.3.11.4 DNP3.0 Communications

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.

5.3.11.5 IEC 61850 Communications

Connect a portable PC running the appropriate IEC61850 Master Station Software or MMS browser to the relay's Ethernet port (RJ45 or ST fiber optic connection). The terminal numbers for the relay's Ethernet port are shown in the following *Signals on the Ethernet connector* table.

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. If these parameters are not available from an SCL file, they must be configured manually.

If the assigned IP address is duplicated elsewhere on the same network, the remote communications operates in an indeterminate way. However, the relay checks for a conflict on every IP configuration change and at power-up. An alarm is 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.

Check that communications with this relay can be established.

To communicate with an IEC 61850 IED on Ethernet, it is necessary only to know its IP address. This can then be configured in either of the following:

- An IEC 61850 client (or master), such as a PACiS computer (MiCOM C264) or HMI
- An MMS browser, with which the full data model can be retrieved from the IED without any previous knowledge

Setting changes such as protection settings are not supported in the current IEC 61850 implementation. Such setting changes are done using MiCOM S1 Studio using the front port serial connection of the relay, or over the Ethernet link if preferred. This is known as tunneling. See the *SCADA Communications* chapter for more information on IEC 61850.

The connector for the Ethernet port is a shielded RJ45. The following 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 10 - Signals on the Ethernet connector

5.3.12 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:

5.3.12.1 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 11 - Second 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.

5.3.12.2 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 (Easergy Studio/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.

5.3.12.3 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 12 - 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.

5.3.13 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.**

Menu cell	P342 (40TE) P343 (60TE)		P342 (60TE) P343/P344/P345 (80TE)	
	Apply current to			
	1A CT's	5A CT's	1A CT's	5A CT's
[0201: MEASUREMENTS 1, IA Magnitude]	C3 - C2	C1 - C2	D3 - D2	D1 - D2
[0203: MEASUREMENTS 1, IB Magnitude]	C6 - C5	C4 - C5	D6 - D5	D4 - D5
[0205: MEASUREMENTS 1, IC Magnitude]	C9 - C8	C7 - C8	D9 - D8	D7 - D8
[0207: MEASUREMENTS 1, IN Measured Mag]	C12 - C11	C10 - C11	D12 - D11	D10 - D11
[020B: MEASUREMENTS 1, ISEF Magnitude]	C15 - C14	C13 - C14	D15 - D14	D13 - D14
[0401: MEASUREMENTS 3, IA-2 Magnitude]	E3 - E2 *	E1 - E2 *	F3 - F2 *	F1 - F2 *
[0403: MEASUREMENTS 3, IB-2 Magnitude]	E6 - E5 *	E4 - E5 *	F6 - F5 *	F4 - F5 *
[0405: MEASUREMENTS 3, IC-2 Magnitude]	E9 - E8 *	E7 - E8 *	F9 - F8 *	F7 - F8 *
Note * P343/P344/P345 only				

Table 13 - Current input terminals

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	*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 P741/P742/P743/P746). However, an additional allowance must be made for the accuracy of the test equipment being used.

	P34x
Menu cell (Measurements 1 unless otherwise stated)	**Corresponding CT ratio (in 'VT and CT RATIO column (0A) of menu)**
[0201: IA Magnitude] [0203: IB Magnitude] [0205: IC Magnitude]	$\frac{\text{[0A07 : Phase CT Primary]}}{\text{[0A08 : Phase CT Secondary]}}$
[0207: IN Measured Mag]	$\frac{\text{[0A09 : E/F CT Primary]}}{\text{[0A0A : E/F CT Sec'y]}}$
[020B: ISEF Magnitude]	$\frac{\text{[0A0B : SEF CT Primary]}}{\text{[0A0C : SEF CT Sec'y]}}$
[0401: Measurements 3, IA - 2 Magnitude] [0403: Measurements 3, IB - 2 Magnitude] [0405: Measurements 3, IC - 2 Magnitude]	$\frac{\text{[0A07 : Phase CT Primary]}}{\text{[0A08 : Phase CT Secondary]}}$ (P343/P344/P345 only)

Table 14 - CT ratio settings

5.3.14 Voltage Inputs

This test verifies the accuracy of voltage measurement is within the acceptable tolerances.

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.

Cell in Measurements 1 Column (02)	Voltage applied to	
	P342 40TE, P343 60TE	**P342 60TE, P343/P344/P345 80TE**
[021A: VAN Magnitude]	C19 - C22	D19 - D22
[021C: VBN Magnitude]	C20 - C22	D20 - D22
[021E: VCN Magnitude]	C21 - C22	D21 - D22
[0220: VN Measured Mag]	C23 - C24	D23 - D24
[0250: VN2 Measured Mag]		F23 - F24 (P344/P345 only)
[0270: C/S Voltage Mag]		F19 - F20 (P345 only)
* Voltage reference for synchrocheck		

Table 15 - Voltage input terminals

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%. However, an additional allowance must be made for the accuracy of the test equipment being used.

Cell in Measurements 1 column (02)	Corresponding VT Ratio (in 'CT and VT RATIO' column(0A) of menu)
	P34x
[021A: VAN Magnitude] [021C: VBN Magnitude] [021E: VCN Magnitude]	$\frac{\text{[0A01 : Main VT Primary]}}{\text{[0A02 : Main VT Secondary]}}$
[0220: VN Measured Mag]	$\frac{\text{[0A05 : VN VT Primary]}}{\text{[0A06 : VN VT Secondary]}}$
[0250: VN2 Measured Mag] (P344/P345 only)	$\frac{\text{[0A03 : VN2 VT Primary]}}{\text{[0A04 : VN2 VT Secondary]}}$
[0270: C/S Voltage Mag] (P345 only)	$\frac{\text{[0A16 : C/S VT Primary]}}{\text{[0A17 : C/S VT Secondary]}}$

Table 16 - 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.**

If the application-specific settings are not available, ignore sections 6.1 and 6.2.

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 laptop PC running the appropriate software (such as Easergy/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 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 Check Application-Specific 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:

6.3 Demonstrate Correct Relay Operation

Tests 5.2.13 and 5.2.14 have already demonstrated that the relay is within calibration, therefore the purpose of these tests is as follows:

- To confirm that the primary protection function of the P343/P344/P345 relay, the generator or generator-transformer differential protection, can trip according to the correct application settings.
- To verify correct setting of the backup phase overcurrent protection (P342/P343/P344/P345).
- To verify correct assignment of the trip contacts, by monitoring the response to a selection of fault injections.

6.3.1 Generator Differential Protection (P343/P344/P345)

To avoid spurious operation of any other protection elements, all protection elements except the generator differential protection should be disabled for the duration of the differential element tests. This is done in the relay's **CONFIGURATION** column. Make a note of which elements need to be re-enabled after testing. The generator differential protection is selected by the **SYSTEM CONFIG - Winding Config - Generator** setting.

For testing the biased differential protection select the **Biased** setting in the **GEN DIFF**, **Gen Diff Func** menu and perform the tests described in section 6.3.1.2, 6.3.1.3 and 6.3.2. For testing the high impedance differential protection select the **High Impedance** setting in the **GEN DIFF**, **Gen Diff Func** menu and perform the tests described in section 6.3.2.

The P343/P344/P345 generator differential protection has three elements, one for each phase. The biased differential protection uses the maximum bias current in the three phases to bias the elements. The detailed bias characteristic is described in sub-document - Installation. The following instructions are for testing the bias characteristic of the B phase element. The bias current is applied to the A-phase element.

6.3.1.1 Connect the Test Circuit

The following tests require a variable transformer and two resistors connected as shown in Figure 3. Alternatively an injection test set can be used to supply Ia and Ib currents.

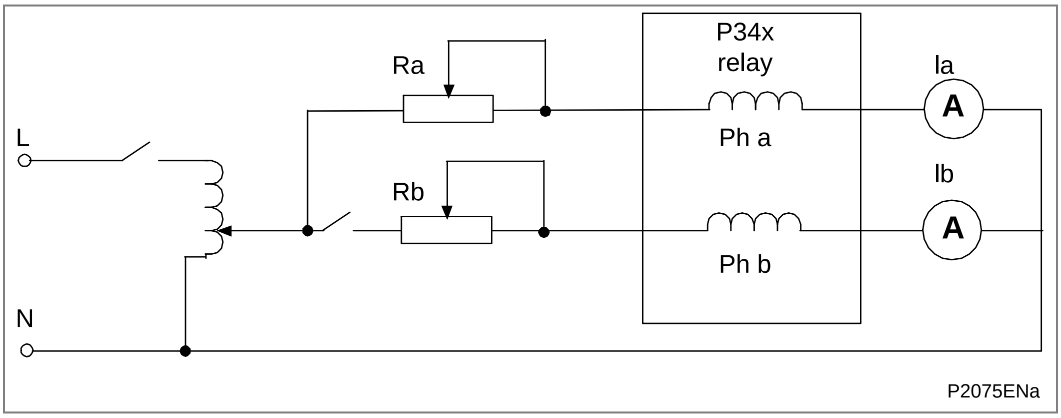

Figure 3 - Connection for testing

For the biased differential protection a current is injected into the A phase IA-2 input, (E3 - E2 (1A, 60TE case), E1 - E2 (5A, 60TE case), F3 - F2 (1A, 80TE case), F1 - F2 (5A, 80TE case)), which is used as the bias current, IBias = (IA + IA-2)/2 = IA-2/2 as IA=0. Another current is injected into the B phase IB-2 input (E6 - E5 (1A, 60TE case), E4 - E5 (5A, 60TE case), F6 - F5 (1A, 80TE case), F4 - F5 (5A, 80TE case)) which is used as the differential current, Differential = IB-2 - IB = IB-2 as IB=0. Ia is always greater than Ib.

6.3.1.2 Biased Differential Protection Lower Slope

If three LEDs have been assigned to give phase segregated trip information, Gen Diff Trip A, Gen Diff Trip B and Gen Diff Trip C (DDB 737, 738, 739), these may be used to indicate correct per-phase operation. If not, monitor options will need to be used - see the next paragraph.

Go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F05: **Monitor Bit 1**] to 737, [0F06: **Monitor Bit 2**] to 738 and [0F07: **Monitor Bit 3**] to 739. Cell [0F04: **Test Port Status**] will now appropriately set or reset the bits that now represent Phase A Trip (DDB 737), Phase B Trip (DDB 738) and Phase C Trip (DDB 739) with the rightmost bit representing Phase A Trip. From now on you should monitor the indication of [0F04: Test Port Status].

Adjust the variac and the resistor to inject 1 pu into IA-2 to give a bias current of 0.5 pu in the A-phase.

> *Note* *1pu = 1A into terminals E3 - E2 (60TE case), F3 - F2 (80TE case) for 1A applications; or 1 pu = 5A into terminals E1 - E2 (60TE case), F1-F2 (80TE case) for 5A applications).*

The relay will trip and any contacts associated with the A-phase will operate, and bit 1 (rightmost) of [0F04: **Test Port Status**] will be set to 1. Some LEDs, including the yellow alarm LED, will come on, but ignore them for the moment.

Slowly increase the current in the B-phase IB-2 input E6 - E5 (1A, 60TE), E4 - E5 (5A, 60TE case), F6 - F5 (1A, 80TE case), F4 - F5 (5A, 80TE case) until phase B trips (Bit 2 of [0F04: **Test Port Status**] is set to 1). Record the phase B current magnitude and check that it corresponds to the information in Table 17.

Switch OFF the ac supply and reset the alarms.

Bias current (IA-2/2)		Differential current (IB)	
Phase	Magnitude	Phase	Magnitude
A	0.5 pu	B	0.0 5 pu +/-10%

Table 17 - Biased differential lower scope test currents

Assumption: Is1 = 0.05 pu, k1 = 0%, Is2 = 1.2 pu

For other differential settings the formula below can be used (enter k1 slope in pu form, for example percentage/100):

B phase operate current is (Is1 + IBias x k1) pu +/- 10%

6.3.1.3 Biased Differential Protection Upper Slope

Repeat the test in 6.2.1.2 with the A phase, IA-2, current set to be 3.4 pu (Ibias = 1.7 pu).

Slowly increase the current in the B phase until phase B trips (bit 2 of [0F04: **Test Port Status**] is set to 1). Record the phase B current magnitude and check that it corresponds to the information in Table 18.

Switch OFF the ac supply and reset the alarms.

Bias current (IA-2/2)		Differential current (IB)	
Phase	Magnitude	Phase	Magnitude
A	1.7 pu	B	0.8 pu +/-20%

Table 18 - Biased differential upper scope test currents

Assumption: Is1 = 0.05 pu, k1 = 0%, Is2 = 1.2 pu, k2 =150%as above

For other differential settings the formula below can be used (enter k1 and k2 slopes in pu form, for example percentage/100):

Operate current is [(IBias x k2) + {(k1 - k2) x□ Is2 } + Is1] pu +/- 20%

Note	*Particularly for 5A applications the duration of current injections should be short to avoid overheating of the variac or injection test set.*

6.3.2 Generator Differential Operation and Contact Assignment

6.3.2.1 Phase A

Retaining the same test circuit as before, prepare for an instantaneous injection of 4 x Is1 pu current in the A phase, with no current in the B phase (B phase switch open). Connect a timer to start when the fault injection is applied, and to stop when the trip occurs.

Determine which output relay has been selected to operate when a Gen Diff Trip occurs by viewing the relay's PSL. The PSL can only be changed using the appropriate software. If this software is not available then the default output relay allocations will still be applicable. In the default PSL, relay 3 is the designated protection trip contact and DDB 736 Gen Diff Trip is assigned to this contact. If the generator differential trip is not mapped directly to an output relay in the PSL, output relay 3 (H5-H6 in the 60TE case and L5-L6 in the 80TE case) should be used for the test as relay 3 initiates the trip led.

Ensure that the timer is reset.

Apply a current of 4 x the setting in cell [3002: **GROUP 1 GEN DIFF**, **Gen Diff Is1**] to the relay and note the time displayed when the timer stops.

After applying the test check the red trip led and yellow alarm led turns on when the relay operates. Check 'Alarms/Faults Present - Tripped Phase A, Gen Diff Trip' is on the display. Reset the alarms.

Tripping	DDB Numbers	
Three Pole Tripping	DDB 736:	Gen Diff Trip
Single Pole Tripping	DDB 737: DDB 738: DDB 739:	Gen Diff Trip A Gen Diff Trip B Gen Diff Trip C

Table 19 - Generator differential protection DDBs

6.3.2.2 Phase B

Reconfigure the test equipment to inject fault current into the B phase. Repeat the test in 6.3.2.1 - Phase A, this time ensuring that the breaker trip contacts relative to B phase operation close correctly. Record the phase B trip time. Check the red trip led and yellow alarm led turns on when the relay operates. Check 'Alarms/Faults Present - Tripped Phase B, Gen Diff Trip' is on the display. Reset the alarms.

6.3.2.3 Phase C

Repeat 6.3.2.2 - Phase B for the C phase.

The average of the recorded operating times for the three phases should be less than 30 ms. Switch OFF the ac supply and reset the alarms.

On completion of the tests any protection elements which were disabled for testing purposes must have their original settings restored in the **CONFIGURATION** column.

6.3.3 Backup Phase Overcurrent Protection

The overcurrent protection function I>1 element should be tested.

To avoid spurious operation of any other protection elements all protection elements except the overcurrent protection should be disabled for the duration of the overcurrent element tests. This is done in the relay's **CONFIGURATION** column. Make a note of which elements need to be re-enabled after testing.

6.3.3.1 Connect the Test Circuit

Determine which output relay has been selected to operate when a I>1 trip occurs by viewing the relay's PSL.

The PSL 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 (that is 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 PSL, output relay 3 (H5 - H6 in the 60TE case and L5 - L6 in the 80TE case) should be used for the test as relay 3 initiates the trip LED. In the default PSL relay 3 is the designated protection trip contact and DDB 800 I>1 Trip is assigned to this contact.

Tripping	DDB Numbers	
Three Pole Tripping	DDB 800:	I>1 Trip
Single Pole Tripping	DDB 801: DDB 802: DDB 803:	I>1 Trip A I>1 Trip B I>1 Trip C

Table 20 - Overcurrent Protection DDBs

The associated terminal numbers can be found from the external connection diagrams in the Installation chapter *P34x/EN IN*.

Warning	**Connect the output relay so that its operation will trip the test set and stop the timer.**

Warning	**Connect the current output of the test set to the 'A' phase current transformer input of the relay (terminals C3 - C2 (1A, 60TE case), D3 - D2 (1A, 80TE case) C1 - C2 (5A, 60TE case), D1 - D2 (5A, 80TE case)).**

Ensure that the timer will start when the current is applied to the relay.

6.3.3.2 Perform the Test

Ensure that the timer is reset.

Apply a current of twice the setting in cell [3504: **GROUP 1 OVERCURRENT**, **I>1 Current Set**] to the relay and note the time displayed when the timer stops.

Check the red trip led and yellow alarm led turns on when the relay operates. Check 'Alarms/Faults Present - Started Phase A, Tripped Phase A, Overcurrent Start I>1, Overcurrent Trip **I**>1' is on the display. Reset all alarms.

Note	*The trip led is initiated from operation of relay 3, the protection trip contact in the default PSL.*

6.3.3.3 Check the Operating Time

Check that the operating time recorded by the timer is within the range in Table 21.

Note	*Except for the definite time characteristic, the operating times given in Table 21 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 21 must be multiplied by the setting of cell [3506: **GROUP 1 OVERCURRENT**, **I>1 TMS**] for IEC and UK characteristics or cell [3507: **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	[3505: I>1 Time Delay] setting	Setting ±5%
IEC S Inverse	10.03	9.53 - 10.53
IEC V Inverse	13.50	12.83 - 14.18
IEC E Inverse	26.67	25.34 - 28
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 21 - Characteristic operating times for I>1

On completion of the tests, any protection elements that were disabled for testing purposes must have their original settings restored in the **CONFIGURATION** column.

6.4 Generator-Transformer Differential Protection (P343/P344/P345)

To avoid spurious operation of any other protection elements, all protection elements except the transformer differential protection should be disabled for the duration of the differential element tests. This is done in the relay's **CONFIGURATION** column. The generator-transformer differential protection is selected by the **SYSTEM CONFIG - Winding Config - Xformer** setting and is enabled by the setting **DIFFERENTIAL - Xformer Diff Func -** Enabled. Make a note of which elements need to be re-enabled after testing.

The P343/P344/P345 transformer differential protection has three elements, one for each phase. The biased differential protection uses the maximum bias current in the three phases to bias the elements. The detailed bias characteristic is described in the Operation chapter *P34x/EN OP*.

6.4.1.1 Low Set Element Current Sensitivity (Xform I_{s1})

If three LEDs have been assigned to give phase segregated trip information, Xform Dif Trp A, Xform Dif Trp B and Xform IDiff Trp C (DDB 741, 742, 743), these may be used to indicate correct per-phase operation. If not, monitor options need to be used (see the next paragraph).

Go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F07: **Monitor Bit 1**] to 741, [0F08: **Monitor Bit 2**] to 742 and [0F09: **Monitor Bit 3**] to 743. Cell [0F05: **Test Port Status**] will now appropriately set or reset the bits that now represent Phase A Trip (DDB 741), Phase B Trip (DDB 742) and Phase C Trip (DDB 743) with the rightmost bit representing Phase A Trip. From now on, monitor the indication of [0F05: **Test Port Status**].

Connect the equipment so that current can be injected into the A phase IA-2 HV input, (E3 - E2 (1A, 60TE case), E1 - E2 (5A, 60TE case), F3 - F2 (1A, 80TE case), F1 - F2 (5A, 80TE case)). Slowly increase the current from 0 Amps and note the pick-up value at which the A phase biased differential element operates. Reduce the current slowly and note the drop-off value at which it resets. Check that the pick-up and drop-off are within the range shown in Table 22.

In Table 22, $I = \dfrac{Is \quad HS1}{amplitude \quad matching \quad factor}$

- Is1 is the low set setting which can be found in the cell Xform Is1 under the GROUP 1 DIFFERENTIAL PROTECTION menu heading. The amplitude matching factor is used to compensate for a mismatch in currents due to the line side current transformer ratios. There is one amplitude matching factor for the HV side, which is in the cell SYSTEM CONFIG -Match Factor HV and one for the LV side found in the cell **SYSTEM CONFIG - Match**
- **Factor LV.** Use the appropriate amplitude matching factor to calculate the current to inject: this depends on whether it is being injected into the HV or LV current transformer inputs.

	Current level
Pick-up	0.90 x I to 1.1 x I
Drop-off	0.90 x pick-up to 1 x pick-up

Table 22 - Low set element pick-up and drop-off

Repeat the above test for each of the remaining phases on the HV side, and for all three phases on the LV side. The connection terminals are shown in Table 13.

As the CT inputs to each phase have been verified by both the measurement checks and the low set differential trip checks, it is only necessary to check the operating time and the high set current sensitivity for each phase element on one side of the transformer.

6.4.1.2 Low Set Element Operating Time

Connect the relay so that current can be injected into the A phase IA-2 HV input, (E3 - E2 (1A, 60TE case), E1 - E2 (5A, 60TE case), F3 - F2 (1A, 80TE case), F1 - F2 (5A, 80TE case)). Connect a timer to start when the fault injection is applied, and to stop when the trip occurs.

Determine which output relay has been selected to operate when a Xform Dif Trp or Xform Bias Trp A/B/C occurs by viewing the relay's PSL. The PSL can only be changed using the appropriate software. If this software is not available then the default output relay allocations will still be applicable. In the default PSL, relay 3 is the designated protection trip contact and DDB 740 Xform Dif Trp is assigned to this contact. If the generator-transformer differential trip is not mapped directly to an output relay in the PSL, output relay 3 (H5-H6 in the 60TE case and L5-L6 in the 80TE case) should be used for the test as relay 3 initiates the trip led.

Ensure that the timer is reset.

Inject 4 x I into the HV side A phase. Check that the operating time for the relay is less than 33 ms. Repeat this test for both the remaining phases on the HV side. The current input terminals are shown in Table 13.

Tripping	DDB Numbers	
Three Pole Tripping	DDB 740:	Xform Dif Trp
Single Pole Tripping (Transformer Differential and Transformer Biased low set Differential protection)	DDB 741:	Xform Dif Trp A
	DDB 742:	Xform Dif Trp B
	DDB 743:	Xform Dif Trp C
	DDB 744:	Xform Bias Trp A
	DDB 745:	Xform Bias Trp B
	DDB 746:	Xform Bias Trp C

Table 23 - High set element sensitivity

6.4.1.3 High Set Element Current Sensitivity (Xform Is-HS1)

Warning The relay may be damaged by applying excessive current for long durations during testing, or in recurrent bursts without allowing time for the relay to cool down.

This test checks the instantaneous current sensitivity of the differential high set element. This test can only be performed if the test set can inject sufficient current into the relay to cause the element to trip at the calculated application setting.

The relay should be connected so that current can be injected into the A phase IA-2 HV input, (E3 - E2 (1A, 60TE case), E1 - E2 (5A, 60TE case), F3 - F2 (1A, 80TE case), F1 - F2 (5A, 80TE case)). Connect the output relay configured as Xform HS1 Trp A (DDB 747) to trip the test set and to stop a timer. Configure the test set so that when the current is applied to the relay, the timer starts.

Warning It is important to trip the test set to avoid sustained application of excessive currents.

It is recommended that the low set differential is still enabled during this test. The timer should be started when the current is applied to the relay. As the setting is above the continuous current rating of the relay, DO NOT INCREASE THE CURRENT SLOWLY, since this may damage the relay before it can operate. Instead, set the current level then suddenly apply it. Two tests have to be performed for this particular protection function. These are shown in Table 24.

Is HS1 (Trip)	Is HS1 (No Trip)
1.1 x I	0.90 x I

Table 24 - High set element sensitivity

The first test to be performed is at the higher current level, to check that the instantaneous element operates.

In Table 22, $I = \dfrac{I_{s1}}{amplitude \ \ matching \ \ factor}$ Is-HS1 is the high set setting which is in the cell **Xform Is HS1** under the **GROUP 1 DIFF PROTECTION** menu heading. The amplitude matching factor is used to compensate for a mismatch in currents due to the line side current transformer ratios. This is found in the cell **Match Factor HV** under the **GROUP 1 SYSTEM CONFIG** menu heading.

Inject 1.1 x I and ensure that the selected output relay operates.

Warning **For the second test it is important that the current is not applied for longer than one second.**

Inject 0.9 x I for one second and ensure that the selected output relay does not operate. Repeat the above two tests for the two remaining elements of the HV side of the transformer. The current input terminals are shown in Table 13.

Tripping	DDB Numbers	
Three Pole Tripping	DDB 740:	Xform Dif Trp
Single Pole Tripping (Transformer Differential high set 1 protection)	DDB 747: DDB 748: DDB 749:	Xform HS1 Trp A Xform HS1 Trp B Xform HS1 Trp C

Table 25 - Transformer differential protection DDBs

6.4.1.4 High Set Element Operating Time

This test can only be performed if the test set can inject sufficient current into the relay to cause the element to trip at the calculated application setting.

Connect the relay so that current can be injected into the A phase IA-2 HV input, (E3 - E2 (1A, 60TE case), E1 - E2 (5A, 60TE case), F3 - F2 (1A, 80TE case), F1 - F2 (5A, 80TE case)). Connect a timer to start when the fault injection is applied, and to stop when the trip occurs. Configure the test set so that when the current is applied to the relay, the timer starts.

Determine which output relay has been selected to operate when a Xform Dif Trp or Xform HS1 Trp A/B/C occurs by viewing the relay's PSL. The PSL can only be changed using the appropriate software. If this software is not available then the default output relay allocations will still be applicable. In the default PSL, relay 3 is the designated protection trip contact and DDB 740 Xform Dif Trp is assigned to this contact. If the generator-transformer differential trip is not mapped directly to an output relay in the PSL, output relay 3 (H5-H6 in the 60TE case and L5-L6 in the 80TE case) should be used for the test as relay 3 initiates the trip led.

Ensure that the timer is reset.

Inject 1.2 x I into the HV side A phase. Check that the operating time for the relay is less than 25 ms.

Repeat this test for both the remaining phases on the HV side. The current input terminals are shown in Table 13.

6.4.2 Differential Through Stability by Primary Injection

To check for through stability, it is preferable, especially for a new transformer installation to simulate a through-fed external fault, by a real primary fault simulation. This is achieved by placing a three-phase bolted short circuit on the downstream side of the LV CTs, and energizing the HV winding from a three-phase medium voltage supply. Typically, the HV winding is energized only from a voltage rated in the range 400 to 440 V, to limit the through fault current. In such a through fault situation, the relay should not trip.

Note	*The procedure for primary testing is not covered here, as it must respect utility safety rules, permits to work, and sanctions for testing.*

6.4.3 CT Secondary Wiring Differential through Stability Test by Secondary Injection

Secondary injection can be used to verify settings. For a two-winding transformer, a fault current flowing out of the LV side is simulated, with a balancing set of currents on one or two phases flowing into the HV side. If all settings and CT orientations are correct, no trip should occur, and minimal differential current is measured by the relay.

Warning	During these tests, disable all the current operated protection functions except the transformer differential protection. Make a note of all the functions that must be enabled after the testing is completed.

6.4.3.1 Yy Transformers and Autotransformer

This test simulates current flowing through the transformer to an external fault.

Consider a two-winding Yy0 transformer application, and that IA-2 (E3 - E2 (1A, 60TE case), E1 - E2 (5A, 60TE case), F3 - F2 (1A, 80TE case), F1 - F2 (5A, 80TE case)) is assigned to the HV winding and IA (C3 - C2 (1A, 60TE case), C1 - C2 (5A, 60TE case), D3 - D2 (1A, 80TE case), D1 - D2 (5A, 80TE case)) is assigned to the LV winding. A fault current is injected, flowing out of phase A at the LV terminals. The same zero sequence filtering setting is applied for the HV and LV windings; therefore, if the current simulated is 1 pu out of IA at the LV connections, the input current to balance IA at the HV connections is also 1 pu.

Connect the test equipment as shown in Figure 4 for a Yy0 transformer connection:

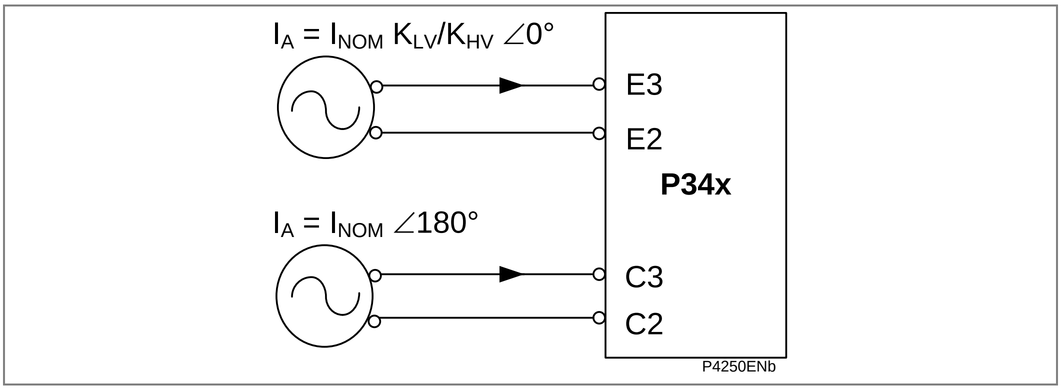

Figure 4 - Test equipment connection for a Yy0 transformer (1A and 60TE)

A single phase current equal to the CT secondary rating (1 A or 5 A) is simulated to flow OUT on phase A, LV CT connections. On an automatic test set, use INOM ∠180º.

To balance, a current is applied to one phase input of the HV CT connections. The magnitude should be a current equal to (K_{LV} / K_{HV}) x I_{NOM}, and at a phase angle as shown in Table 26:

	LV CT injected phase	LV current	HV CT injected phase	HV current
Yy0, Autotransformer	A	INOM ∠180º	A	I_{NOM} . K_{LV} / K_{HV} ∠0º
Yy2	A	INOM ∠180º	C	I_{NOM} . K_{LV} / K_{HV} ∠180º
Yy4	A	INOM ∠180º	B	I_{NOM} . K_{LV} / K_{HV} ∠0º
Yy6	A	INOM ∠180º	A	I_{NOM} . K_{LV} / K_{HV} ∠180º
Yy8	A	INOM ∠180º	C	I_{NOM} . K_{LV} / K_{HV} ∠0º
Yy10	A	INOM ∠180º	B	I_{NOM} . K_{LV} / K_{HV} ∠180º

Table 26 - Injected current for Yy ends

The amplitude matching factors K_{HV} and K_{LV} can be found in **Match Factor HV** and **Match Factor LV** respectively under the **GROUP 1 SYSTEM CONFIG** menu heading.

Apply the fault currents for approximately one second. If the HV CT connections and LV CT connections are in the correct orientation no trip should occur. It is important to read the displayed differential currents **IA Differential**, **IB Differential** and **IC Differential** under the **MEASUREMENT 3** menu heading to check that these measurements are low. These measurements must show less than 0.1 pu (10%), to prove that a balance is achieved.

The reason that the differential currents must be read is that in certain applications the Idiff> trip threshold may be set higher than I_{nom}, so that even an incorrect CT connection would not cause a trip.

It is not necessary to repeat the injection for other phases, because their orientation has already been checked in section 5.3.13, Current Inputs.

Figure 5 shows the transformer connections for the configurations shown in Table 2.

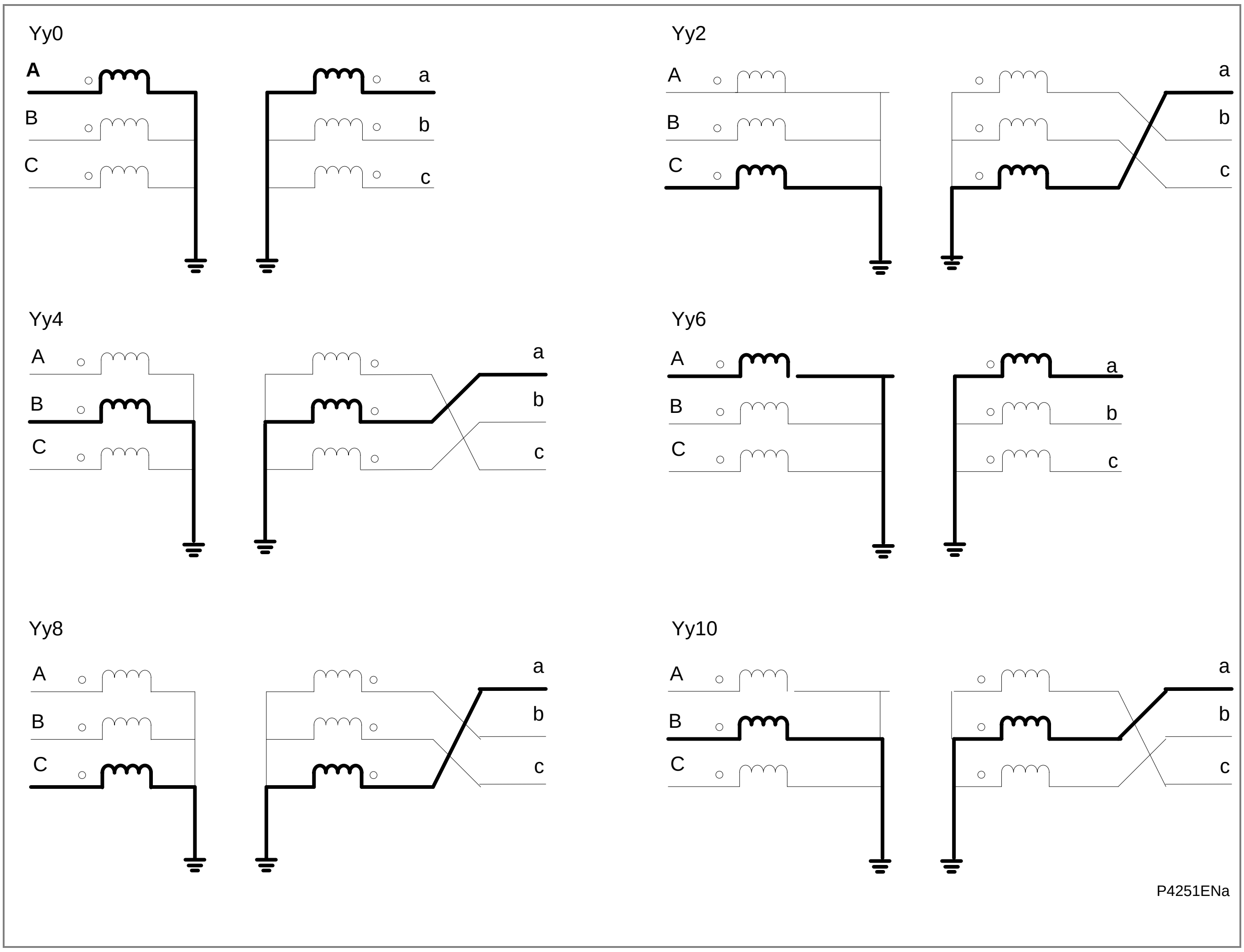

Figure 5 - Yy transformer connections

6.4.3.2 Dy and Yd Applications

This test simulates current flowing through the transformer to an external fault.

A fault current flowing out of the A phase on whichever winding is the star (wye) end is injected. For a Dy configuration it is the LV side, for a Yd configuration it is the HV side. The star winding phase A shares the same power transformer limb as two phases on the opposite side, so that a two-phase current loop needs to be injected to achieve a balance.

For ease of injection, a single phase current equal to the CT secondary rating (1 A or 5 A) is simulated to flow OUT on phase A of the wye end. On an automatic test set, use INOM $\angle 180^o$. To balance, a current is applied to two phase CT inputs (delta side). Table 27 shows the currents to be injected. The magnitude should be a current equal to [K_{wye} / ($\sqrt{3}.K_{delta}$)] x I_{NOM}, and at the phase angles as shown below:

	Star end injected phase	Current (Star)	Delta side injected loop	Current
Dy1 or Yd11	A	INOM $\angle 180^o$	A-C	IA = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 0^o$ IC = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 180^o$
Dy3 or Yd9	A	INOM $\angle 180^o$	C-B	IC = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 0^o$ IB = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 180^o$
Dy5 or Yd7	A	INOM $\angle 180^o$	A-B	IA = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 0^o$ IB = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 180^o$
Dy7 or Yd5	A	INOM $\angle 180^o$	A-C	IA = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 0o$ IC = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 180^o$
Dy9 or Yd3	A	INOM $\angle 180^o$	B-C	IB = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 0^o$ IC = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 180^o$
Dy11 or Yd1	A	INOM $\angle 180^o$	A-B	IA = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 0^o$ IB = I_{NOM} . K_{WYE} / $\sqrt{3}K_{DELTA}$ $\angle 180^o$

Table 27 - Injected current for delta-star ends

For a Yd1 configuration, connect the test equipment as shown in Figure 6.

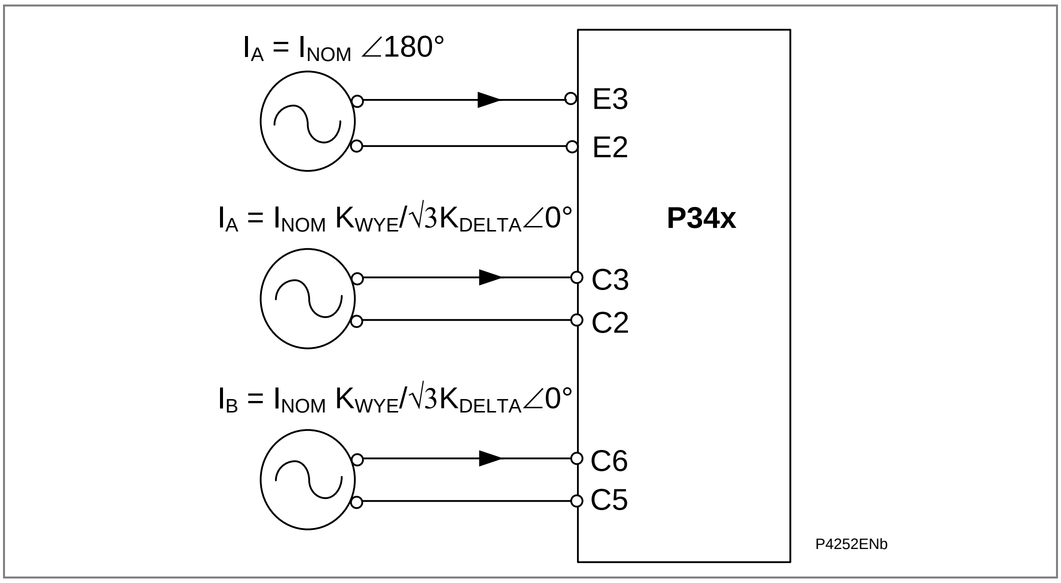

Figure 6 - Test equipment connection for a Yd1 transformer (1A and 60TE)

The amplitude matching factors K_{wye} and K_{delta} can be found in **Match Factor HV** and **Match Factor LV** under the **GROUP 1 SYSTEM CONFIG** menu heading

The delta side loop current may be applied as two separate current outputs from a test set, or one current looped out through the first phase specified, and returning back through the latter phase input.

Apply the fault currents for approximately one second. If the HV CT connections and LV CT connections are in the correct orientation no trip should occur. It is important to read the displayed differential currents **IA Differential**, **IB Differential and IC Differential** under the **MEASUREMENT 3** menu heading to check that these measurements are low. These measurements must show less than 0.1 p.u. (10%), to prove that a balance is achieved.

It is not necessary to repeat the injection for other phases, because their orientation has already been checked in section 5.3.13, Current Inputs.

Figure 7 shows a Yd9 transformer with the current distribution for an AN external fault on the Y side of the transformer. During the test shown in Figure 6, the following current distribution occurs in the P34x & P391.

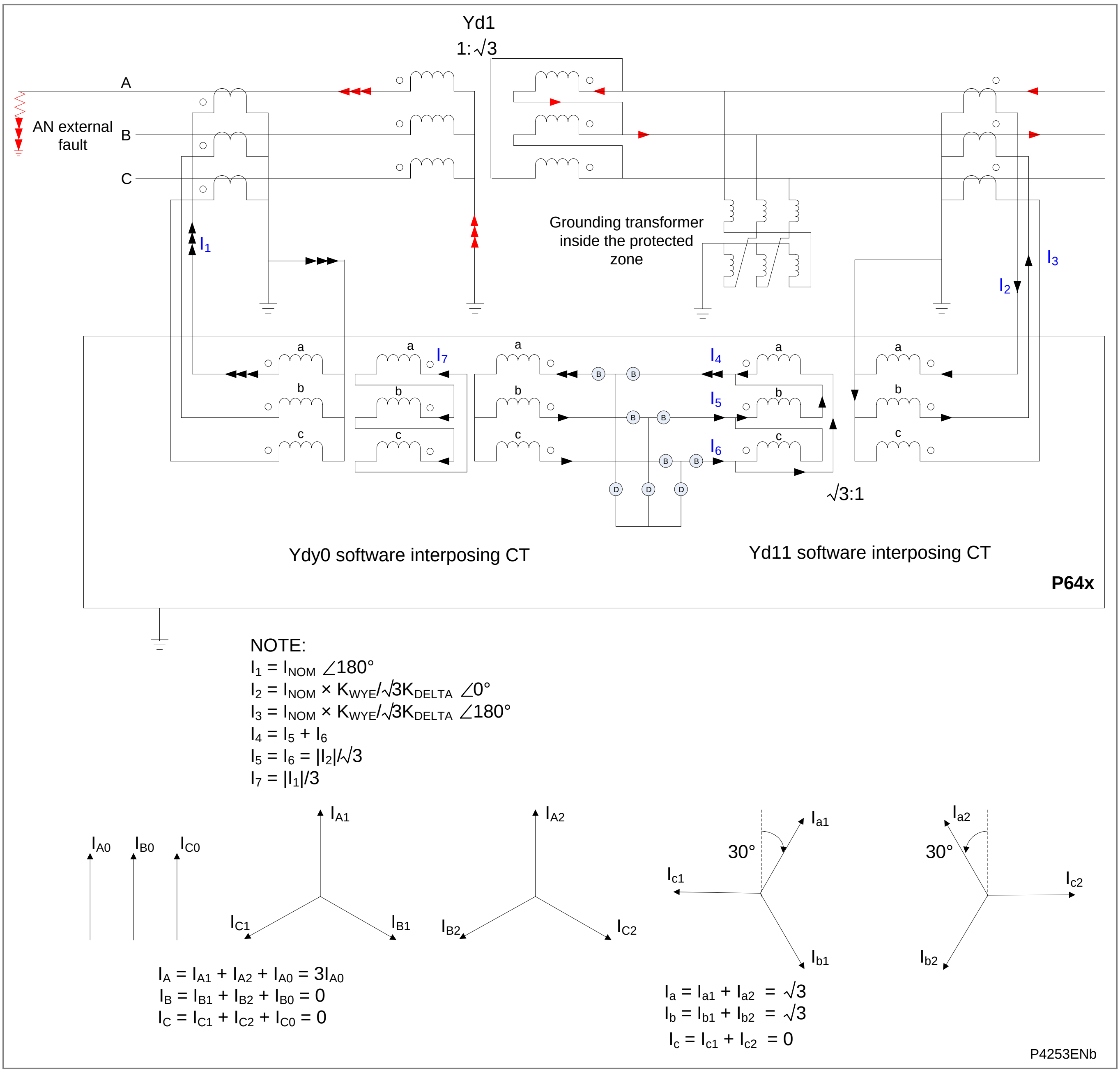

Figure 7 - Yd9 configuration AN external fault current distribution

Figure 8 shows the transformer connections for the configurations shown in Table 27.

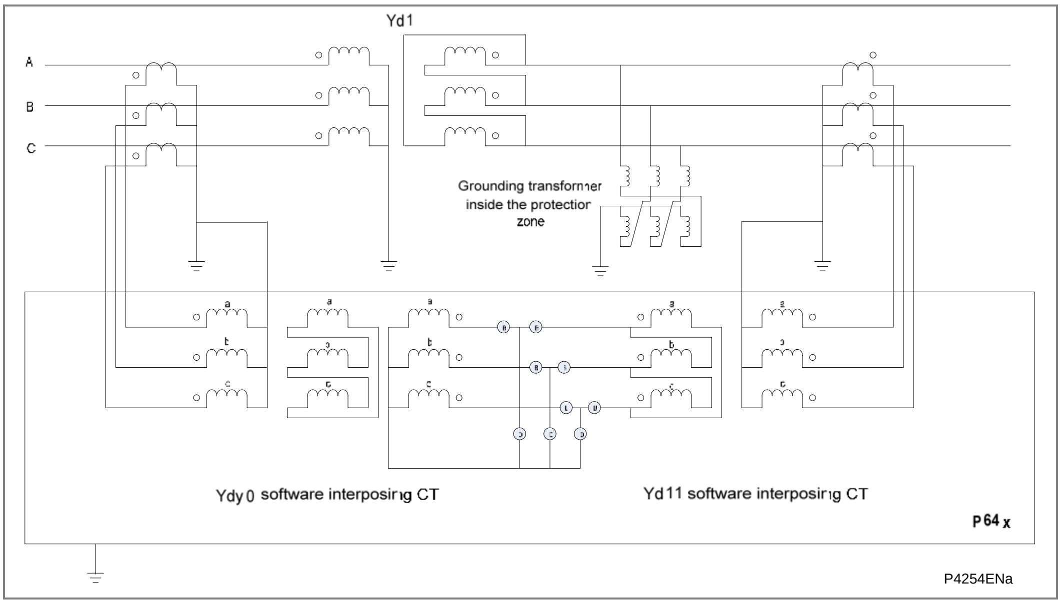

Figure 8 - Yd transformer connections

6.4.3.3 Dd Applications

This test simulates current flowing through the transformer to an external fault.

In many such applications, there may be in-zone earthing transformers, so it is easier to simulate an external phase-phase fault, to avoid simulating a zero sequence current. If the HV CT connection is assigned to the HV end and LV CT connection to the LV end, and the current simulated is 1 pu out of LV CT connection, the input current to balance at HV CT connection is easy to determine. In the simplest application of a Dd0 transformer, an A-B fault is simulated flowing out of the LV side, fed by an A-B loop input on the HV side.

For ease of injection, a loop current equal to the CT secondary rating (1 A or 5 A) is simulated to flow OUT on phase A, LV CT connection, and looping back through phase B, LV CT connection. On an automatic test set, use $I_{NOM} \angle 180^o$. Because four-phase CT inputs to the relay are energized at once, it is necessary that the test set output current for this LV side is set as a single phase but looping through two phase CT inputs.

To balance, a loop current is applied at HV CT (the HV winding). The magnitude should be a current equal to (K_{LV}/K_{HV}) x I_{NOM}, and at a phase angle as shown below. The test set is configured to generate only one single phase output for this winding, looped through two phase CT inputs. Therefore in total, the output requirements can be satisfied by a test set typically having only up to three current outputs.

	LV CT injected phase	LV current terminal 5 CT	HV CT injected phase	HV current terminal 1 CT
Dd0	A-B	$I_{NOM} \angle 180^o$	A-B	$I_{NOM} .\ K_{LV} / K_{HV} \angle 0^o$
Dd2	A-B	$I_{NOM} \angle 180^o$	C-B	$I_{NOM} .\ K_{LV} / K_{HV} \angle 0^o$
Dd4	A-B	$I_{NOM} \angle 180^o$	C-A	$I_{NOM} .\ K_{LV} / K_{HV} \angle 0^o$
Dd6	A-B	$I_{NOM} \angle 180^o$	B-A	$I_{NOM} .\ K_{LV} / K_{HV} \angle 0^o$
Dd8	A-B	$I_{NOM} \angle 180^o$	B-C	$I_{NOM} .\ K_{LV} / K_{HV} \angle 0^o$
Dd10	A-B	$I_{NOM} \angle 180^o$	A-C	$I_{NOM} .\ K_{LV} / K_{HV} \angle 0^o$

Table 28 - Current injected for Dd ends

The amplitude matching factors K_{HV} and K_{LV} can be found in **Match Factor HV** and **Match Factor LV** respectively under the **GROUP 1 SYSTEM CONFIG** menu heading.

For the Dd0 configuration, connect the test equipment as shown in Figure 9.

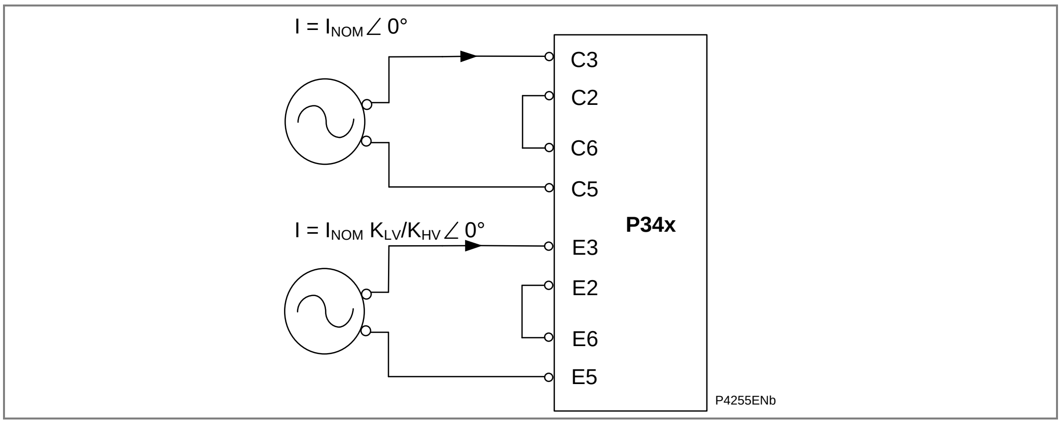

Figure 9 - Test equipment connection for a Dd0 transformer (1A and 60TE)

Apply the fault currents for approximately one second. If the HV CT connection and the LV CT connections are in the correct orientation no trip should occur. It is important to read the displayed differential currents **IA Differential**, **IB Differential** and **IC Differential** under the **MEASUREMENT 3** menu heading to check that these measurements are low. These measurements must show less than 0.1 p.u. (10%), to prove that a balance is achieved.

It is not necessary to repeat the injection for other phases, because their orientation has already been checked in section 5.3.13, Current Inputs.

Figure 10 shows the transformer connections for the configurations shown in Table 6.

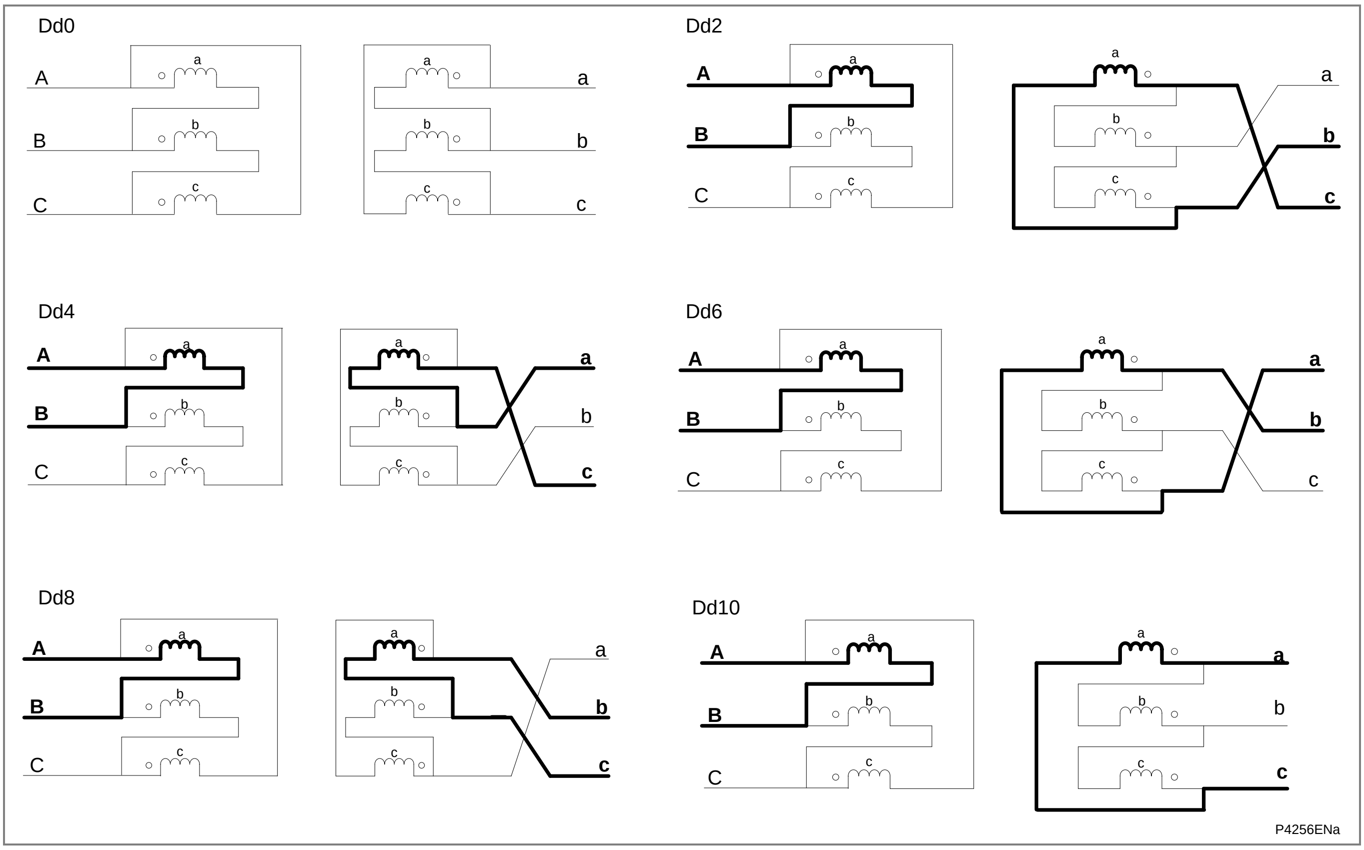

Figure 10 - Dd transformer connections

6.4.4 Low Set Element Bias Characteristic

This test checks the low set element bias characteristic. The relay has a three slope bias characteristic, therefore this test is performed at three points on the bias curve, one at 0% slope, at 30% slope, and at 80% slope, corresponding with bias currents of 0.4 p.u., 0.8 p.u., and 1.5 p.u. respectively.

If three LEDs have been assigned to give phase segregated trip information, Xform Dif Trp A, Xform Dif Trp B and Xform IDiff Trp C (DDB 741, 742, 743), these may be used to indicate correct per-phase operation. If not, monitor options need to be used (see the next paragraph).

Go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F07: **Monitor Bit 1**] to 741, [0F08: **Monitor Bit 2**] to 742 and [0F09: **Monitor Bit 3**] to 743. Cell [0F05: **Test Port Status**] will now appropriately set or reset the bits that now represent Phase A Trip (DDB 741), Phase B Trip (DDB 742) and Phase C Trip (DDB 743) with the rightmost bit representing Phase A Trip. From now on, monitor the indication of [0F05: **Test Port Status**].

It is important in this case that the injected currents are 180º out of phase. Connect the relay to the test equipment as shown in Figure 11.

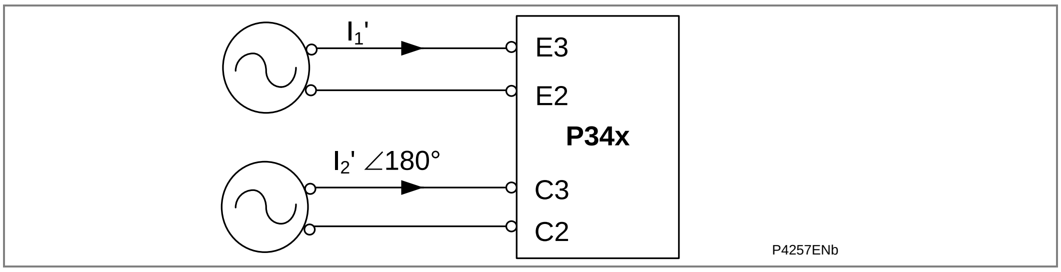

Figure 11 - Low set element bias characteristic test equipment connection(1A and 60TE)

In total, six tests should be performed, one to cause the relay to trip and one not to cause the relay to trip, for the three sections of the bias curve. From Table 29, select the appropriate current values for each test, depending on the setting and rating of the relay. Using the equations below, calculate the current values to apply to the relay, (I1' and I2'). In all cases the current should be applied for no longer than one second, and should be within ±5% of the calculated values.

K_{CT1} is the HV CT amplitude matching factor and K_{CT2} is the LV CT amplitude matching factor which are found in the cell **Match Factor HV** and **Match Factor LV** under the **GROUP 1 SYSTEM CONFIG** menu heading.

$I_1' = \frac{I_1}{K_{CT1}}$	$I_2' = \frac{I_2}{K_{CT2}}$

In (amps)	Is1 (pu)	0%				K1 = 30%				K2 = 80%			
		Trip		No trip		Trip		No trip		Trip		No trip	
		I1	I2	I1	I2	I1	I2	I1	I2	I1	I2	I1	I2
1	0.2	0.51	0.29	0.49	0.31	0.94	0.67	0.91	0.69	1.89	1.12	1.82	1.19
5	0.2	2.55	1.45	2.45	1.55	4.7	3.35	4.55	3.45	9.45	5.6	9.1	5.95

Table 29 - Low set element bias characteristic test

6.4.5 Second-Harmonic Blocking

This test checks that the second harmonic blocking is functioning, and it requires a current source capable of generating second-harmonic current. Once enabled, it blocks the low set differential element if the percentage of second harmonic over fundamental component per phase basis exceeds the setting Ih(2)%>.

To run the test, proceed as follows:

1. Connect two current test sources to one phase of any current bias input. Figure 12 shows the current sources connected to A phase of current bias input 1:

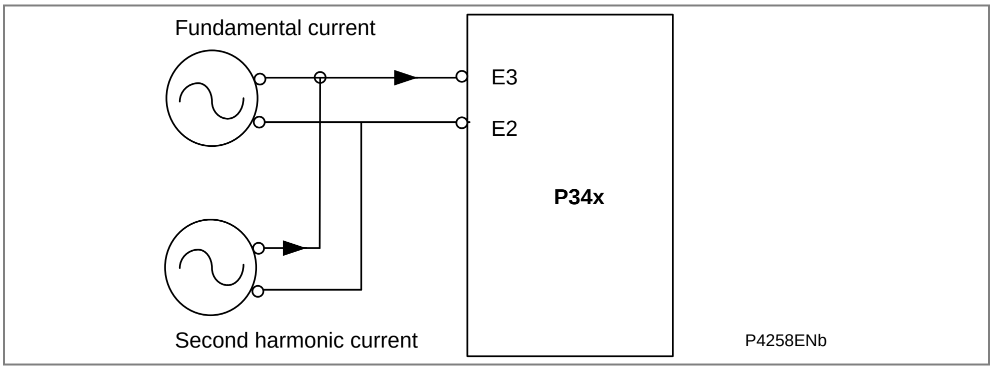

Figure 12 - Second harmonic test(1A and 60TE)

2. Inject 4 x I of fundamental current, where:

   $$I = \frac{I_{S1}}{K_{CT1}}$$

   Is1 is the low set setting, KCT1 is the HV CT amplitude matching factor which is used to compensate for a mismatch in currents due to the line side current transformer ratios. This is found in the cell **Match Factor HV** under the **GROUP 1 SYSTEM CONFIG** menu heading.
3. Ensure that Xform Bias Trp A [DDB 744] asserts.
4. Apply and ramp second-harmonic current to dropout the low set differential element.
5. Turn on the second current source for second-harmonic current (120 Hz if Frequency = 60 and 100 Hz if Frequency = 50). Starting at zero current, slowly increase the magnitude of this second current source until Xform Bias Trp A [DDB 744] resets.
6. Note the value of the applied current from the second test source. The current from the second-harmonic source is shown by:

   $$\text{Second harmonic current} = \frac{Ih(2)\%}{100} \times \text{fundamental current} \pm 10\%$$

6.4.6 Fifth-Harmonic Blocking

This test checks that the fifth-harmonic blocking is functioning, and it requires a current source capable of generating fifth-harmonic current. Once enabled, it blocks the low set differential element if the percentage of fifth harmonic over fundamental component per phase basis exceeds the setting Ih(5)%>.

Connect two current test sources to one phase of any current bias input. Figure 13 shows the current sources connected to current bias input 1.

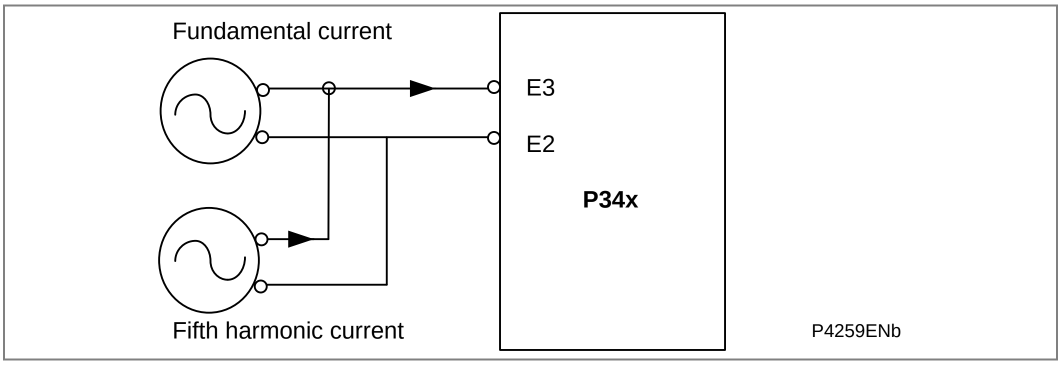

Figure 13 - Fifth-harmonic (1A and 60TE)

Inject 4 x I of fundamental current, where:

$$I = \frac{I_{s1}}{K_{CT1}}$$

Is1 is the low set setting. K_{CT1} is the HV CT amplitude matching factor which is used to compensate for a mismatch in currents due to the line side current transformer ratios. This is found in the cell **Match Factor HV** under the **GROUP 1 SYSTEM CONFIG** menu heading. Ensure that Xform Bias Trp A [DDB 744] asserts.

Apply and ramp fifth-harmonic current to dropout the low-set differential element. Turn on the second current source for fifth-harmonic current (300 Hz if Frequency = 60, 250 Hz if Frequency = 50). Starting at zero current, slowly increase the magnitude of this second current source until Xform Bias Trp A [DDB 744] resets. Note the value of the applied current from the second test source. The current from the fifth-harmonic source is given by:

$$\text{Fifth harmonic current} = \frac{Ih(5)\%}{100} \times \text{fundamental current}$$

6.4.7 Generator 100% Stator Earth Fault Protection via Low Frequency Injection (P345)

The 100% stator earth fault protection function via low frequency injection (64S) should be tested in the P345. The 100% stator earth fault protection via low frequency injection includes an overcurrent trip (64S I>1) an under resistance trip (64S R<2) and an under resistance alarm (64S R<1) element. It is only necessary to test the elements being used.

To avoid spurious operation of any other protection elements all protection elements except the 100% stator earth fault protection should be disabled for the duration of the 100% stator earth fault tests. This is done in the relay's **CONFIGURATION** column. Make a note of which elements need to be re-enabled after testing.

6.4.7.1 Connect the Test Circuit

Determine which output relay has been selected to operate when a 64S I>1 Trip (DDB 778) and 64S R<2 Trip (DDB 779) and 64S R<1 Alarm Trip (DDB 382) occurs by viewing the relay's PSL.

The PSL can only be changed using the appropriate software. If this software is not available then the default output relay allocations will still be applicable.

If the 64S protection signals are not independently mapped directly to an output relay in the PSL, output relay 3 and 4 (L5 - L6 and L7 - L8 in the P345) could be used in the default PSL to check the operation of the protection functions. In the default PSL relay 3 is the designated protection trip contact and 64S I>1 Trip (DDB 778) and 64S R<2

Trip (DDB 779) are assigned to this contact. In the default PSL relay 4 is the designated general alarm contact and 64S R<1 Alarm Trip (DDB 382) is assigned to this contact. Note, in the default PSL relay 3 is set to operate the Any Trip signal (DDB 674) which initiates the trip LED.

The associated terminal numbers can be found from the external connection diagrams in chapter *P34x/EN IN*.

Warning	**Connect the output relay so that its operation will trip the test set and stop the timer.**

Warning	**Connect a 20 Hz current output of the test set to the 'I 100% STEF' current transformer input of the relay (terminals F12 - F11 (1A), F10 - F11 (5A)). Note, for the 5A inputs the 64S I Magnitude measurement in the Measurements 3 menu will show 5 times lower current than being injected.**

Connect a 20 Hz voltage output of the test set to the 'V 100% STEF' voltage transformer input of the relay (terminals F21 - F22).

To simulate a generator standstill condition there should be no signal injected into the 3 phase voltage and current inputs.

Ensure that the timer will start when the current and voltage is applied to the relay.

6.4.7.2 Check the Pick-Up Settings

Ensure that the following settings [**GROUP 1 100% STATOR EF**, **64S R Factor** = 1, **64S Series R** = 0, **64S Parallel G** = 0, **64S Angle Comp** = 0, **64S R<1 Alarm** = **Disabled**, **64S R<2 Trip** = **Disabled**, **64S Supervision** = **Disabled**, **VN 3rd Harmonic** = **Disabled**.]

If three LEDs have been assigned to give the 64S alarm and trip information, 64S I>1 Trip (DDB 778), 64S R<2 Trip (DDB 779) and 64S R<1 Alarm Trip (DDB 382), these may be used to indicate correct operation. If not, monitor options will need to be used - see the next paragraph.

Go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F05: **Monitor Bit 1**] to 778, [0F06: **Monitor Bit 2**] to 779 and [0F07: **Monitor Bit 3**] to

382. Cell [0F04: Test Port Status] will now appropriately set or reset the bits that now represent 64S I>1 Trip (DDB 778), 64S R<2 Trip (DDB 779) and 64S R<1 Alarm Trip (DDB 382), with the rightmost bit representing 64S I>1 Trip. From now on you should monitor the indication of [0F04: **Test Port Status**].

Slowly increase the 20 Hz current to the I 100% STEF input F12 - F11 (1A), F10 - F11 (5A) until the 64S I> 1 element trips.

(Bit 3 of [0F04: **Test Port Status**] is set to 1). Record the 20Hz current magnitude and check that it corresponds to the 64S I>1 Trip Set ±5%.

Note	*The 5A inputs the **64S I Magnitude** measurement in the **Measurements 3** menu will show 5 times lower current than being injected.*

Switch OFF the test and reset the alarms.

Set **64S R<2 Trip** = **Enabled** and **64S R<1 Alarm** = **Disabled** and **64S Overcurrent** = **Disabled**.

Set the 20 Hz voltage to the V 100% STEF input, F21 - F22, to 20 V angle 0.

Slowly increase the 20 Hz current, angle 0, to the I 100% STEF input, F12 - F11 (1A), F10 - F11 (5A) until the 64S R<2 element trips.

(Bit 2 of [0F04: **Test Port Status**] is set to 1). Record the 20 Hz current and voltage magnitude and check that the resistance (R = V/I) corresponds to the 64S R<2 Trip Set ±5%.

Switch OFF the test and reset the alarms.

Set **64S R<1 Alarm** = **Enabled** and **64S R<2 Trip** = **Disabled** and **64S Overcurrent** = **Disabled**.

Set the 20 Hz voltage to the V 100% STEF input, F21 - F22, to 20 V angle 0.

Slowly increase the 20 Hz current, angle 0, to the I 100% STEF input, F12 - F11 (1A), F10 - F11 (5A) until the 64S R<1 element trips.

(Bit 3 of [0F04: **Test Port Status**] is set to 1). Record the 20 Hz current and voltage magnitude and check that the resistance (R = V/I) corresponds to the 64S R<1 Alm Set ±5%.

Switch OFF the test and reset the alarms.

6.4.7.3 Perform the Timing Tests

Ensure that the timer is reset.

Set 64S R<2 Trip = **Disabled** and **64S R<1 Alarm** = **Disabled** and **64S Overcurrent** = **Enabled**.

Apply a 20 Hz current of twice the setting in cell [3C44: GROUP 1 **100% STATOR EF**, **64S I>1 Trip Set]** to the relay and note the time displayed when the timer stops.

Check the red trip led and yellow alarm led turns on when the relay operates. Check 'Alarms/Faults Present - Started Phase N, Tripped Phase N, 100% 64S Start I>1, 100% 64S Trip I>1' is on the display. Reset all alarms. In the default PSL relay 3 is set to operate the Any Trip signal (DDB 674) which initiates the trip LED.

Check that the operating time recorded by the timer is within the range, 64S I>1 Trip Dly setting ±2% or 1.2 s whichever is greater with the P345 bandpass filter enabled and ±2% or 0.22 s whichever is greater with the P345 bandpass filter disabled. The P345 bandpass filter is automatically enabled when the system frequency is <45 Hz or it can be permanently enabled using DDB 555, 64S Filter On.

Allowance must also be made for the accuracy of the test equipment being used.

Ensure that the timer is reset.

Set **64S R<2 Trip** = **Enabled** and **64S R<1 Alarm** = **Disabled** and **64S Overcurrent** = **Disabled**.

Apply a 20 Hz voltage of 20 V, angle 0 and a 20 Hz current, angle 0 to give half the setting in cell [3C2C: GROUP 1 **100% STATOR EF**, **64S R<2 Trip Set**] to the relay and note the time displayed when the timer stops.

Check the red trip led and yellow alarm led turns on when the relay operates. Check 'Alarms/Faults Present - Started Phase N, Tripped Phase N, 100% 64S Start R<2, 100% 64S Trip R<2' is on the display. Reset all alarms.

Note	*In the default PSL relay 3 is set to operate the Any Trip signal (DDB 674) which initiates the trip LED.*

Check that the operating time recorded by the timer is within the range, **64S R<2 Trip Dly** setting ±2% or 1.2 s whichever is greater with the P345 bandpass filter enabled and ±2% or 0.22 s whichever is greater with the P345 bandpass filter disabled. The P345 bandpass filter is automatically enabled when the system frequency is <45 Hz or it can be permanently enabled using DDB 555, 64S Filter On.

Allowance must also be made for the accuracy of the test equipment being used.

Ensure that the timer is reset.

Set **64S R<2 Trip** = **Disabled** and **64S R<1 Alarm** = **Enabled** and **64S Overcurrent** = **Disabled**.

Apply a 20 Hz voltage of 20 V, angle 0 and a 20 Hz current, angle 0 to give half the setting in cell [3C20: GROUP 1 **100% STATOR EF**, **64S R<1 Alm Set**] to the relay and note the time displayed when the timer stops.

Check the yellow alarm led turns on when the relay operates. Check 'Alarms/Faults Present -100% 64S Alarm R<1' is on the display. Reset all alarms.

Check that the operating time recorded by the timer is within the range, **64S R<1 Alm Dly** setting ±2% or 1.2 s whichever is greater with the P345 bandpass filter enabled and ±2% or 0.22 s whichever is greater with the P345 bandpass filter disabled. The P345 bandpass filter is automatically enabled when the system frequency is <45 Hz or it can be permanently enabled using DDB 555, 64S Filter On.

Allowance must also be made for the accuracy of the test equipment being used.

Ensure that the timer is reset.

6.4.7.4 Perform the 100% Stator Earth Fault Supervision Test

Set the **64S Supervision** = **Enabled**, Set **64S R<2 Trip** = **Enabled and 64S R<1 Alarm** = **Enabled** and **64S Overcurrent** = **Enabled**.

In the default PSL the 64S Fail (DDB 1298) supervision signal is connected to the 64S Fail Alarm (DDB 383) signal. The 64S Fail signal is an output from the 64S supervision element and the 64S Fail Alarm signal triggers the alarm led and alarm message. For applications where the 20 Hz generator is powered by the VT it may be desirable not to alarm every time the generator is off line so the supervision element and alarm have separate DDBs. The 64S Fail signal is also connected to the 64S I>1 Inhibit, 64S R<1 Inhibit and 64S R<2 Inhibit in the default PSL.

If an LED has been assigned to give the 64S Fail Alarm or 64S Fail information, 64S Fail Alarm (DDB 383), this may be used to indicate correct operation. If not, monitor options will need to be used - see the next paragraph.

Go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F08: **Monitor Bit 4**] to 383 and cell [0F09: **Monitor Bit 5**] to 1076. Cell [0F04: **Test Port Status**] will now appropriately set or reset the bit that now represent 64S Fail Alarm (DDB 383) and 64S Fail (DDB 1298). From now on you should monitor the indication of [0F04: **Test Port Status**].

Apply a 20 Hz current and 20 Hz voltage above the settings in cell [3C50/54: GROUP 1 **100% STATOR EF**, **64S V <1 Set**, **64S V<1 Set**] but below the **64SI>1 Trip**, **64S R<2 Trip** and **64S R<1 Alarm** settings.

Set the voltage to half the **64S V<1 Set** and the current to half the **64S I< Set** and check the 64S Fail Alarm and 64S Fail operates and that there is no operation of the **64SI>1 Trip**, **64S R<2 Trip** and **64S R<1 Alarm** elements. (Bit 4 and 5 of [0F04: **Test Port Status**] is set to 1 and bits 1, 2, 3 = 0)

Check the yellow alarm led turns on when the relay operates. Check 'Alarms/Faults Present - 64S Fail Alarm' is on the display. Reset all alarms.

Check that the operating time recorded by the timer is within the range, **64S Superv'n Dly** setting ±2% or 1.2s whichever is greater with the P345 bandpass filter enabled and ±2% or 0.22 s whichever is greater with the P345 bandpass filter disabled. The P345 bandpass filter is automatically enabled when the system frequency is <45 Hz or it can be permanently enabled using DDB 555, 64S Filter On.

Allowance must also be made for the accuracy of the test equipment being used.

On completion of the tests any protection elements that were disabled for testing purposes must have their original settings restored in the **CONFIGURATION** column.

6.4.7.5 64S Calibration Procedure

The 100% stator earth fault protection can be calibrated with the machine at standstill, because the measuring principle for the earth resistance calculation is independent of whether the machine is at standstill, rotating or excited. A prerequisite is, however, that the 20 Hz generator must be supplied with a DC voltage or an external ac voltage source depending on the application, (see the connection diagrams in *P34x/EN/IN*).

Ensure that the cell [0F0D: **COMMISSIONING TESTS**, **Test Mode**] is set to **Contacts Blocked**. This blocks the operation of the Trip Contacts. Check the Out of Service LED is on and the alarm message 'Prot'n Disabled' is given.

The following measurements are available in the **Measurements 3** column. All measurements are based on the 20 Hz components extracted from the voltage and current signals. A magnitude threshold level of 0.05 V and 0.1mA for the voltage and current is implemented, below which the associated measurements display zero. The 64S R is the compensated resistance in both primary and secondary quantities. The resistance measurement displays a significantly large number to indicate an invalid measurement if either the voltage or the current magnitude is below the threshold. The 64S Voltage signal is used as the phase reference for the 64S current signal.

MEASUREMENTS 3
64S V Magnitude
64S I Magnitude
64S I Angle
64S R secondary
64S R primary

The purpose of the 64S calibration procedure is to establish the correct settings for the angle compensation (**64S Angle Comp**), the Series Resistance (**64S Series R**) and the parallel conductance (**64S Parallel G**). They are required so that the relay can calculate more accurately the value of the fault resistance Rf based on the equivalent circuit as shown below.

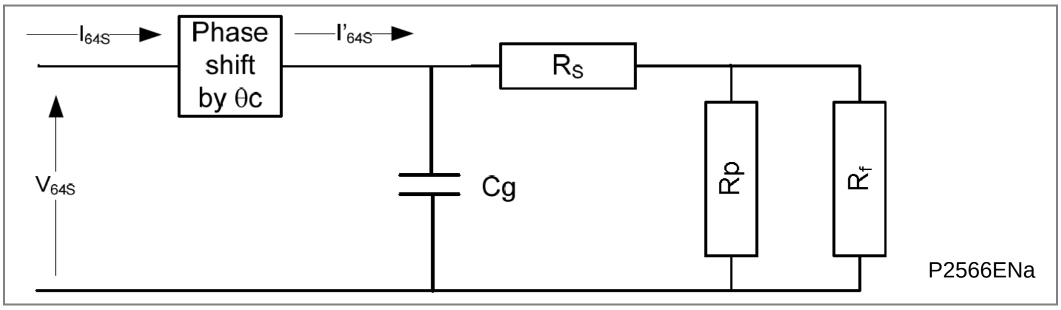

Figure 14 - Calibration model for the 64S

To obtain the correct results, it is essential that the '64S R Factor' should have already been established and has been entered into the relay. The '64S Angle Comp', '64S Series R' and '64S Parallel G' settings should all be set to 0 initially.

As the calibration procedure requires fault resistance to be applied to the star point of the generator which is on the primary circuit, it is better to proceed with the calibration based on primary settings and measurements. Therefore in the Configuration column, the

Setting Values should be set to **Primary**. For the **64S R** measurement, the primary value should also be used.

Caution	**Dangerous high voltages may be present at the generator terminals if the 20 Hz injection voltage is not removed when the generator is taken out of service.**

If the 20 Hz injection voltage generator receives power from the generator terminal voltage, then the 20 Hz injection voltage generator will be automatically switched off whenever the generator terminal voltage is not present.

6.4.7.5.1 Angle Compensation Setting (64S Angle Comp)

The angle compensation setting is used to remove any phase error caused by the internal and external CTs associated with the 64S current measurement. To establish this setting, it is necessary to remove any parallel earthing point such as an additional earthing transformer which may contribute to the presence of the parallel resistance Rp in Figure 4.

Under no fault condition, the relay should only see the lumped capacitance Cg on the system. The I64S should be capacitive and should lead the voltage V64S by +90°. The **64S Angle Comp** setting should be adjusted so that the +90° is achieved. The measurement **64S I Angle** displays the angle of I’64S with respect to V64S and can be used to assist with this setting adjustment.

6.4.7.5.2 Series Resistance Setting (64S Series R)

After the angle compensation setting has been set, the series resistance RS can be established by applying a short circuit fault at the generator star point. With the **64S Series R** setting originally set to zero, the relay is now measuring the resistance due to the earthing transformer and its connecting cables.

In order to compensate for this extra resistance of the circuit, the value read from the **64S R Primary** measurement should be entered into the **64S Series R** setting. After the setting has been entered, the **64S R Primary** measurement should now read zero.

6.4.7.5.3 Calibration at the 64S Alarm and Trip Settings

The above calibration procedures are performed under no fault and short-circuit fault conditions. To provide a better match of the relays **64S R Primary** measurement to the applied fault resistance across the whole range of fault resistance it may be necessary to re-adjust the **64S Angle Comp** setting and **64 Series R** setting at the **64S R<1 Alm Set** and **64S R<2Trip Set** points.

Apply a fault resistance equal to the **64S R<2 Trip** setting and adjust the **64S Angle Comp** and the **64S Series R** settings for a closer match to the relays measured resistance **64S R Primary** if required. Repeat the process with a fault resistance equal to the **64S R<1 Alarm** setting.

In general it is recommended that the **64S Series R** setting should only be used to provide minor adjustments of a few ohms and is more appropriate for trip or alarm threshold of less than a few hundred ohms. To provide a closer match of the relays **64S R Primary** measurement to the applied fault resistance at higher settings it is more effective to adjust the **64S Angle Comp** setting.

Since the resistance measured by the relay is effectively equal to $\frac{V_{64S}}{I_{64S} * \cos(\theta_{I'64S-V64S})}$, if the measured resistance is less than expected, the **64S Angle Comp** setting should be adjusted such that the current vector will be rotated in the anti-clockwise direction. If the **64S Angle Comp** (θc) was originally set as a negative value (that is, the current vector was rotated clockwise by |θc|°), it should be set less negative so that the I64S*cos($\theta_{I'64S-V64S}$) denominator decreases in value. The reverse logic should be applied if the measured resistance is more than expected.

Finally apply various fault resistances, re-check the short-circuit condition and the no fault condition to ensure that the results are satisfactory. This whole process may need to be re-iterated to ensure the most desirable match.

6.4.7.5.4 Parallel Conductance (64S Parallel G)

After the above settings have been finalized, re-connect any parallel earthing point of the system, then apply a no fault condition to the generator. The **64S R Primary** measured by the relay will be the parallel resistance Rp. It's reciprocal should then be applied to the **64S Parallel G** setting.

6.4.7.5.5 Checking with other Resistance Values

After the above calibration procedure, apply different fault resistance to the star point of the generator so as to obtain a complete set of measurements from the relay.

6.4.7.5.6 Testing the 100% stator earth fault protection on the generator

Insert on the primary side a resistance which corresponds to about 90 % of the resistance for the alarm stage, **64S R<1 Alm Set** and check that the **64S R<1 Alarm** is operated after the delay time **64S R<1 Alm Dly** (default setting 1.00s). Further reduce the earth resistance to 90 % of the trip stage pickup value **64S R<2 Trip Set** and check that the **64S R<2 Trip** is operated after the delay time, **64S R<2 Trip Dly** (default setting 1.00 sec). Also, if used check that the **64S I>1 Trip** is operated after the delay time, **64S I>1 Trip Dly** (default setting 1.00 sec). Reset all alarms.

Remove the test resistor.

If the 100% stator earth fault protection is blocked with the DDBs 64S I>1 Inhibit (552) or 64S R<1 Inhibit (553) or 64S R<2 Inhibit (554) using an opto-isolated input, the functioning of the input should be checked.

Switch off the voltage supply for the 20 Hz generator, or energize the block binary input. Check the yellow alarm led turns on and check 'Alarms/Faults Present - 64S Fail Alarm' is on the display (assuming the 64S Fail Alarm (DDB 383) is connected to the 64S Fail signal (DDB 1298) in the PSL). Switch on the 20 Hz generator or remove the block and reset all alarms.

If this alarm indication already occurs with the 20 Hz generator in operation, the monitoring threshold, **64S V<1 Set**, should be reduced. This can be the case if the loading resistance is very small (< 1 Ω).

Note	*If the external band pass filter accessory is to be checked as well, short-circuit the earthing or neutral transformer on the secondary side with the machine at standing still, and switch the 20 Hz generator on. Multiply the operational measured value* ***64S I Magnitude*** *with the CT ratio of the miniature CT (such as 400 A/ 5A). The flowing current must be greater than 3 A. If the current is significantly less, the resonance frequency of the bandpass has changed. It can be better matched by adding or removing capacitors. Finally, remove the shorting link and check the galvanic isolation with the measured value* ***64S V Magnitude****.*

6.4.7.6 Start-Up Tests

Ensure that the cell [0F0D: **COMMISSIONING TESTS**, **Test Mode**] is set to **Contacts Blocked**. This blocks the operation of the Trip Contacts. Check the Out of Service LED is on and the alarm message 'Prot'n Disabled' is given.

The 20 Hz generator and bandpass filter accessories of the protection device must be operational.

Start up the generator and excite it to maximum generator voltage.

Check the protection does not pick up.

Check that the resistance values, **64S R< primary/secondary**, in the **Measurements 3** menu are well in excess of the trip and alarm settings, **64S R<1 Alm Set/64S R<2 Trip Set** and the current value, **64S I Magnitude**, is at least half the overcurrent setting, **64S I>1 Trip Set**.

Shut down generator.

If the 100% stator earth fault protection operates during the generator start up there may be some zero sequence voltage being produced by the machine, depending on the type of starting, which could be superimposed on the 20 Hz voltage causing incorrect measurements. The P345 100% stator earth fault protection includes a low pass filter and a bandpass filter which will filter signal frequencies 0-15 Hz and >25 Hz. DDB 1297 **64S F Band Block** operates between 15-25 Hz and can be used in the PSL to block the 100% stator earth fault protection via the inhibit signals, DDBs 552 - 64S I> Inhibit, DDB 553 - 64S R<1 Inhibit, DDB 554 - 64S R<2 Inhibit.

Ensure that the cell [0F0D: **COMMISSIONING TESTS**, **Test Mode**] is set to **Disabled**. Check the Out of Service LED is off and the alarm message 'Prot'n Disabled' is reset.

On completion of the tests any protection elements that were disabled for testing purposes must have their original settings restored in the **CONFIGURATION** column.

6.4.8 P391 Generator Rotor Earth Fault Protection

Warning	**The user shall be familiar with all safety statements listed in this chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

Warning	**Before connecting the P391 to compatible equipment, all applicable safety statements and warnings for the relevant equipment shall be considered, to minimize the likelihood of any safety hazards.**

Caution	**Isolate all voltage inputs, including the high voltage DC rotor winding supply before removing the P391 from its mounting, removing its front panel or transparent terminal cover.**

Caution	**The internal circuitry of the P391 is not protected against electrostatic discharges (ESD) when the front panel is removed. ESD precautions and a clean working environment should be maintained when setting the internal frequency jumper PL3.**
Caution	**See section 2 of the Installation Chapter, *P34x/EN IN*, ‘Handling of Electronic Equipment’ for information on electrostatic discharge precautions.**

Caution	**Under no circumstances should the high voltage DC rotor winding supply be connected directly to the P391 500 Ω internal calibration resistors (terminals A3, A5, B3 or B5).**

Caution	**Before connecting temporary test equipment or test circuits, all applicable ratings, safety statements and warnings for the relevant equipment shall be considered, to minimize the likelihood of any safety hazards.**

Caution	**Isolate all voltage inputs, including the high voltage DC rotor winding supply from all equipment before connecting or disconnecting test equipment or test circuits.**
Caution	**Ensure that test circuits will not cause an electric shock, burns, fire or explosion hazard during setup or testing.**

Caution	**Before energizing the P391 voltage inputs, ensure the unit is suitably mounted and mechanically secure and its front panel and transparent terminal cover are fitted.**
Caution	**The P391 front panel and transparent terminal cover shall remain in place at all times during operation of the unit.**

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.**

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.**

The P391 provides generator Rotor Earth Fault (REF) protection using an integral coupling, injection and measurement circuit to monitor the rotor field winding for the presence of earth faults.

The P391 injects a square wave signal into the rotor field winding circuit and measures any change to the waveform characteristic caused by a change in resistance between the rotor winding circuit and earth (a rotor earth fault).

Continuous measurements are passed to the P342/P343/P344/P345 protection relay for processing via a Current Loop Input/Output (CLIO) signaling circuit with an output range of 0-20 mA. The P391 CLIO output signal can be connected to any of the four CLIO inputs provided by the P342/P343/P344/P345 range.

Note	*Rotor earth fault protection is only available if the protection relay includes the CLIO hardware option.*

The square wave frequency can be adjusted to 0.25 Hz, 0.5 Hz, or 1.0 Hz, selectable by a jumper link on the P391 unit.

Note	*The **Injection Freq** setting in the P342/P343/P344/P345 **ROTOR EF** menu must also be adjusted to match the injection frequency setting of the P391.*

All P342/P343/P344/P345 protection elements except rotor earth fault protection should be disabled during rotor earth fault tests, to avoid spurious operation. These can be disabled in the P342/P343/P344/P345 **CONFIGURATION** column. It is advisable to note any elements temporarily disabled so they can be re-enabled after testing.

6.4.8.1 Injection Frequency Selection

Caution **The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

The P391 injects a square-wave voltage at a fixed injection frequency (Fg) into the generator field winding. A jumper link on the P391 unit (see section 11 in *P34x/EN IN*) is used to select the frequency 0.25 Hz or 0.5 Hz or 1 Hz. To change the injection frequency the P391 should be de-energized first before the front panel is removed to reveal the jumper link. The default factory position is 0.25 Hz.

Note *The **Injection Freq** setting in the **ROTOR EF** menu in the P34x must be set to match the injection frequency link setting in the P391.*

The injection frequency can be selected after measuring the rotor field winding capacitance to earth. Table 30 provides recommendations for the injection frequency based on the capacitance measurement. If the operating time is important to the application, follow the guideline below to select the frequency for the injection signal. Otherwise, leave the module at its default jumper setting of 0.25 Hz.

The rotor capacitance can be measured with a capacitance meter by connecting the meter across the field winding to earth. The P391 should be disconnected from the rotor field winding. Measurement should be taken from the P391 cable ends shorted together (cables connected to A16-B16) and earth (cable connected to C6) to include the capacitance of any cables between the rotor field winding and the P391. The machine should be off line and the field excitation should be off during the capacitance measurement. The field breaker should be closed for the capacitance measurement.

Alternatively, apply a known resistance to the slip rings and earth as described in section 6.4.8.7 ‘Testing the rotor earth fault protection on the generator at standstill’. Then with the highest injection frequency set in the P391 and P345, 1 Hz, measure the insulation resistance. The measured resistance value **64R Fault** in the P34x **Measurements 3** menu indicates the rotor earth resistance. Then select the next highest injection frequency of 0.5 Hz and measure the insulation resistance. If the measured insulation resistances are the same, choose 1 Hz as the injection frequency. Otherwise select the lowest injection frequency of 0.25 Hz and measure the insulation resistance. If the measured insulation resistances at 0.5 Hz and 0.25 Hz are the same, choose 0.5 Hz as the injection frequency. Otherwise choose 0.25 Hz as the injection frequency.

Note *If there is no insulation deterioration, there is no leakage path via the field winding to earth and the insulation resistance value is extremely high. The relay provides capped values if the fault resistance measurement is beyond the supported range: 50 ohms to 1M ohms.*

Field-to-Earth Capacitance (Cfg)	Jumper position	Injection signal frequency (Fg)	Time between each insulation resistance calculation	Calculation accuracy
Cfg <2.1 μF	Bottom	1 Hz	0.5 s	Within Specification
2.1 μF≤ Cfg ≤5 μF	Middle	0.5 Hz	1 s	Within Specification
5 μF≤ Cfg ≤10 μF	Top	0.25 Hz	2 s	Within Specification
Cfg >10 μF	Top	0.25 Hz	2 s	Not Within Specification

Table 30 - Injection frequency for different field to earth capacitance values

Forced Rfault value	Forced or capped value	Value meaning
9.999 MΩ	Capped	Infinity value (divide by zero prevented).
9.998 MΩ	Forced	CLIO input data invalid
9.997 MΩ	Forced	Rotor EF protection disabled.

Forced Rfault value	Forced or capped value	Value meaning
9.996 MΩ	Capped	R fault above upper limit (1 MΩ)
0 Ω	Capped	R fault below lower limit (50 Ω).

Table 31 - Forced/capped resistance values

6.4.8.2 Calibration

Caution	The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.

Disconnect the rotor field winding and brush earth connection from the P391.

Connect the P342/P343/P344/P345 and P391 to the 500 Ω calibration resistance (P391 terminals A3-A5 or B3-B5) as shown in Figure 5.

Check the measured resistance value **64R Fault** in the **Measurements 3** menu in the P34x relay. If the resistance measurement is not equal to 500 Ω use the **R Compensation** setting in the **ROTOR EF** menu to compensate the measurement until it is as close as possible to 500 Ω. The **R Compensation** value should be chosen so that the average value is nearest 500 Ω if the measurement is fluctuating between two values.

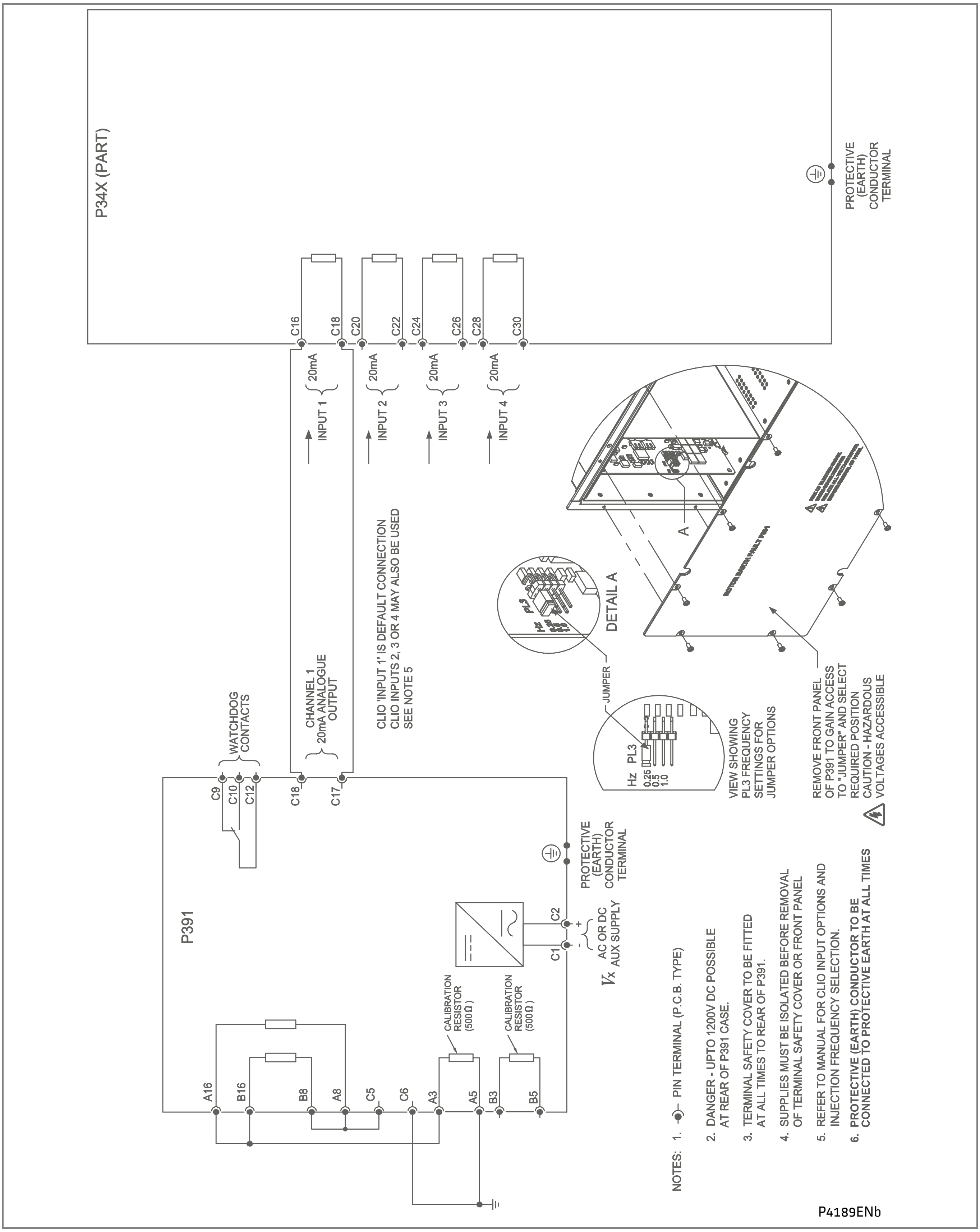

Figure 15 - Calibration circuit for the 64R rotor earth fault protection

6.4.8.3 Connect the Test Circuit

Caution	**The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

Determine which output relay has been selected to operate when a 64R R<2 Trip (DDB 780) and 64R R<1 Alarm (DDB 394) occurs by viewing the relay's PSL.

The PSL can only be changed using the appropriate software. If this software is not available then the default output relay allocations will still be applicable.

If the 64R protection signals are not independently mapped directly to an output relay in the PSL, output relay 3 and 4 could be used in the default PSL to check the operation of the protection functions. In the default PSL relay 3 is the designated protection trip contact and 64R R<2 Trip (DDB 780) is assigned to this contact. In the default PSL relay 4 is the designated general alarm contact and 64R R<1 Alarm (DDB 394) is assigned to this contact. Note, in the default PSL relay 3 is set to operate the Any Trip signal (DDB 674) which initiates the trip LED.

The associated terminal numbers can be found from the external connection diagrams in chapter *P34x/EN IN*.

Connect the output relays so that its operation will trip the test set and stop the timer.

Connect the P342/P343/P344/P345 and P391 to a resistance decade box or discrete resistance to represent to fault resistance and a capacitor to represent the field winding capacitance as shown in Figure 16.

To simulate a generator standstill condition no signal should be injected into the 3-phase voltage and current inputs.

Ensure that the timer will start when the current and voltage is applied to the relay.

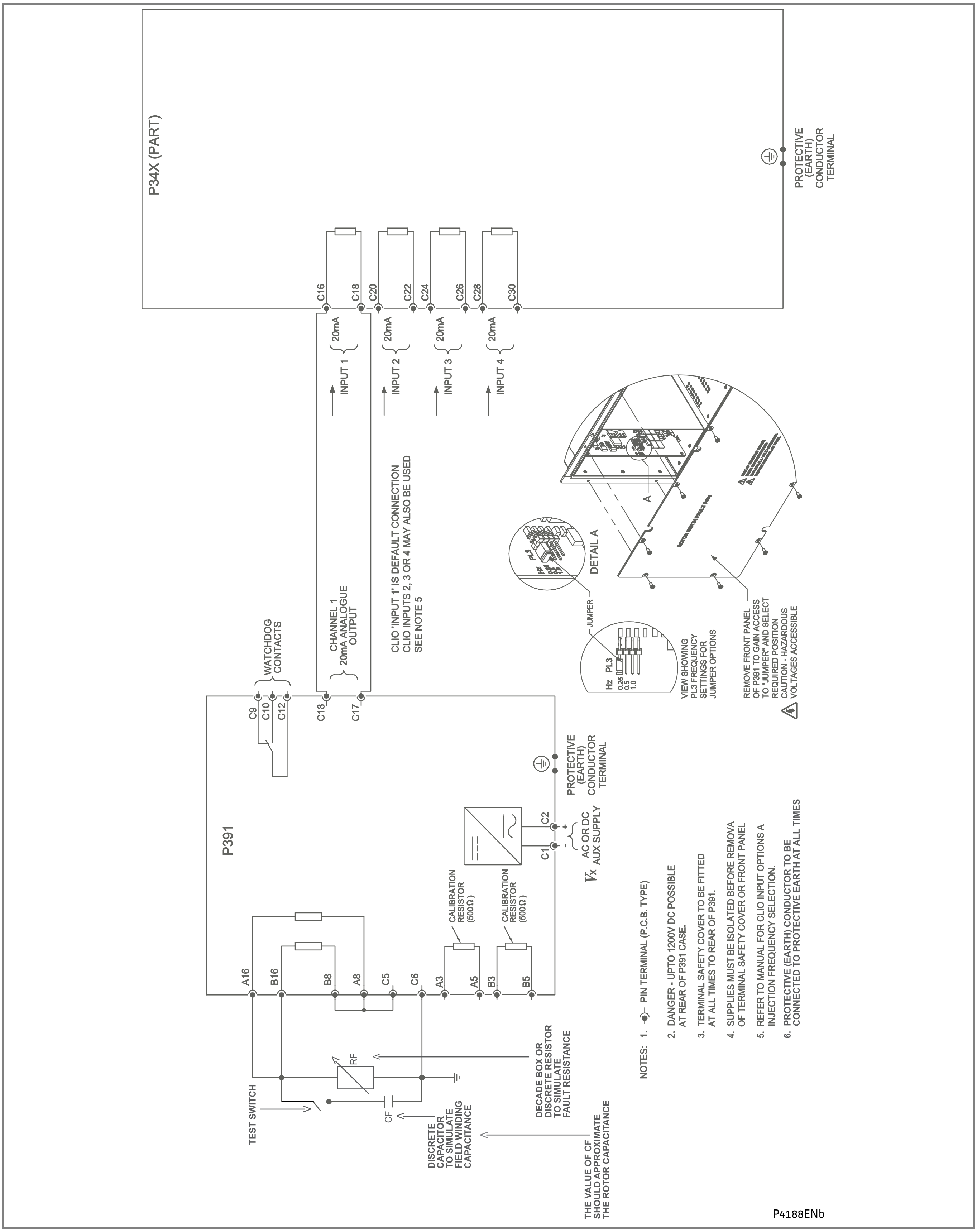

Figure 16 - Test circuit for the 64R rotor earth fault protection

6.4.8.4 Check the Pick-Up Settings

Caution	**The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

Ensure that the following settings [**GROUP 1 ROTOR EF**, **Injection Freq, CL I/P Select**, **R Compensation** are set to the application values]

If two LEDs have been assigned to give the 64R alarm and trip start information, 64R R<2 Start (DDB 1023) and 64R Start R<1 Alm (DDB 1022), these may be used to indicate correct operation or alternatively the time delayed alarm and trip signals 64R R<2 Trip (DDB 780) and 64S R<1 Alarm Trip (DDB 394) can be used. If not, monitor options will need to be used - see the next paragraph.

Go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F05: **Monitor Bit 1**] to 1023, [0F06: **Monitor Bit 2**] to 1022. Cell [0F04: **Test Port Status**] will now appropriately set or reset the bits that now represent 64R R<2 Start (DDB 1023) and 64R Start R<1 Alm (DDB 1022). From now on you should monitor the indication of [0F04: Test Port Status].

Set 64S R<2 Trip = **Enabled** and **64R R<1 Alarm** = **Disabled.**

Set the fault resistance to 10% above the trip setting and slowly reduce the resistance until the 64R R<2 start element operates (Bit 1 of [0F04: **Test Port Status**] is set to 1).

Check that the resistance corresponds to the **64R R<2 Trip Set**, ±10% (1 k to 10 kΩ), ±5% (10 k to 80 kΩ). Note, the time the relay takes to update the resistance measurements will depend on the injection frequency, see Table 30.

Switch OFF the test and reset the alarms.

Set **64S R<1 Alarm** = **Enabled** and **64R R<2 Trip** = **Disabled**.

Set the fault resistance to 10% above the alarm setting and slowly reduce the resistance until the 64R R<1 start element operates (Bit 2 of [0F04: **Test Port Status**] is set to 1).

Check that the resistance corresponds to the **64R R<1 Alm Set**, ±10% (1 k to 10 kΩ), ±5% (10 k to 80 kΩ).

Switch OFF the test and reset the alarms.

Note	*The measured rotor resistance value **64R Fault** is shown in the **Measurements 3** menu.*

6.4.8.5 Checking with other Resistance Values

Caution	**The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

If required, after the above test procedure, apply different fault resistances so as to obtain a complete set of measurements from the relay. Use the **64R Fault** values in the **Measurements 3** menu to check the rotor earth resistance accuracy.

6.4.8.6 Perform the Timing Tests

Caution	**The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

Ensure that the timer is reset.

Set 64S R<2 Trip = **Enabled and 64S R<1 Alarm** = **Disabled**.

Apply a resistance of half the setting in cell [3918: **GROUP 1 ROTOR EF, 64R R<2 Trip Set**] to the relay and note the time displayed when the timer stops.

Check the red trip LED and yellow alarm LED turns on when the relay operates. Check 'Alarms/Faults Present - 64R Start R<2, 64R Trip R<2' is on the display. Reset all alarms.

Note	*In the default PSL relay 3 is set to operate the Any Trip signal (DDB 674) which initiates the trip LED.*

Check that the operating time recorded by the timer is within the range, 64S R<2 Trip Dly setting ±2% or 2.5/fs whichever is greater, fs = injection frequency.

Allowance must also be made for the accuracy of the test equipment being used.

Ensure that the timer is reset.

Set **64R R<2 Trip** = **Disabled** and **64R R<1 Alarm** = **Enabled**.

Apply a resistance to give half the setting in cell [390C: **GROUP 1 ROTOR EF**, **64R R<1 Alm Set**] to the relay and note the time displayed when the timer stops.

Check the yellow alarm LED turns on when the relay operates. Check 'Alarms/Faults Present - 64R Alarm R<1' is on the display. Reset all alarms.

Check that the operating time recorded by the timer is within the range, **64R R<1 Alm Dly** setting ±2% or 2.5/fs whichever is greater.

Allowance must also be made for the accuracy of the test equipment being used.

Ensure that the timer is reset.

6.4.8.7 Testing the Rotor Earth Fault Protection on the Generator at Standstill

Caution	**The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

The rotor earth fault protection can be checked with the machine at standstill. For this the P345 and P391 coupling unit must be connected to the rotor circuit as shown in the Installation Chapter, *P34x/EN IN*.

In the **Commission Tests** menu set the **Test Mode** setting to **Test Mode** which takes the relay out of service and blocks the 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. The Test Mode menu cell is used to allow secondary injection testing to be performed on the relay without operation of the trip contacts.

First set the injection frequency setting as described in section 6.4.8.1.

Check the measured rotor to ground resistance value in fault free condition. The measured rotor resistance value should be very large, for example 9.996 MΩ. The measured rotor resistance value **64R Fault** is shown in the **Measurements 3** menu.

After this fault resistors equal to the **64R R<1 Alm Set** and the **64R R< Trip Set** settings are installed, and the resistance measurements **64R Fault** are checked against the resistor values. In machines with rotating rectifier excitation, the resistor is placed between the measurement slip rings. In machines with excitation via slip rings the resistor is placed between one slip ring and earth.

Finally, the alarm and the trip stages are checked. A test resistance is applied equal to 90 % of the set value and operation of the alarm and trip stage is checked. On machines with slipring excitation, the test is performed for both sliprings.

To check operation of the alarm and trip stages go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F05: **Monitor Bit 1**] to 780, [0F06: **Monitor Bit 2**] to 394. Cell [0F04: **Test Port Status**] will now appropriately set or reset the bits that now represent 64R R<2 Trip (DDB 780) and 64R R<1 Alm (DDB 394).

Remove the earth fault resistor and check the resistance measurement is similar to the value measured previously for a fault free condition.

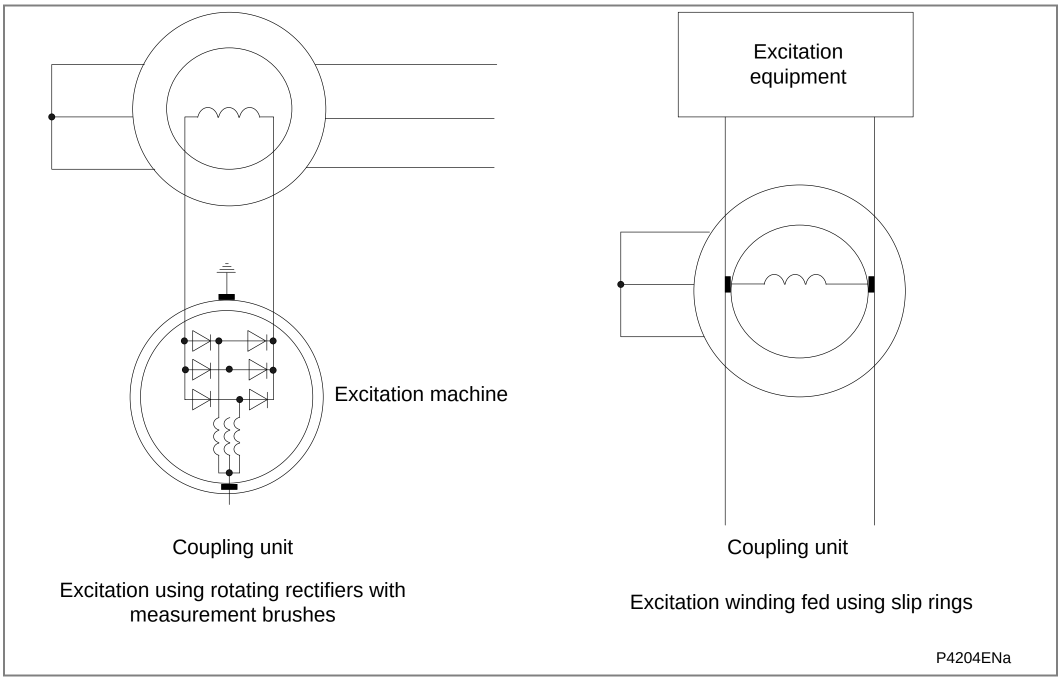

Figure 17 - Types of excitation

6.4.8.8 Testing the Rotor Earth Fault Protection on the Generator when Running

Caution	**The user shall be familiar with all safety statements listed in section 6.4.8 of this Commissioning chapter and the Safety Information section/Safety Guide *SFTY/4LM/G11* (or later issue) before undertaking any work on the P391.**

To eliminate interference which might originate from a running machine, in particular from the excitation system, it is recommended to perform an additional check with the machine running.

Caution	**If the rotor circuit is not isolated from earth, insertion of the test resistor to earth can result in a double earth fault. Non observance of the following procedures could result in fatal injury or equipment damage. Ensure that the rotor circuit is completely isolated from earth, to avoid the test earthing resistor from causing a double earth fault.**

Start up the generator and excite to the rated voltage. If applicable place measurement brushes into operation. In fault free condition the measured rotor resistance value should be very large, for example 9.996 MΩ. The measured rotor resistance value **64R Fault** is shown in the **Measurements 3** menu. Shut down generator.

In machines with rotating rectifier excitation, the resistor is placed between the measurement slip rings. In machines with excitation via slip rings the resistor is placed between one slip.

Set the resistor to approximately 90% of the trip resistance **64R R<2 Trip Set**. Start up the generator and excite to the rated voltage. Check the measured resistance value **64R Fault** in the **Measurements 3** menu and check the 64R R<2 Trip (DDB 780) has operated. Shut down generator. For generators with excitation via slip rings, the test is repeated for the other slip ring.

Set the resistor to 90% of the alarm resistance **64R R<2 Alm Set**. Start up the generator and excite to the rated voltage. Check the measured resistance value **64R Fault** in the **Measurements 3** menu and check the 64R R<2 Alm (DDB394) has operated. Shut down generator. For generators with excitation via slip rings, the test is repeated for the other slip ring.

Remove the earth fault resistor. Start up the generator and excite to the rated voltage and check the resistance measurement is similar to the value measured previously for a fault free condition. Shut down generator.

To check operation of the alarm and trip stages go to the **COMMISSION TESTS** column in the menu, scroll down and change cells [0F05: **Monitor Bit 1**] to 780, [0F06: **Monitor Bit 2**] to 394. Cell [0F04: **Test Port Status**] will now appropriately set or reset the bits that now represent 64R R<2 Trip (DDB 780) and 64R R<1 Alm (DDB 394).

In the **Commission Tests** Menu set the **Test Mode** setting to **Disabled** which puts the relay back into service. Check yellow 'Out of Service' and 'Alarm' LED and alarm message 'Prot'n. Disabled' are reset.

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 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.

Voltage	Cell in MEASUREMENTS 1 Column (02)	Corresponding VT ratio (in VT and CT RATIO column (0A) of menu)
V_{AB}	[0214: VAB Magnitude]	[0A01: Main VT Primary] [0A02: Main VT Sec’y]
V_{BC}	[0216: VBC Magnitude]	
V_{CA}	[0218: VCA Magnitude]	
V_{AN}	[021A: VAN Magnitude]	
V_{BN}	[021C: VBN Magnitude]	
V_{CN}	[021E: VCN Magnitude]	
V_{N}	[0220: VN Measured Mag]	[0A05: VN VT Primary] [0A06: VN VT Sec’y]
V_{N2} (P344/P345 only)	[0250: VN2 Measured Mag]	[0A03: VN2 VT Primary] [0A04: VN2 VT Sec’y]
C/S Voltage (P345 only)	[0270: MEASUREMENTS 1, C/S Voltage Mag] (P345 only)	[0A16: C/S VT Prim'y] [0A17: C/S VT Sec'y]

Table 32 - Measured voltages and VT ratio settings

7.2 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.*

For P243, P34x and P64x, check that the IA/IB/IC Differential currents measured on the relay are less than 10% of the IA/IB/IC Bias currents, see the **MEASUREMENTS 3** menu. Check that the I2 Magnitude negative phase sequence current measured by the relay is not greater than expected for the particular installation, see the **MEASUREMENTS 1** menu. Check that the active and reactive power measured by the relay are correct, see the Measurements 2 menu. The power measurement modes are described in the *Measurements and Recording* chapter.

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 P741/P742/P743/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% (1% for the P34x, 5% for the P741/P742/P743/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.*

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] and [0F12: COMMISSION TESTS, Static Test] are set to '**Disabled**' (0F0D (not 0F0F) for P14x/P24x/P34x/P341/P44y/P54x/P841).

For P14x, P34x, P341, P44x, P44y, P445, P54x, P547 OR P841, 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/P841A, P44y or P54x, xxxx = 0606 for P24x/P34x/P341, xxxx = 0608 for P44x, 0619 for P841B).

If the menu language was changed to allow accurate testing, it must now be restored to the customer's preferred language.

If a MiCOM P991 or Easergy test block is installed, remove the MiCOM P992 or Easergy test plug and replace the test block 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.

Notes:

TEST AND SETTING RECORDS

CHAPTER 12

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

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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 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

Relay type	MiCOM P…………
Model number	
Serial number	
Rated current In	
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.

Overcurrent test set	Model: Serial No:	
Injection test set	Model: Serial No:	
Phase angle meter	Model: Serial No:	
Phase rotation meter	Model: Serial No:	
Optical power meter	Model: Serial No:	
Insulation tester	Model: Serial No:	
Setting software:	Type: Version:	

1.5 Checklist

	Have all relevant safety instructions been followed?	Yes ☐ No ☐

5. PRODUCT CHECKS

5.1 With the relay de-energized

5.1.1	Visual inspection	
	Relay damaged?	Yes ☐ No ☐
	Rating information correct for installation?	Yes ☐ No ☐
	Case earth installed?	Yes ☐ No ☐
5.1.2	Current transformer shorting contacts close?	Yes ☐ No ☐ Not checked ☐
5.1.3	Insulation resistance >100 MΩ at 500 V dc	Yes ☐ No ☐ Not tested ☐
5.1.4	External wiring	
	Wiring checked against diagram?	Yes ☐ No ☐
	Test block connections checked?	Yes ☐ No ☐ N/A ☐
5.1.5	Watchdog contacts (auxiliary supply off)	
	Terminals 11 and 12 Contact closed?	Yes ☐ No ☐
	Contact resistance	Ω Not measured ☐
	Terminals 13 and 14 Contact open?	Yes ☐ 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 ☐ No ☐
	Terminals 13 and 14 Contact closed?	Yes ☐ No ☐
	Contact resistance	Ω Not measured ☐
5.2.2	LCD front panel display	
	LCD contrast setting used	
5.2.3	Date and time	
	Clock set to local time?	Yes ☐ No ☐
	Time maintained when auxiliary supply removed?	Yes ☐ No ☐
5.2.4	Light emitting diodes	
	Relay healthy (green) LED working?	Yes ☐ No ☐
	Alarm (yellow) LED working?	Yes ☐ No ☐
	Out of service (yellow) LED working?	Yes ☐ No ☐
	Trip (red) LED working?	Yes ☐ No ☐
	All programmable LEDs working? (may be 8 or 18 depending on the model)	Yes ☐ No ☐
5.2.5	Field supply voltage	
	Value measured between terminals 7 and 9	V dc
	Value measured between terminals 8 and 10	V dc

5.2.6 Input opto-isolators (numbers vary depending on the product)

Opto input 1	working?	Yes	☐	No	☐		
Opto input 2	working?	Yes	☐	No	☐		
Opto input 3	working?	Yes	☐	No	☐		
Opto input 4	working?	Yes	☐	No	☐		
Opto input 5	working?	Yes	☐	No	☐		
Opto input 6	working?	Yes	☐	No	☐		
Opto input 7	working?	Yes	☐	No	☐		
Opto input 8	working?	Yes	☐	No	☐		
Opto input 9	working?	Yes	☐	No	☐	N/A	☐
Opto input 10	working?	Yes	☐	No	☐	N/A	☐
Opto input 11	working?	Yes	☐	No	☐	N/A	☐
Opto input 12	working?	Yes	☐	No	☐	N/A	☐
Opto input 13	working?	Yes	☐	No	☐	N/A	☐
Opto input 14	working?	Yes	☐	No	☐	N/A	☐
Opto input 15	working?	Yes	☐	No	☐	N/A	☐
Opto input 16	working?	Yes	☐	No	☐	N/A	☐
Opto input 17	working?	Yes	☐	No	☐	N/A	☐
Opto input 18	working?	Yes	☐	No	☐	N/A	☐
Opto input 19	working?	Yes	☐	No	☐	N/A	☐
Opto input 20	working?	Yes	☐	No	☐	N/A	☐
Opto input 21	working?	Yes	☐	No	☐	N/A	☐
Opto input 22	working?	Yes	☐	No	☐	N/A	☐
Opto input 23	working?	Yes	☐	No	☐	N/A	☐
Opto input 24	working?	Yes	☐	No	☐	N/A	☐
Opto input 25	working?	Yes	☐	No	☐	N/A	☐
Opto input 26	working?	Yes	☐	No	☐	N/A	☐
Opto input 27	working?	Yes	☐	No	☐	N/A	☐
Opto input 28	working?	Yes	☐	No	☐	N/A	☐
Opto input 29	working?	Yes	☐	No	☐	N/A	☐
Opto input 30	working?	Yes	☐	No	☐	N/A	☐
Opto input 31	working?	Yes	☐	No	☐	N/A	☐
Opto input 32	working?	Yes	☐	No	☐	N/A	☐

5.2.7 Output relays

Relay 1	working?		Yes ☐	No	☐		
	Contact resistance		Ω ☐	Not measured	☐		
Relay 2	working?		Yes ☐	No	☐		
	Contact resistance		Ω ☐	Not measured	☐		
Relay 3	working?		Yes ☐	No	☐		
	Contact resistance		Ω ☐	Not measured	☐		
Relay 4	working?		Yes ☐	No	☐		
	Contact resistance	(N/C)	Ω ☐	Not measured	☐		
		(N/O)	Ω ☐	Not measured	☐		
Relay 5	working?		Yes ☐	No	☐		
	Contact resistance	(N/C)	Ω ☐	Not measured	☐		
		(N/O)	Ω ☐	Not measured	☐		
Relay 6	working?		Yes ☐	No	☐		
	Contact resistance	(N/C)	Ω ☐	Not measured	☐		
		(N/O)	Ω ☐	Not measured	☐		
Relay 7	working?		Yes ☐	No	☐		
	Contact resistance	(N/C)	Ω ☐	Not measured	☐		
		(N/O)	Ω ☐	Not measured	☐		
Relay 8	working?		Yes ☐	No	☐	N/A	☐
	Contact resistance	(N/C)	Ω ☐	Not measured	☐		
		(N/O)	Ω ☐	Not measured	☐		

Relay 9	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 10	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 11	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐
Relay 12	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐
Relay 13	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐
Relay 14	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐
Relay 15	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐
Relay 16	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐

Relay 17	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 18	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 19	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 20	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 21	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 22	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 23	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐
Relay 24	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐

Relay 25	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 26	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 27	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 28	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 29	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 30	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance		Ω ☐ Not measured ☐
Relay 31	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐
Relay 32	working?		Yes ☐ No ☐ N/A ☐
	Contact resistance	(N/C)	Ω ☐ Not measured ☐
		(N/O)	Ω ☐ Not measured ☐

5.2.8	RTD inputs		
	Resistor tolerance		
	RTD 1 reading	[0412: RTD 1 Label]	%
	RTD 2 reading	[0413: RTD 2 Label]	°C
	RTD 3 reading	[0414: RTD 3 Label]	°C
	RTD 4 reading	[0415: RTD 4 Label]	°C
	RTD 5 reading	[0416: RTD 5 Label]	°C
	RTD 6 reading	[0417: RTD 6 Label]	°C
	RTD 7 reading	[0418: RTD 7 Label]	°C
	RTD 8 reading	[0419: RTD 8 Label]	°C
	RTD 9 reading	[041A: RTD 9 Label]	°C
	RTD 10 reading	[041B: RTD 10 Label]	°C

5.2.9	Current loop inputs	
	CLI input type	0-1mA ☐ 0-10mA ☐ 0-20mA ☐ 4-20mA ☐
	CLI1 reading at 50% CLI maximum range [0425: CLI1 Input Label]	
	CLI2 reading at 50% CLI maximum range [0426: CLI2 Input Label]	
	CLI3 reading at 50% CLI maximum range [0427: CLI3 Input Label]	
	CLI4 reading at 50% CLI maximum range [0428: CLI4 Input Label]	

5.2.10	Current loop outputs	0-1mA ☐ 0-10mA ☐ 0-20mA ☐ 4-20mA ☐
	CLO output type	mA
	CLO1 output current at 50% of rated output	mA
	CLO2 output current at 50% of rated output	mA
	CLO3 output current at 50% of rated output	mA
	CLO4 output current at 50% of rated output	mA

5.2.11	First rear communications port	
	Communication standard	K-Bus ☐ MODBUS ☐ IEC60870-5-103 ☐ IEC61850 ☐ DNP3* ☐
	Communications established?	Yes ☐ No ☐
	Protocol converter tested?	Yes ☐ No ☐ N/A ☐

5.2.12	Second rear communications port	K-Bus ☐ EIA(RS)485 ☐ EIA(RS)232 ☐
	Communication port configuration	Yes ☐ No ☐
	Communications established?	Yes ☐ No ☐
	Protocol converter tested?	Yes ☐ No ☐ N/A ☐

5.2.13	Current inputs		
	Displayed current		Primary ☐ Secondary ☐
	Phase CT ratio	$\left(\frac{\text{[Phase CT Primary]}}{\text{[Phase CT Sec'y]}}\right)$	N/A ☐
	Earth fault CT ratio	$\left(\frac{\text{[E/F CT Primary]}}{\text{[E/F CT Sec'y]}}\right)$	N/A ☐
	SEF CT ratio	$\left(\frac{\text{[SEF CT Primary]}}{\text{[SEF CT Sec'y]}}\right)$	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
IA (2)	A N/A	A N/A
IB (2)	A N/A	A N/A
IC (2)	A N/A	A N/A

5.2.14 Voltage inputs

Displayed voltage		Primary Secondary
Main VT ratio	$\left(\frac{\text{[Main VT Primary]}}{\text{[Main VT Sec'y.]}}\right)$	N/A
VN VT ratio	$\left(\frac{\text{[VN VT Primary]}}{\text{[VN VT Secondary]}}\right)$	N/A
VN2 VT ratio	$\left(\frac{\text{[VN2 VT Primary]}}{\text{[VN2 VT Secondary]}}\right)$	N/A
C/S VT ratio	$\left(\left[\frac{C/S\ VT\ prim'y}{C/S\ VT\ Sec'y}\right]\right)$	N/A

Input VT	Applied Value	Displayed value
Va	V	V
Vb	V	V
Vc	V	V
VN	V	V
VN2 (P344/P345 only)	V	V
C/S Voltage (P345 only)	V	V

6. SETTING CHECKS

6.1	Application-specific function settings applied?	Yes No
	Application-specific PSL settings applied?	Yes No N/A
6.2	Application-specific function settings verified?	Yes No N/A
	Application-specific PSL tested?	Yes No N/A

6.3 Demonstrate correct relay operation

6.3.1 Generator differential protection (P343/P344/P345)

6.3.1.2	Generator Differential lower slope pickup	A
6.3.1.3	Generator Differential upper slope pickup	A
6.3.2.1	Generator Differential Phase A contact routing OK?	Yes No
	Generator Differential Phase A trip time	s
6.3.2.2	Generator Differential Phase B contact routing OK?	Yes No
	Generator Differential Phase B trip time	s
6.3.2.3	Generator Differential Phase C contact routing OK?	Yes No
	Generator Differential Phase C trip time	s
	Average trip time, Phases A, B and C	s

6.4 Generator-Transformer differential protection (P343/P344/P345)

6.4.1.1	Low set element current sensitivity (Is1)	HV IA	A	HV IB	A	HV IC	A
		LV IA	A	LV IB	A	LV IC	A
6.4.1.2	Low set element operating time	HV IA	s	HV IB	s	HV IC	s
6.4.1.3	High set element current sensitivity (Is HS1)	HV IA	A	HV IB	A	HV IC	A
6.4.1.4	High set element operating time	HV IA	s	HV IB	s	HV IC	s

6.4.2	Differential through stability by primary injection OK?	Yes ☐ No ☐
6.4.3	CT secondary wiring differential through stability test by secondary injection OK?	Yes ☐ No ☐

6.4.4 Low set element bias characteristic

In (amps)	Is1 (pu)	0%				K1 = 30%				K2 = 80%			
		Trip		No trip		Trip		No trip		Trip		No trip	
		I1	I2	I1	I2	I1	I2	I1	I2	I1	I2	I1	I2
1	0.2												
5	0.2												

6.4.5	Second-harmonic blocking	A
6.4.6	Fifth-harmonic blocking	A

6.4.7 Generator 100% stator earth fault protection via low frequency injection (P345)

6.4.7.2 Check pickup settings

64S I> Trip tested?	Yes ☐ No ☐
64S I>1 Trip pickup	A
64S R<2 Trip tested?	Yes ☐ No ☐
64S R<2 Trip pickup	Ohms
64S R<1 Alarm tested?	Yes ☐ No ☐
64S R<1 Alarm pickup	Ohms

6.4.7.3 Perform timing tests

64S I>1 Trip timing tested?	Yes ☐ No ☐
Applied current	A
Expected operating time	s
Measured operating time	s
64S R<2 Trip timing tested?	Yes ☐ No ☐
Applied impedance	Ohms
Expected operating time	s
Measured operating time	s
64S R<1 Alarm timing tested?	Yes ☐ No ☐
Applied impedance	Ohms
Expected operating time	s
Measured operating time	s

6.4.7.4 Perform the 100% stator earth fault supervision test

64S Supervision tested?	Yes ☐ No ☐
Applied voltage	V
Applied current	A
Expected operating time	s
Measured operating time	s

6.4.7.5 Calibration Tests
Establish the 64S angle compensation, series resistance and parallel conductance settings

6.4.7.5.1	64S Angle Comp	°
6.4.7.5.2	64S Series R	Ohms

6.4.7.5.3	Calibration at the 64S alarm and trip settings	
	Primary resistance check of 64S R<2 Trip tested?	Yes ☐ No ☐
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	64S Angle Comp	°
	64S Series R	Ohms
	Primary resistance check of 64S R<1 Alarm tested?	Yes ☐ No ☐
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	64S Angle Comp	°
	64S Series R	Ohms
6.4.7.5.4	64S Parallel G	S
6.4.7.5.5	Check with other resistance values	
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
6.4.7.6	Testing the 100% stator earth fault protection on the generator	
	Primary resistance check of 64S R<1 Alarm tested?	Yes ☐ No ☐
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	Expected operating time	s
	Measured operating time	s
	Primary resistance check of 64S R<2 Trip tested?	Yes ☐ No ☐
	Applied primary resistance	Ohms
	64S R Primary measurement	Ohms
	Expected operating time	s
	Measured operating time	s
	Primary resistance check of 64S I>1 Trip tested?	Yes ☐ No ☐
	Applied primary resistance	Ohms
	64S I Magnitude measurement	A
	Expected operating time	s
	Measured operating time	s
	Supervision function tested?	Yes ☐ No ☐
	Primary resistance measurements checked?	Yes ☐ No ☐
6.4.7.7	Start-up Tests	
	Start-up test performed?	Yes ☐ No ☐
	64S R Primary measurement	Ohms
6.4.8	Generator rotor earth fault protection	
6.4.8.1	Select injection frequency	
	Applied injection frequency	Hz
6.4.8.2	Calibration	
	R Compensation	Ohms

6.4.8.4	Check pickup settings	
	64R R<2 Trip tested?	Yes ☐ No ☐
	64R R<2 Trip pickup	Ohms
	64R R<1 Alarm tested?	Yes ☐ No ☐
	64R R<1 Alarm pickup	Ohms
6.4.8.5	Check with other resistance values	
	Applied primary resistance	Ohms
	64R R Fault measurement	Ohms
	Applied primary resistance	Ohms
	64R R Fault measurement	Ohms
	Applied primary resistance	Ohms
	64R R Fault measurement	Ohms
	Applied primary resistance	Ohms
	64R R Fault measurement	Ohms
	Applied primary resistance	Ohms
	64R R Fault measurement	Ohms
6.4.8.6	Perform timing tests	
	64R R<2 Trip timing tested?	Yes ☐ No ☐
	Applied resistance	Ohms
	Expected operating time	s
	Measured operating time	s
	64R R<1 Alarm timing tested?	Yes ☐ No ☐
	Applied resistance	Ohms
	Expected operating time	s
	Measured operating time	s
6.4.8.7	Testing the rotor earth fault protection on the generator at standstill	
	Resistance check with no fault?	Yes ☐ No ☐
	64R R Fault measurement	Ohms
	Resistance check of 64S R<1 Alarm tested?	Yes ☐ No ☐
	Applied resistance	Ohms
	64R R Fault measurement	Ohms
	Resistance check of 64S R<2 Trip tested?	Yes ☐ No ☐
	Applied resistance	Ohms
	64R R Fault measurement	Ohms
	Operation check of 64S R<1 Alarm tested?	Yes ☐ No ☐
	Operation check of 64S R<1 Alarm tested?	Yes ☐ No ☐
6.4.8.8	Testing the rotor earth fault protection on the generator running	
	Resistance check with no fault?	Yes ☐ No ☐
	64R R Fault measurement	Ohms
	Operation check of 64S R<2 Trip tested?	Yes ☐ No ☐
	Operation check of 64S R<1 Alarm tested?	Yes ☐ No ☐
	Resistance check with no fault?	Yes ☐ No ☐
	64R R Fault measurement	Ohms
7.	**ON-LOAD CHECKS**	
	Test wiring removed?	Yes ☐ No ☐ N/A ☐
	Disturbed customer wiring re-checked?	Yes ☐ No ☐ N/A ☐
	On-load test performed?	Yes ☐ No ☐
7.1	VT wiring checked?	Yes ☐ No ☐ N/A ☐
	Phase rotation correct?	Yes ☐ No ☐
	Displayed voltage	Primary ☐ Secondary ☐

Main VT ratio	$\left(\frac{\text{[Main VT Primary]}}{\text{[Main VT Sec'y.]}}\right)$	V N/A ☐
VN VT ratio	$\left(\frac{\text{[VN VT Primary]}}{\text{[VN VT Secondary]}}\right)$	V N/A ☐
VN2 VT ratio	$\left(\frac{\text{[VN2 VT Primary]}}{\text{[VN2 VT Secondary]}}\right)$	V N/A ☐
C/S VT ratio	$\left(\left[\frac{C/S\ VT\ prim'y}{C/S\ VT\ Sec'y}\right]\right)$	V N/A ☐

Voltages	Applied Value	Displayed value
VAN/VAB	V	V
VBN/VBC	V	V
VCN/VCA	V	V
VN	V	V
VN2 (P344/P345 only)	V	V
C/S (P345 only)	V	V

7.2

CT wiring checked?		Yes ☐ No ☐ N/A ☐
CT polarities correct?		Yes ☐ No ☐
Displayed current		Primary ☐ Secondary ☐
Phase CT ratio	$\left(\frac{\text{[Phase CT Primary]}}{\text{[Phase CT Sec'y]}}\right)$	A N/A ☐
Earth Fault CT ratio	$\left(\frac{\text{[E/F CT Primary]}}{\text{[E/F CT Sec'y]}}\right)$	A N/A ☐
SEF CT ratio	$\left(\frac{\text{[SEF CT Primary]}}{\text{[SEF CT Sec'y]}}\right)$	A N/A ☐

Currents	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
IA (2)	A N/A ☐	A N/A ☐
IB (2)	A N/A ☐	A N/A ☐
IC (2)	A N/A ☐	A N/A ☐

8. FINAL CHECKS

Test wiring removed?	Yes ☐	No ☐	N/A ☐
Disturbed customer wiring re-checked?	Yes ☐	No ☐	N/A ☐
Test mode disabled?	Yes ☐	No ☐	
Circuit breaker operations counter reset?	Yes ☐	No ☐	N/A ☐
Current counters reset?	Yes ☐	No ☐	N/A ☐
Event records reset?	Yes ☐	No ☐	
Fault records reset?	Yes ☐	No ☐	
Disturbance records reset?	Yes ☐	No ☐	
Alarms reset?	Yes ☐	No ☐	
LEDs reset?	Yes ☐	No ☐	
Secondary front cover replaced?	Yes ☐	No ☐	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 Easergy Studio (MiCOM S1 Studio) software lets you read/write 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 the Studio software. A summary is given in Send Settings to a MiCOM Px40 Device below.

The Easergy Studio (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 Easergy Studio (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.

Notes:

MAINTENANCE

CHAPTER 13

Date:	09/2016	
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:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 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) P44x (P441, P442 & P444): 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2)	P54x (P543, P544, P545 & P546): 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) P547: 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P74x (P741, P742 & P743): 10P740xx (xx = 01 to 07) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)

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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-supervising 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, you should be familiar with the contents of the Safety Information chapter/Safety Guide SFTY/5L M/L11 or later issue, the Technical Data chapter and the ratings on the equipment 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, you should be familiar with the contents of the Safety Information chapter/Safety Guide SFTY/5L M/L11 or later issue, the Technical Data chapter and the ratings on the equipment 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 Pozidriv or PZ1 screws. The P24x/P34x/P64x ranges 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 at least 30 seconds 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, you should be familiar with the contents of the Safety Information chapter/Safety Guide SFTY/5L M/L11 or later issue, the Technical Data chapter and the ratings on the equipment 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 14

Date:	09/2016	
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:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 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) P44x(P442 & P444): 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2)	P54x (P543, P544, P545 & P546): 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) P547: 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P74x (P741, P742 & P743): 10P740xx (xx = 01 to 07) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)

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TABLES

Notes:

1 INTRODUCTION

Warning	**Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information chapter/Safety Guide SFTY/5L M/L11 or later issue, the Technical Data chapter and the ratings on the equipment 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 the following table 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	Power-Up Errors section
Relay powers up - but indicates error and halts during power-up sequence	Error Message/Code On Power-Up section
Relay Powers up but Out of Service LED is illuminated	Out of Service LED illuminated on Power Up section
Error during normal operation	Error Code During Operation section
Mal-operation of the relay during testing	Mal-Operation of the Relay during Testing section

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: 0c140005/0c0d0000 0c140006/0c0e0000 Last 4 digits provide details on the actual error.	These messages indicate that a problem has been detected on the main processor board of the relay (located in the front panel). Input Module (inc. Opto-isolated inputs) Output Relay Cards 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 Contact Blocked. Otherwise proceed to test 2.	If the setting is Contact Blocked 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 Contact Blocked or that the protection has been disabled due to a hardware verify error (see the *Out of service LED illuminated* table..
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:

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 15

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

CONTENTS

FIGURES

TABLES

1 INTRODUCTION

This chapter describes the remote interfaces of the MiCOM relay in enough detail to allow integration in a substation communication network. The relay supports a choice of one of a number of protocols through the rear 2-wire EIA(RS)485 communication interface, selected using the model number when ordering. This is in addition to the front serial interface and second rear communications port, which supports the Courier protocol only. According to the protocol and hardware options selected, the interface may alternatively be presented over an optical fiber interface, or via an Ethernet connection.

The supported protocols include:

- Courier
- IEC-60870-5-103
- DNP3.0
- MODBUS
- IEC 61850 Ethernet Interface

Note	*The IEC 60870-5-103 standard may be abbreviated to IEC870-5-103, IEC 60870, or even -103. In some references, it may even be described as the 'VDEW' standard.*

The implementation of both Courier and IEC 60870-5-103 on RP1 can also, optionally, be presented over fiber as well as EIA(RS)485.

The DNP3.0 implementation is available via the EIA(RS)485 port.

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.

Note	*The second rear Courier port and the fiber optic interface are mutually exclusive as they occupy the same physical slot.*

An outline of the connection details for each of the communications ports is provided here. The ports are configurable using settings - a description of the configuration follows the connections part. Details of the protocol characteristics are also shown.

For each of the protocol options, the supported functions and commands are listed with the database definition. The operation of standard procedures such as extraction of event, fault and disturbance records, or setting changes is also described.

The descriptions in this chapter do not aim to fully describe the protocol in detail. Refer to the relevant documentation protocol for this information. This chapter describes the specific implementation of the protocol in the relay.

2 CONNECTIONS TO THE COMMUNICATION PORTS

2.1 Front Port

The front communications port is not intended for permanent connection. The front communications port supports the Courier protocol and is implemented on an EIA(RS)232 connection. A 9-pin connector type, as described in the ‘Getting Started’ (GS) chapter of this manual, is used, and the cabling requirements are detailed in the ‘Connection Diagrams’ (CD) chapter of this manual.

2.2 Rear Communication Port EIA(RS)485

If the IEC60870-5-103, or the DNP3.0 protocols are specified as the interface for the rear port, then connections conform entirely to the EIA(RS)485 standards outline below. If, however, the Courier protocol is specified as the rear port protocol, the interface can be set either to EIA(RS)485 or K-Bus. The configuration of the port as either EIA(RS)485 or K-Bus is described later together with K-Bus details, but as connection to the port is affected by this choice, you should note these points:

- Connection to an EIA(RS)485 device is polarity sensitive, whereas K-Bus connection is not. In all other respects (bus wiring, topology, connection, biasing, and termination) K-Bus can be considered the same as EIA(RS)485.
- Whilst connection to or between an EIA(RS)485 port and an EIA(RS)232 port on a PC can be implemented using a general purpose EIA(RS)485 to EIA(RS)232 converter. However, connection between an EIA(RS)232 port and K-Bus requires a KITZ101, KITZ102 or KITZ201.

The protocol provided by the relay is indicated in the relay menu in the **Communications** column. Using the keypad and LCD, first 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 that is being used by the rear port.

Note	*Unless the K-Bus option is chosen for the rear port, correct polarity must be observed for the signal connections. In all other respects (bus wiring, topology, connection, biasing and termination) K-Bus can be considered the same as EIA(RS)485.*

2.3 Second Rear Communications Port (Courier)

Relays with Courier, MODBUS, IEC60870-5-103 or DNP3.0 protocol on the first rear communications port have the option of a second rear port, running the Courier language. The second port is intended typically for dial-up modem access by protection engineers or operators, when the main port is reserved for SCADA communication traffic. Communication is through 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 using MiCOM S1 Studio.

When changing the port configuration between K-Bus, EIA(RS)-485 and EIA(RS)-232, reboot the relay to update the hardware configuration of the second rear port.

The EIA(RS)-485 and EIA(RS)-232 protocols can be configured to operate with a modem, using an IEC60870 10-bit frame.

If both rear communications ports are connected to the same bus, make sure their address settings are not the same to avoid message conflicts.

Port Configuration	Valid Communication Protocol
K-Bus	K-Bus
EIA(RS)-232	IEC60870 FT1.2, 11-bit frame IEC60870, 10-bit frame
EIA(RS)-485	IEC60870 FT1.2, 11-bit frame IEC60870, 10-bit frame

Table 1 - Second rear comm. port communication protocol

2.3.1 Courier Protocol

The second rear communications port is functionally the same as described in the previous section for a Courier rear communications port, with the following exceptions:

2.3.2 Event Extraction

Automatic event extraction is not supported when the first rear port protocol is Courier, MODBUS or CS103. It is supported when the first rear port protocol is DNP3.0.

2.3.3 Disturbance Record Extraction

Automatic disturbance record extraction is not supported when the first rear port protocol is Courier, MODBUS or CS103. It is supported when the first rear port protocol is DNP3.0.

2.3.4 Connection to the Second Rear Port

The second rear Courier port connects using the 9-way female D-type connector (SK4) in the middle of the card end plate (between the IRIG-B connector and lower D-type). The connection complies with EIA(RS)-574.

For IEC60870-5-2 over EIA(RS)-232			For K-bus or IEC60870-5-2 over EIA(RS)-485	
Pin	Connection		Pin*	Connection
1	No Connection			
2	RxD			
3	TxD			
4	DTR#		4	EIA(RS)-485 - 1 (+ ve)
5	Ground			
6	No Connection			
7	RTS#		7	EIA(RS)-485 - 2 (- ve)
8	CTS#			
9	No Connection			
# - These pins are control lines for use with a modem.			* - All other pins unconnected.	

Notes *Connector pins 4 and 7 are used by both the EIA(RS)-232and EIA(RS)-485 physical layers, but for different purposes. Therefore, the cables should be removed during configuration switches.*
When using the EIA(RS)-485 protocol, an EIA(RS)-485 to EIA(RS)-232 converter is needed to connect the relay to a modem or PC running MiCOM S1 Studio. 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 using a KITZ101 or 102.

Table 2 - Pin connections over EIA(RS)-232 and EIS(RS)-485

2.4 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 while the product's connection diagrams show the polarization of the connection terminals, 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, make sure the two-wire connection is not reversed.

EIA(RS)-485 provides the capability to connect multiple devices to the same two-wire bus. MODBUS is a master-slave protocol, so one device is the master, and the remaining devices are slaves. It is not possible to connect two masters to the same bus, unless they negotiate bus access.

2.4.1 Bus Termination

The EIA(RS)-485 bus must have 120 Ω (Ohm) ½ Watt terminating resistors fitted at either end across the signal wires, see the *EIA(RS)-485 bus connection arrangements* diagram below. Some devices may be able to provide the bus terminating resistors by different connection or configuration arrangements, in which case separate external components are not needed. However, this product does not provide such a facility, so if it is located at the bus terminus, an external termination resistor is needed.

2.4.2 Bus Connections and Topologies

The EIA(RS)-485 standard requires each device to 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 depends on the application, although a multi-strand 0.5 mm^2 per core is normally adequate. Total cable length must not exceed 1000 m. The screen must be continuous and connected 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 the bus cable has a signal ground connection, it must be ignored. However, the signal ground must have continuity for the benefit of other devices connected to the bus. For both safety and noise reasons, the signal ground must never be connected to the cable's screen or to the product's chassis.

2.4.3 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 switch 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 are weakly pulled to a defined voltage level of about 1 V. 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 is injected. Some devices may (optionally) be able to provide the bus bias, in which case external components are not required.

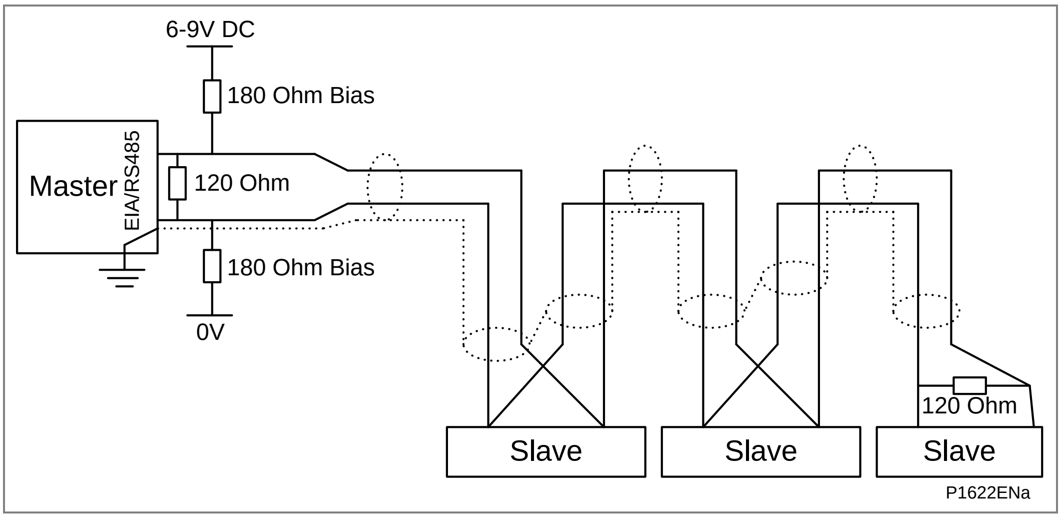


Figure 1 - EIA(RS)485 bus connection arrangements

It is possible to use the product's field voltage output (48 V DC) to bias the bus using values of 2.2 k Ω (½W) as bias resistors instead of the 180 Ω resistors shown in the *EIA(RS)-485 bus connection arrangements* diagram. Note these warnings apply:

Warnings	**It is extremely important that the 120 Ω termination resistors are fitted. Otherwise the bias voltage may be excessive and may damage the devices connected to the bus.** **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.** **Ensure the field voltage is not used for other purposes, such as powering logic inputs, because noise may be passed to the communication network.**

2.4.4 Courier Communication

Courier is the communication language developed to allow remote interrogation of its range of protection relays. Courier uses a master and slave. EIA(RS)-232 on the front panel allows only one slave but EIA(RS)-485 on the back panel allows up to 32 daisy-chained slaves. Each slave unit has a database of information and responds with information from its database when requested by the 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. MiCOM S1 Studio is compatible is specifically designed for setting changes with the relay.

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 needed. This unit (and information on how to use it) is available from Schneider Electric. A typical connection arrangement is shown in the *K-bus remote communication connection arrangements* diagram below. 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 1000 m in length and have up to 32 relays connected to it.

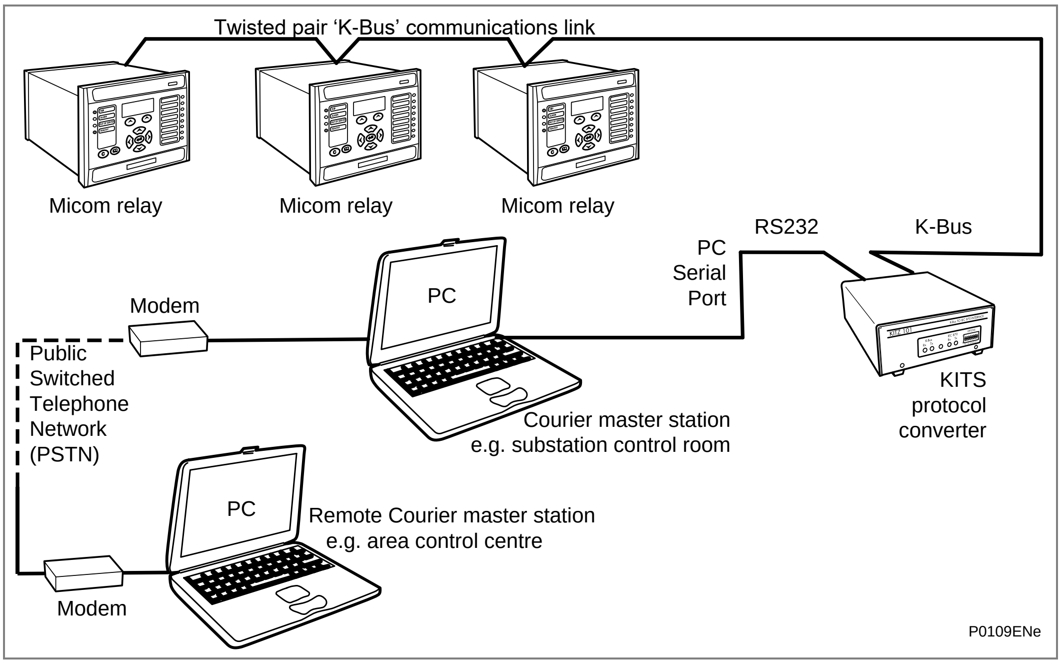


Figure 2 - Remote communication connection arrangements

Once the physical connection is made to the relay, configure the relay's communication settings using the keypad and LCD user interface.

1. In the relay menu, select the **Configuration** column, then check that the **Comms. settings** cell is set to **Visible**.
2. Select the **Communications** column. Only two settings apply to the rear port using Courier, the relay's address and the inactivity timer. Synchronous communication uses a fixed baud rate of 64 kbits/s.
3. Move down the **Communications** column from the column heading to the first cell down. This shows the communication protocol.

```
RP1 Protocol
Courier
```

4. The next cell down the column controls the address of the relay. As up to 32 relays can be connected to one K-Bus spur, each relay must have a unique address so messages from the master control station are accepted by one relay only. Courier uses an integer (from 0 to 254) for the relay address that is set with this cell. Important: no two relays should have the same Courier address. The master station uses the Courier address to communicate with the relay.

```
RP1 Address
1
```

5. The next cell down controls the inactivity timer.

```
RP1 Inactiv timer
10.00 mins.
```

The inactivity timer controls how long the relay waits 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.*

The next cell down controls the physical media used for the communication.

```
RP1 Physical link
Copper
```

The default setting is to select the electrical (copper) connection. If the optional fiber optic interface is fitted to the relay, then this setting can be changed to '**Fiber optic**'. This cell is invisible if a second rear communications port or an Ethernet card is fitted, as they are mutually exclusive and occupy the same physical location.

6. If the Physical link selection is copper, the next cell down becomes visible to further define the configuration:

```
RP1 Port Config
KBus
```

The setting choice is between K-Bus and EIA(RS)485. Selecting K-Bus allows connection with K-series devices, but means that a KITZ converter must be used to make a connection. If the EIA(RS)485 selection is made, direct connections can be made to proprietary equipment such as MODEMs. If the EIA(RS)485 selection is made, then two further cells become visible to control the frame format and the communication speed:

7. The frame format is selected in the RP1 Comms mode setting:

```
RP1 Comms Mode
IEC60870 FT1.2
```

The standard default is the IEC 60870-FT1.2. This is an 11-bit framing. Alternatively, a 10-bit framing may be selected for use with MODEMs that do not support 11-bit framing.

8. The final RP1 cell controls the communication speed or baud rate:

```
RP1 Baud Rate
19200 bits/s
```

Courier communications is asynchronous and three baud rate selections are available to allow the relay communication rate to be matched to that of the connected equipment. Three baud rates are supported by the relay, '9600 bits/s', '19200 bits/s' and '38400 bits/s'.

Important	**If you modify protection and disturbance recorder settings using an on-line editor such as PAS&T, you must confirm them. To do this, from the Configuration column select the Save changes cell. Off-line editors such as MiCOM S1 Studio do not need this action for the setting changes to take effect.**

2.4.5 MODBUS Communication

Important	**MODBUS is not available for all MiCOM products. MODBUS availability is shown in the *Supported Protocols* table.**

MODBUS is a master/slave communication protocol that can be used for network control. In a similar way to Courier, the master device initiates all actions and the slave devices (the relays) respond to the master by supplying the requested data or by taking the requested action. MODBUS communication uses a twisted pair connection to the rear port and can be used over a distance of 1000 m with up to 32 slave devices.

To use the rear port with MODBUS communication, configure the relay's communication settings using the keypad and LCD user interface.

1. In the relay menu, select the **Configuration** column, then check that the **Comms. settings** cell is set to **Visible**.
2. Select the **Communications** column. Four settings apply to the rear port using MODBUS that are described below.
3. Move down the **Communications** column from the column heading to the first cell down. This shows the communication protocol.

```
RP1 Protocol
MODBUS
```

4. The next cell down controls the MODBUS address of the relay. 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.

```
RP1 MODBUS address
23
```

5. The next cell down controls the inactivity timer.

```
RP1 Inactiv timer
10.00 mins.
```

The inactivity timer controls how long the relay waits 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.

6. The next cell down the column controls the baud rate to be used:

```
RP1 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.

7. The next cell controls the parity format used in the data frames:

```
RP1 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 physical media used for the communication.

```
RP1 Physical link
Copper
```

The default setting is to select the electrical (copper) connection. If the optional fiber optic interface is fitted to the relay, then this setting can be changed to '**Fiber optic**'. This cell is invisible if a second rear communications port or an Ethernet card is fitted, as they are mutually exclusive and occupy the same physical location.

8. The next cell down controls the format of the Date/Time (software 30 or later):

```
MODBUS
IEC time standard
```

The format can be selected as either **Standard** (as for IEC60870-5-4 'Binary Time 2a') which is the default, or to **Reverse** for compatibility with MICOM Px20 and Px30 product ranges. For more information see the *Date and Time Format* section.

2.4.6 IEC 60870-5 CS 103 Communication

The IEC specification IEC 60870-5-103: Telecontrol Equipment and Systems, Part 5: Transmission Protocols Section 103 defines the use of standards IEC 60870-5-1 to IEC 60870-5-5 to perform communication with protection equipment. The standard configuration for the IEC 60870-5-103 protocol is to use a twisted pair connection over distances up to 1000 m. As an option for IEC 60870-5-103, the rear port can be specified to use a fiber optic connection for direct connection to a master station. The relay operates as a slave in the system, responding to commands from a master station. The method of communication uses standardized messages which are based on the VDEW communication protocol.

To use the rear port with IEC 60870-5-103 communication, configure the relay's communication settings using the keypad and LCD user interface.

1. In the relay menu, select the **Configuration** column, then check that the **Comms. settings** cell is set to **Visible**.
2. Select the **Communications** column. Four settings apply to the rear port using IEC 60870-5-103 that are described below.

   Move down the 'COMMUNICATIONS' column from the column heading to the first cell to confirm the communication protocol:

```
RP1 Protocol
IEC60870-5-103
```

3. The next cell sets the address of the relay on the IEC 60870-5-103 network:

```
RP1 Address
162
```

Up to 32 relays can be connected to one IEC 60870-5-103 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. IEC 60870-5-103 uses an integer number between 0 and 254 for the relay address. It is important that no two relays have the same address. The address is then used by the master station to communicate with the relay.

4. The next cell down the column controls the baud rate to be used:

```
RP1 Baud rate
9600 bits/s
```

IEC 60870-5-103 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 IEC 60870-5-103 master station.

5. The next cell down controls the period between IEC 60870-5-103 measurements:

```
RP1 Meas period
30.00 s
```

The IEC 60870-5-103 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.

6. An optional fiber optic card is available in the relay to allow optical connection to the IEC 60870-5-103 communication to be made over an optical connection. When fitted, it converts between EIA(RS)485 signals and fiber optic signals and the following cell is visible in the menu column:

```
RP1 Physical link
Copper
```

The default setting is to select the electrical (copper) connection. If the optional fiber optic interface is fitted to the relay, then this setting can be changed to ‘Fiber optic’. This cell is invisible if a second rear communications port or an Ethernet card is fitted, as they are mutually exclusive and occupy the same physical location.

7. The following cell which may be displayed, is not currently used but is available for future expansion.

```
RP1 InactivTimer
```

8. The next cell down can be used for monitor or command blocking:

```
RP1 CS103Blocking
```

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 are ignored, such as CB Trip/Close or change setting group. When in this mode the relay returns a **negative acknowledgement of command** message to the master station.

2.4.7 DNP3.0 Communication

The DNP3.0 protocol is defined and administered by the DNP User Group. Information about the user group, DNP3.0 in general and protocol specifications can be found on their website: www.dnp.org

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 is achieved using a twisted pair connection to the rear port and can be used over a distance of 1000 m with up to 32 slave devices.

1. To use the rear port with DNP3.0 communication, configure the relay's communication settings using the keypad and LCD user interface.
1. In the relay menu, select the **Configuration** column, then check that the **Comms. setting** cell in is set to **Visible**.
2. Four settings apply to the rear port using IEC 60870-5-10. These are described below.
3. Move down the **Communications** column from the column heading to the first cell down. This shows the communications protocol.

```
RP1 Protocol
DNP3.0
```

4. The next cell controls the DNP3.0 address of the relay:

```
RP1 Address
232
```

Up to 32 relays can be connected to one DNP3.0 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. DNP3.0 uses a decimal number between 1 and 65519 for the relay address. It is important that no two relays have the same DNP3.0 address. The DNP3.0 address is then used by the master station to communicate with the relay.

5. The next cell down the column controls the baud rate to be used:

```
RP1 Baud rate
9600 bits/s
```

DNP3.0 communication is asynchronous. Six baud rates are supported by the relay '1200 bits/s', '2400 bits/s', '4800 bits/s', '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 DNP3.0 master station.

6. The next cell down the column controls the parity format used in the data frames:

```
RP1 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 DNP3.0 master station.

7. The next cell down the column controls the physical media used for the communication:

```
RP1 Physical link
Copper
```

The default setting is to select the copper 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 second rear comms. port is fitted as it is mutually exclusive with the fiber optic connectors.

8. The next cell down the column sets the time synchronization request from the master by the relay:

```
RP1 Time sync.
Enabled
```

The time sync. can be set to either enabled or disabled. If enabled it allows the DNP3.0 master to synchronize the time.

2.5 Second Rear Communication Port

For relays having the second rear (Courier) communications port fitted, the settings are located immediately below the ones for the first port described above. The second rear communications port only supports the Courier protocol and the settings are similar to those for Courier RP1. The first cell displays:

1. Move down the settings until the following sub heading is displayed.

```
Rear Port 2
(RP2)
```

2. The next cell defines the protocol, which is fixed at Courier for RP2.

```
RP2 protocol
Courier
```

3. The following cell indicates the status of the hardware.

```
RP2 card status
EIA(RS)232 OK
```

4. The following cell allows for selection of the port configuration.

```
RP2 port config.
EIA(RS)232
```

5. The port can be configured for EIA(RS)232, EIA(RS)485 or K-Bus.
As in the case of the first rear Courier port, if K-Bus is not selected certain other cells to control the communication mode and speed become visible. If either EIA(RS)232 or EIA(RS)485 is selected for the port configuration, the next cell is visible and selects the communication mode.

```
RP2 comms.  Mode
IEC60870 FT1.2
```

6. The standard default is the IEC 60870 FT1.2 for normal operation with 11-bit modems. Alternatively, a 10-bit framing with no parity bit can be selected for special cases.

7. The next cell down sets the communications port address.

```
RP2 address
255
```

Since up to 32 devices can be connected to one K-bus spur, it is necessary for each device to have a unique address so that messages from the master control station are accepted by one device only. Courier uses an integer number between 0 and 254 for the device address that is set with this cell. It is important that no two devices have the same Courier address. The Courier address is then used by the master station to communicate with the device. The default value is 255 and must be changed to a value in the range 0 to 254 before use.

8. The following cell controls the inactivity timer.

```
RP2 InactivTimer
15 mins.
```

9. 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. This includes revoking any password access that was enabled. The inactivity timer can be set between 1 and 30 minutes.
10. If either EIA(RS)232 or EIA(RS)485 is selected for the port configuration, the following cell is visible and selects the communication speed (baud rate):

```
RP2 baud rate
19200
```

Courier communications is asynchronous and three selections are available to allow the relay communication rate to be matched to that of the connected equipment. The three baud rates supported by the relay are: ‘9600 bits/s’, ‘19200 bits/s’ and ‘38400 bits/s’.

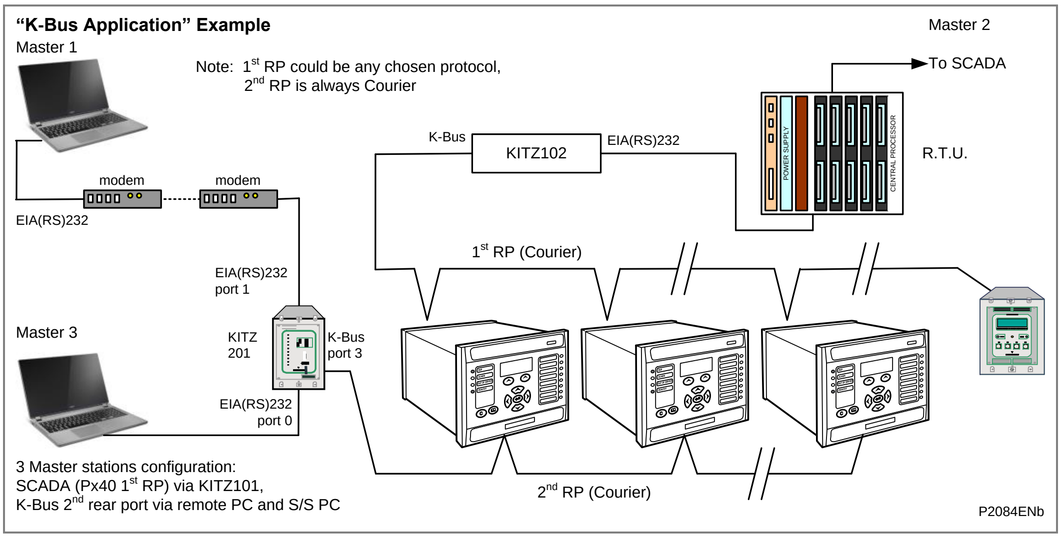


Figure 3 - Second rear port K-Bus application

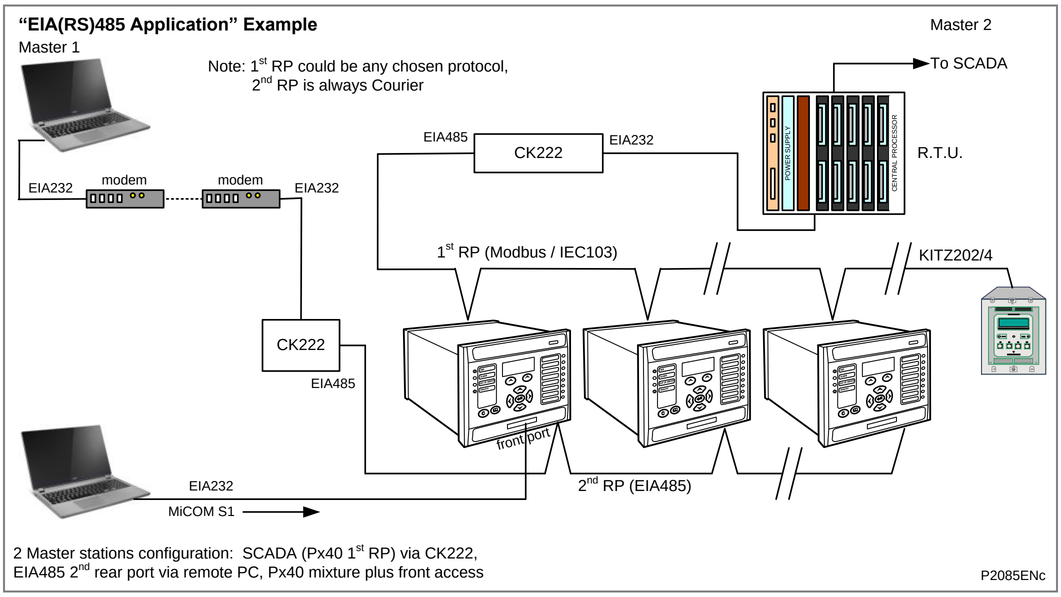


Figure 4 - Second rear port EIA(RS)485 example

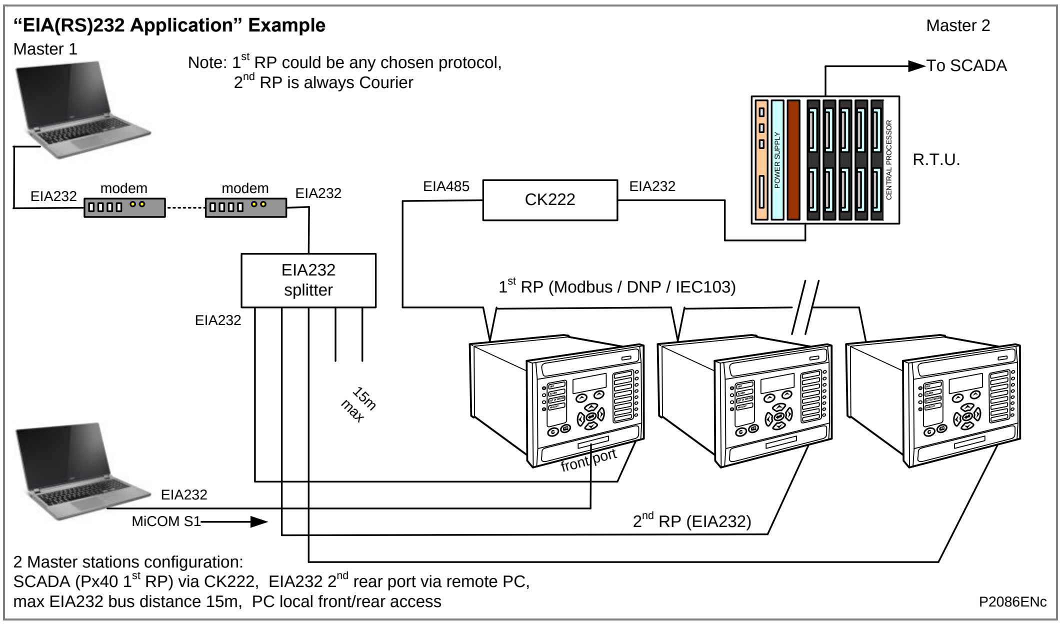


Figure 5 - Second rear port EIA(RS)232 example

2.6 SK5 Port Connection

The lower 9-way D-type connector (SK5) is currently unsupported.
Do not connect to this port.

3 COURIER INTERFACE

3.1 Courier Protocol

Courier is a Schneider Electric communication protocol. The concept of the protocol is that a standard set of commands is used to access a database of settings and data in the relay. This allows a generic master to be able to communicate with different slave devices. The application-specific aspects are contained in the database rather than the commands used to interrogate it, so the master station does not need to be preconfigured.

The same protocol can be used through two physical links K-Bus or EIA(RS)-232.

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. 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. Also it is not possible to connect K-Bus to an EIA(RS)-485 computer port. A protocol converter, such as the KITZ101, should be used for this purpose.

For a detailed description of the Courier protocol, command-set and link description, see the following documentation:

R6509	K-Bus Interface Guide
R6510	IEC60870 Interface Guide
R6511	Courier Protocol
R6512	Courier User Guide

3.2 Front Courier Port

The front EIA(RS)-232 9 pin port supports the Courier protocol for one-to-one communication. This port complies with EIA(RS)-574; the 9-pin version of EIA(RS)-232, see www.tiaonline.org. It is designed for use during installation and commissioning/maintenance and is not suitable for permanent connection. Since this interface is not 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 is 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.
  - Although automatic extraction of event and disturbance records is not supported, it is possible to manually access this data through the front port.

3.3 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 marked with an asterisk (*) are not supported through the front Courier port.*

3.4 Courier Database

The Courier database is two-dimensional. Each cell in the database is 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, for example, 0A02 is column 0A (10 decimal) row 02. Associated settings or data are part of the same column. Row zero of the column has a text string to identify the contents of the column and to act as a column heading.

The *Relay Menu Database document* contains the complete database definition for the relay. For each cell location the following information is stated:

- Cell Text
- Cell Data type
- 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)

3.5 Setting Changes

(See R6512, Courier User Guide - Chapter 9)
Courier provides two mechanisms for making setting changes, both of these are supported by the relay. Either method can be used for editing any of the settings in the relay database.

3.5.1 Method 1

This uses a combination of three commands to perform a settings change:

Enter Setting Mode	Checks that the cell is settable and returns the limits.
Preload Setting	Places a new value to the cell. This value is echoed to ensure that setting corruption has not taken place. The validity of the setting is not checked by this action.
Execute Setting	Confirms the setting change. If the change is valid, a positive response is returned. If the setting change fails, an error response is returned.
Abort Setting	This command can be used to abandon the setting change.

This is the most secure method. It is ideally suited to on-line editors because the setting limits are taken from the relay before the setting change is made. However, this method can be slow if many settings are being changed because three commands are required for each change.

3.5.2 Method 2

The **Set Value** command can be used to directly change a setting, the response to this command is either a positive confirm or an error code to indicate the nature of a failure. This command can be used to implement a setting more rapidly than the previous method, however the limits are not extracted from the relay. This method is most suitable for off-line setting editors such as MiCOM S1 Studio, or for issuing preconfigured (SCADA) control commands.

3.5.3 Relay Settings

There are three categories of settings in 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.

3.5.4 Setting Transfer Mode

If it is necessary to transfer all of the relay settings to or from the relay, a cell in 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.

3.6 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.

3.6.1 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 through the rear Courier port.

When new event information is created, the Event bit is set in 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 responds with the event data, which is 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, the event bit is reset. If there are more events still to be extracted, the next event can be accessed using the **Send Event** command as before.

3.6.2 Event Types

Events are created by the relay under these 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)

3.6.3 Event Format

The Send Event command results in these fields being returned by the relay:

- Cell reference
- Time stamp
- Cell text
- Cell value

The *Relay Menu Database* document for the relevant product, 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 return a Courier Type 3 event, which contains the above fields 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 in the record. The extended data can be extracted from the relay by uploading the text and data from the column.

3.6.4 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 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 from 250 stored events. 0 selects the most recent record and 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), the remainder of the column contains the additional information.

Fault Record Selection (Row 05)

> This cell can be used to select a fault record directly, using a value between 0 and 4 to select one of up to five stored fault records. (0 is the most recent fault and 4 is the oldest). The column then contains 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. This cell operates in a similar way to the fault record selection.

If this column is used to extract event information from the relay, the number associated with a particular record changes when a new event or fault occurs.

3.7 Disturbance Record Extraction

The stored disturbance records in the relay are accessible in a compressed format through the Courier interface. The records are extracted using column B4. Cells required for extraction of uncompressed disturbance records are not supported.

Select Record Number (Row 01)

> This cell can be used to select the record to be extracted. Record 0 is the oldest unextracted record, already extracted older records are assigned positive values, and negative values are used for more recent records. To help automatic extraction through 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 can be extracted using the block transfer mechanism from cell B00B. The file extracted from the relay is in a compressed format. Use MiCOM S1 Studio to decompress this file and save the disturbance record in the COMTRADE format.

As has been stated, the rear Courier port can be used to extract disturbance records automatically as they occur. This operates using the standard Courier mechanism, see *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.

3.8 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 the Courier User Guide.

These 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 or 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 or download.

The PSL 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 because the data is compressed. MiCOM S1 Studio also performs checks on the validity of the settings before they are downloaded to the relay.

4 MODBUS INTERFACE

The MODBUS interface is a master/slave protocol and is defined by: www.modbus.org

MODBUS Serial Protocol Reference Guide: PI-MBUS-300 Rev. E

4.1 Serial Interface

The MODBUS interface uses the first rear EIA(RS)-485 (RS485) two-wire port “RP1” (or converted fiber optic port). The port is designated “EIA(RS)-485/K-Bus Port” on the external connection diagrams.

The interface uses the MODBUS RTU communication mode rather than the ASCII mode since it provides for more efficient use of the communication bandwidth and is in widespread use. This communication mode is defined by the MODBUS standard.

4.1.1 Character Framing

The character framing is 1 start bit, 8 data bits, either 1 parity bit and 1 stop bit, or 2 stop bits. This gives 11 bits per character.

4.1.2 Maximum MODBUS Query and Response Frame Size

The maximum query and response frame size is limited to 260 bytes in total. (This includes the frame header and CRC footer, as defined by the MODBUS protocol.).

4.1.3 User Configurable Communications Parameters

The following parameters can be configured for this port using the product’s front panel user interface (in the communications sub-menu):

- Baud rate: 9600, 19200, 38400 bps
- Device address: 1 - 247
- Parity: Odd, even, none.
- Inactivity time: 1 - 30 minutes

Note	*The inactivity timer is started (or restarted) whenever the active password level is reduced when a valid password is entered, or when a change is made to the setting scratchpad. When the timer expires, the password level is restored to its default level and any pending (uncommitted) setting changes on the scratch pad are discarded. The inactivity timer is disabled when the password level is at its default value and there are no settings pending on the scratchpad. See the Setting Changes section.*

The MODBUS interface communication parameters are not part of the product’s setting file and cannot be configured with MiCOM S1 Studio.

4.2 Supported MODBUS Query Functions

The MODBUS protocol provides numerous query functions, of which the product supports the subset in the following table. The product responds with exception code 01 if any other query function is received by it.

Query Function Code	MODBUS Query Name	Application / Interpretation
01	Read Coil Status	Read status of output contacts (0x addresses)
02	Read Input Status	Read status of opto-isolated status inputs (1x addresses)
03	Read Holding Registers	Read setting values (4x addresses)
04	Read Input Registers	Read measurement values (3x addresses)
06	Preset Single Register	Write single setting value (4x addresses)
07	Read Exception Status	Read relay status, same value as register 3x1
08	Diagnostics	
11	Fetch Communication Event Counter	Application defined by the MODBUS protocol specification
12	Fetch Communication Event Log	
16	Preset Multiple Registers (127 max)	Write multiple setting values (4x addresses)

Table 3 - MODBUS query functions supported by the product

4.3 MODBUS Response Code Interpretation

Code	MODBUS response name	Product interpretation
01	Illegal Function Code	The function code transmitted is not supported.
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, all changes in the request are discarded and this error response is 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 in range. Other values transmitted in the same packet are executed if they are in the range.
04	Slave Device Failure	An exception arose during the processing of the received query that is not covered by any of the other exception codes in this table.
05	Acknowledge	Not used.
06	Slave Device Busy	The write command cannot be implemented due to the product's internal database being locked by another interface. This response is also produced if the product is busy executing a previous request.

Table 4 - MODBUS response code interpretation

4.4 Maximum Query and Response Parameters

The following table shows the maximum amount of data that the product can process for each of the supported query functions (see the Supported MODBUS Query Functions section) and the maximum amount of data that can be sent in a corresponding response frame. The principal constraint is the maximum query and response frame size, as noted in the *Maximum MODBUS Query and Response Frame Size* section. Maximum MODBUS query and response frame size.

Query function code	MODBUS query name	Maximum query data request size	Maximum response data size
01	Read Coil Status	32 coils	32 coils
02	Read Input Status	32 inputs	32 inputs
03	Read Holding Registers	127 registers	127 registers
04	Read Input Registers	127 registers	127 registers
06	Preset Single Register	1 register	1 register
07	Read Exception Status	-	8 coils
08	Diagnostics	-	-
11	Fetch Communication Event Counter	-	-
12	Fetch Communication Event Log	-	70 bytes
16	Preset Multiple Registers	127 registers	127 registers

Table 5 - Maximum query and response parameters for supported queries

4.5 Register Mapping

4.5.1 Conventions

4.5.1.1 Memory Pages

The MODBUS specification associates a specific register address space to each query that has a data address field. The address spaces are often called memory pages because they are analogous to separate memory devices. A simplistic view of the queries in MODBUS is that a specified location in a specified memory device is being read from or written to. However, the product's implementation of such queries is not as a memory access but as a translation to an internal database query (see Note).

Note	*One consequence of this is that the granularity of the register address space (in the 3x and 4x memory pages) is governed by the size of the data item being requested from the internal database. Since this is often more than the 16 bits of an individual register, not all register addresses are valid. See the Register Data Types section for more details.*

Each MODBUS memory page has a name and an ID. The *MODBUS "memory" pages reference and application* table provides a summary of the memory pages, their Ids, and their application in the product.

It is common practice to prefix a decimal register address with the page ID and generally this is the style used in this document.

Memory page ID	MODBUS memory page name	Product application
0xxxx	Coil Status	Read and write access of the Output Relays.
1xxxx	Input Status	Read only access of the Opto-Isolated Status Inputs.
3xxxx	Input Registers	Read-only data access, such as measurements and records.
4xxxx	Holding Registers	Read and write data access, such as product configurations settings and control commands.
6xxxx	Extended Memory File	Not used or supported.
Note	*xxxx represents the addresses available in the page (0 to 9999).*	

Table 6 - MODBUS "memory" pages reference and application

4.5.1.2 MODBUS Register Identification

The MODBUS convention is to document register identifiers with ordinal values (first, second, third…) whereas the actual protocol uses memory-page based register addresses that begin with address zero. Therefore the first register in a memory page is register address zero, the second register is register address 1 and so on. In general, one must be subtracted from a register's identifier to find its equivalent address. The page number notation is not part of the address.

Example:

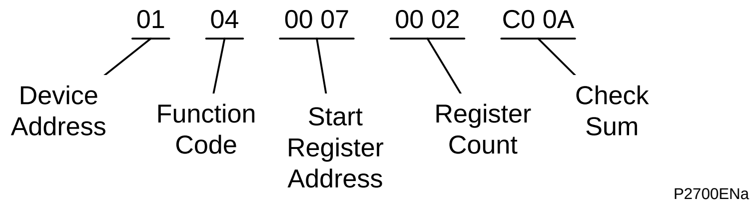
Task:

Obtain the status of the output contacts from the Schneider Electric MiCOM Pxxx device at address 1.

The output contact status is a 32-bit binary string held in input registers 3x8 and 3x9 (see the *Binary Status Information* section).

Select MODBUS function code 4 "Read input registers" and request two registers starting at input register address 7. Note the register address is one less than the required register ordinal.

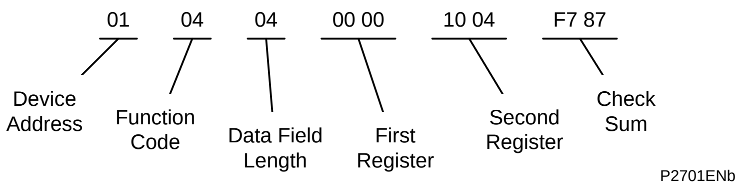
The MODBUS query frame is:



Note that the following frame data is shown in hexadecimal 8-bit bytes.

The frame is transmitted from left to right by the master device. The start register address, register count and check sum are all 16-bit numbers that are transmitted in a high byte - low byte order.

The query may elicit the following response: [4]



The frame was transmitted from left to right by the slave device. The response frame is valid because the eighth bit of the function code field is not set. The data field length is 4 bytes since the query was a read from two 16-bit registers. The data field consists of two pairs of bytes in a high byte - low byte order with the first requested register's data coming first. Therefore the request for the 32-bit output contact status starting at register 3x8 is 00001004h (1000000000100b), which shows that outputs 3 and 13 are energized and the remaining outputs are de-energized.

4.6 Register Map

For a complete map of the MODBUS addresses supported by the product, see the *Relay Menu Database document*.

The register map tables in this document include an Equivalent Courier Cell column. The cell identifiers relate to the product's internal Courier database and may be used in cross-reference with the Courier Protocol documentation or the product's front panel user interface documentation.

The Data Format column specifies the format of the data presented by the associated MODBUS register or registers. The *Register Data Types* section describes the formats used.

The right-hand columns in the tables show whether the register is used in a particular product model. An asterisk indicates that the model uses the register.

4.7 Measurement Values

This table presents all of the product’s available measurements: analog values and counters. An asterisk indicates that the model uses the register. Their values are refreshed approximately every second.

Measurement name	Measurement unit	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P342	P343	P344	P345
IA Magnitude	Amps	0201	3x00200	3x00201	G24	2	*			
IA-1 Magnitude	Amps	0201	3x00200	3x00201	G24	2		*	*	*
IA Phase Angle	Degrees	0202	3x00202		G30	1	*			
IA-1 Phase Angle	Degrees	0202	3x00202		G30	1		*	*	*
IB Magnitude	Amps	0203	3x00203	3x00204	G24	2	*			
IB-1 Magnitude	Amps	0203	3x00203	3x00204	G24	2		*	*	*
IB Phase Angle	Degrees	0204	3x00205		G30	1	*			
IB-1 Phase Angle	Degrees	0204	3x00205		G30	1		*	*	*
IC Magnitude	Amps	0205	3x00206	3x00207	G24	2	*			
IC-1 Magnitude	Amps	0205	3x00206	3x00207	G24	2		*	*	*
IC Phase Angle	Degrees	0206	3x00208		G30	1	*			
IC-1 Phase Angle	Degrees	0206	3x00208		G30	1		*	*	*
IN Measured Mag	Amps	0207	3x00209	3x00210	G24	2	*	*	*	*
IN Measured Ang	Degrees	0208	3x00211		G30	1	*	*	*	*
IN Derived Mag	Amps	0209	3x00212	3x00213	G24	2	*			
IN-1 Derived Mag	Amps	0209	3x00212	3x00213	G24	2		*	*	*
IN Derived Angle	Degrees	020A	3x00214		G30	1				
Isen Magnitude	Amps	020B	3x00215	3x00216	G24	2	*	*	*	*
Isen Angle	Degrees	020C	3x00217		G30	1	*	*	*	*
I1 Magnitude	Amps	020D	3x00218	3x00219	G24	2	*	*	*	*
I2 Magnitude	Amps	020E	3x00220	3x00221	G24	2	*	*	*	*
I0 Magnitude	Amps	020F	3x00222	3x00223	G24	2	*	*	*	*
I1 Phase Angle	Degrees	0241	3x00266		G30	1	*	*	*	*
I2 Phase Angle	Degrees	0243	3x00267		G30	1	*	*	*	*
I0 Phase Angle	Degrees	0245	3x00268		G30	1	*	*	*	*
IA RMS	Amps	0210	3x00224	3x00225	G24	2	*	*	*	*
IB RMS	Amps	0211	3x00226	3x00227	G24	2	*	*	*	*
IC RMS	Amps	0212	3x00228	3x00229	G24	2	*	*	*	*
IN-2 Derived Mag	Amps	0213	3x00273	3x00274	G24	2		*	*	*
VAB Magnitude	Volts	0214	3x00230	3x00231	G24	2	*	*	*	*
VAB Phase Angle	Degrees	0215	3x00232		G30	1	*	*	*	*
VBC Magnitude	Volts	0216	3x00233	3x00234	G24	2	*	*	*	*
VBC Phase Angle	Degrees	0217	3x00235		G30	1	*	*	*	*
VCA Magnitude	Volts	0218	3x00236	3x00237	G24	2	*	*	*	*
VCA Phase Angle	Degrees	0219	3x00238		G30	1	*	*	*	*
VAN Magnitude	Volts	021A	3x00239	3x00240	G24	2	*	*	*	*
VAN Phase Angle	Degrees	021B	3x00241		G30	1	*	*	*	*
VBN Magnitude	Volts	021C	3x00242	3x00243	G24	2	*	*	*	*
VBN Phase Angle	Degrees	021D	3x00244		G30	1	*	*	*	*

Measurement name	Measurement unit	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P342	P343	P344	P345
VCN Magnitude	Volts	021E	3x00245	3x00246	G24	2	*	*	*	*
VCN Phase Angle	Degrees	021F	3x00247		G30	1	*	*	*	*
VN Measured Mag	Volts	0220	3x00248	3x00249	G24	2	*	*		
VN1 Measured Mag	Volts	0220	3x00248	3x00249	G24	2			*	*
VN Measured Ang	Degrees	0221	3x00250		G30	1	*	*		
VN1 Measured Ang	Degrees	0221	3x00250		G30	1			*	*
VN2 Measured Mag	Volts	0250	3x00275	3x00276	G24	2			*	*
VN2 Measured Ang	Degrees	0251	3x00277		G30	1			*	*
VN Derived Mag	Volts	0222	3x00251	3x00252	G24	2	*	*	*	*
VN Derived Ang	Degrees	0223	3x00272[1]		G30	1	*	*	*	*
VN Derived Ang	Degrees	0223	3x00272[2]		G30	1	*	*	*	*
C/S Voltage Mag	Volts	0270	3x00281	3x00282	G24	2	*	*	*	*
C/S Voltage Ang	Degrees	0271	3x00283		G30	1	*	*	*	*
CS Gen-Bus Mag	Volts	0272	3x00284	3x00285	G24		*	*	*	*
CS Gen-Bus Angle	Degrees	0273	3x00286		G30	1	*	*	*	*
Slip Frequency	Hertz	0274	3x00287		G30	1	*	*	*	*
CS Frequency	Hertz	0275	3x00288		G30	1	*	*	*	*
V1 Magnitude	Volts	0224	3x00253	3x00254	G24	2	*	*	*	*
V2 Magnitude	Volts	0225	3x00255	3x00256	G24	2	*	*	*	*
V0 Magnitude	Volts	0226	3x00257	3x00258	G24	2	*	*	*	*
V1 Phase Angle	Degrees	0247	3x00269		G30	1	*	*	*	*
V2 Phase Angle	Degrees	0249	3x00270		G30	1	*	*	*	*
V0 Phase Angle	Degrees	024B	3x00271		G30	1	*	*	*	*
VAN RMS	Volts	0227	3x00259	3x00260	G24	2	*	*	*	*
VBN RMS	Volts	0228	3x00261	3x00262	G24	2	*	*	*	*
VCN RMS	Volts	0229	3x00263	3x00264	G24	2	*	*	*	*
Frequency	Hertz	022D	3x00265		G30	1	*	*	*	*
A Phase Watts	Watts	0301	3x00391	3x00392	G125	2	*	*	*	*
A Phase Watts	Watts	0301	3x00300	3x00302	G29	3	*	*	*	*
B Phase Watts	Watts	0302	3x00393	3x00394	G125	2	*	*	*	*
B Phase Watts	Watts	0302	3x00303	3x00305	G29	3	*	*	*	*

[1] Register 3x00272 was 3x00252 in P340 software revisions 01, 02, 03, 04, 05, 06, & 07. Register 3x00252 overlaps with the register pair beginning at 3x00251. As separate requests, these registers yielded the correct values. However, the overlap prevents a multi-register request that yields the required data. Moreover, the overlap could confuse certain master stations such that the value of assigned to the 3x00252 variable was the value yielded for the 3x00251 register-pair request. This is because it considers the slaves register map to be discrete 16 bit registers akin to a piece of memory and simply works to construct a copy of the slaves register memory.

[2] Register 3x00272 was 3x00252 in P340 software revisions 01, 02, 03, 04, 05, 06, & 07. Register 3x00252 overlaps with the register pair beginning at 3x00251. As separate requests, these registers yielded the correct values. However, the overlap prevents a multi-register request that yields the required data. Moreover, the overlap could confuse certain master stations such that the value of assigned to the 3x00252 variable was the value yielded for the 3x00251 register-pair request. This is because it considers the slaves register map to be discrete 16 bit registers akin to a piece of memory and simply works to construct a copy of the slaves register memory.

Measurement name	Measurement unit	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P342	P343	P344	P345
C Phase Watts	Watts	0303	3x00395	3x00396	G125	2	*	*	*	*
C Phase Watts	Watts	0303	3x00306	3x00308	G29	3	*	*	*	*
A Phase VArs	VAr	0304	3x00397	3x00398	G125	2	*	*	*	*
A Phase VArs	VAr	0304	3x00309	3x00311	G29	3	*	*	*	*
B Phase VArs	VAr	0305	3x00399	3x00400	G125	2	*	*	*	*
B Phase VArs	VAr	0305	3x00312	3x00314	G29	3	*	*	*	*
C Phase VArs	VAr	0306	3x00401	3x00402	G125	2	*	*	*	*
C Phase VArs	VAr	0306	3x00315	3x00317	G29	3	*	*	*	*
A Phase VA	VA	0307	3x00403	3x00404	G125	2	*	*	*	*
A Phase VA	VA	0307	3x00318	3x00320	G29	3	*	*	*	*
B Phase VA	VA	0308	3x00405	3x00406	G125	2	*	*	*	*
B Phase VA	VA	0308	3x00321	3x00323	G29	3	*	*	*	*
C Phase VA	VA	0309	3x00407	3x00408	G125	2	*	*	*	*
C Phase VA	VA	0309	3x00324	3x00326	G29	3	*	*	*	*
3 Phase Watts	Watts	030A	3x00409	3x00410	G125	2	*	*	*	*
3 Phase Watts	Watts	030A	3x00327	3x00329	G29	3	*	*	*	*
3 Phase VArs	VAr	030B	3x00411	3x00412	G125	2	*	*	*	*
3 Phase VArs	VAr	030B	3x00330	3x00332	G29	3	*	*	*	*
3 Phase VA	VA	030C	3x00413	3x00414	G125	2	*	*	*	*
3 Phase VA	VA	030C	3x00333	3x00335	G29	3	*	*	*	*
NPS Power S2	VA	030D	3x00336	3x00338	G29	3	*	*	*	*
NPS Power S2	VA	030D	3x00500	3x00501	G125	2	*	*	*	*
Single Phase Sensitive Watts	Watts	0420	3x00476	3x00477	G125	2	*	*	*	*
Single Phase Sensitive VArs	VAr	0421	3x00478	3x00479	G125	2	*	*	*	*
Single Phase Sensitive Power Angle	Degrees	0422	3x00480		G30	1	*	*	*	*
3Ph Power Factor	-	030E	3x00339		G30	1	*	*	*	*
APh Power Factor	-	030F	3x00340		G30	1	*	*	*	*
BPh Power Factor	-	0310	3x00341		G30	1	*	*	*	*
CPh Power Factor	-	0311	3x00342		G30	1	*	*	*	*
3 Phase WHours Fwd	Wh	0312	3x00415	3x00416	G125	2	*	*	*	*
3 Phase WHours Fwd	Wh	0312	3x00343	3x00345	G29	3	*	*	*	*
3 Phase WHours Rev	Wh	0313	3x00417	3x00418	G125	2	*	*	*	*
3 Phase WHours Rev	Wh	0313	3x00346	3x00348	G29	3	*	*	*	*
3 Phase VArHours Fwd	VArh	0314	3x00419	3x00420	G125	2	*	*	*	*
3 Phase VArHours Fwd	VArh	0314	3x00349	3x00351	G29	3	*	*	*	*
3 Phase VArHours Rev	VArh	0315	3x00421	3x00422	G125	2	*	*	*	*
3 Phase VArHours Rev	VArh	0315	3x00352	3x00354	G29	3	*	*	*	*
3 Phase W Fix Demand	Watts	0316	3x00423	3x00424	G125	2	*	*	*	*
3 Phase W Fix Demand	Watts	0316	3x00355	3x00357	G29	3	*	*	*	*
3 Phase VArs Fix Demand	VAr	0317	3x00425	3x00426	G125	2	*	*	*	*

Measurement name	Measurement unit	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P342	P343	P344	P345
3 Phase VArs Fix Demand	VAr	0317	3x00358	3x00360	G29	3	*	*	*	*
IA Fixed Demand	Amps	0318	3x00361	3x00362	G24	2	*	*	*	*
IB Fixed Demand	Amps	0319	3x00363	3x00364	G24	2	*	*	*	*
IC Fixed Demand	Amps	031A	3x00365	3x00366	G24	2	*	*	*	*
3 Phase W Roll Demand	Watts	031B	3x00427	3x00428	G125	2	*	*	*	*
3 Phase W Roll Demand	Watts	031B	3x00367	3x00369	G29	3	*	*	*	*
3 Phase VArs Roll Demand	VAr	031C	3x00429	3x00430	G125	2	*	*	*	*
3 Phase VArs Roll Demand	VAr	031C	3x00370	3x00372	G29	3	*	*	*	*
IA Roll Demand	Amps	031D	3x00373	3x00374	G24	2	*	*	*	*
IB Roll Demand	Amps	031E	3x00375	3x00376	G24	2	*	*	*	*
IC Roll Demand	Amps	031F	3x00377	3x00378	G24	2	*	*	*	*
3 Phase W Peak Demand	Watts	0320	3x00431	3x00432	G125	2	*	*	*	*
3Ph W Peak Dem	Watts	0320	3x00379	3x00381	G29	3	*	*	*	*
3 Phase VArs Peak Demand	VAr	0321	3x00433	3x00434	G125	2	*	*	*	*
3 Phase VArs Peak Demand	VAr	0321	3x00382	3x00384	G29	3	*	*	*	*
IA Peak Demand	Amps	0322	3x00385	3x00386	G24	2	*	*	*	*
IB Peak Demand	Amps	0323	3x00387	3x00388	G24	2	*	*	*	*
IC Peak Demand	Amps	0324	3x00389	3x00390	G24	2	*	*	*	*
CT2 NPS Power S2	Watts	0326	3x00596	3x00597	G125	2		*	*	*
CT2 NPS Power S2	Watts	0326	3x00593	3x00595	G29	3		*	*	*
IA-2 Magnitude	Amps	0401	3x00435	3x00436	G24	2		*	*	*
IA-2 Phase Angle	Degrees	0402	3x00437		G30	1		*	*	*
IB-2 Magnitude	Amps	0403	3x00438	3x00439	G24	2		*	*	*
IB-2 Phase Angle	Degrees	0404	3x00440		G30	1		*	*	*
IC-2 Magnitude	Amps	0405	3x00441	3x00442	G24	2		*	*	*
IC-2 Phase Angle	Degrees	0406	3x00443		G30	1		*	*	*
IA Differential	Amps	0407	3x00444	3x00445	G24	2		*	*	*
IB Differential	Amps	0408	3x00446	3x00447	G24	2		*	*	*
IC Differential	Amps	0409	3x00448	3x00449	G24	2		*	*	*
IA Bias	Amps	040A	3x00450	3x00451	G24	2		*	*	*
IB Bias	Amps	040B	3x00452	3x00453	G24	2		*	*	*
IC Bias	Amps	040C	3x00454	3x00455	G24	2		*	*	*
IREF Diff	Amps	040D	3x00456	3x00457	G24	2	*	*	*	*
IREF Bias	Amps	040E	3x00458	3x00459	G24	2	*	*	*	*
VN 3rd Harmonic	Volts	040F	3x00460	3x00461	G24	2		*	*	*
NPS Thermal	Percentage	0410	3x00462		G1	1	*	*	*	*
RTD 1	Celsius	0412	3x00463		G10	1	*	*	*	*
RTD 2	Celsius	0413	3x00464		G10	1	*	*	*	*
RTD 3	Celsius	0414	3x00465		G10	1	*	*	*	*
RTD 4	Celsius	0415	3x00466		G10	1	*	*	*	*
RTD 5	Celsius	0416	3x00467		G10	1	*	*	*	*

Measurement name	Measurement unit	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P342	P343	P344	P345
RTD 6	Celsius	0417	3x00468		G10	1	*	*	*	*
RTD 7	Celsius	0418	3x00469		G10	1	*	*	*	*
RTD 8	Celsius	0419	3x00470		G10	1	*	*	*	*
RTD 9	Celsius	041A	3x00471		G10	1	*	*	*	*
RTD 10	Celsius	041B	3x00472		G10	1	*	*	*	*
RTD Open Circuit	-	041C	3x00473		G108	1	*	*	*	*
RTD Short Circuit	-	041D	3x00474		G109	1	*	*	*	*
RTD Data Error	-	041E	3x00475		G110	1	*	*	*	*
Thermal Overload	Percentage	0423	3x00481		G1	1	*	*	*	*
CLIO Input 1	-	0425	3x00482	3x00483	G125	2	*	*	*	*
CLIO Input 2	-	0426	3x00484	3x00485	G125	2	*	*	*	*
CLIO Input 3	-	0427	3x00486	3x00487	G125	2	*	*	*	*
CLIO Input 4	-	0428	3x00488	3x00489	G125	2	*	*	*	*
CB Operations	-	0601	3x00600		G1	1	*	*	*	*
Total IA Broken	Amps	0602	3x00601	3x00602	G24	2	*	*	*	*
Total IB Broken	Amps	0603	3x00603	3x00604	G24	2	*	*	*	*
Total IC Broken	Amps	0604	3x00605	3x00606	G24	2	*	*	*	*
CB Operate Time	Seconds	0605	3x00607		G25	1	*	*	*	*
Freq Band 1 Time (s)	Seconds	0430	3x00502	3x00503	G27	2	*	*	*	*
Freq Band 2 Time (s)	Seconds	0434	3x00504	3x00505	G27	2	*	*	*	*
Freq Band 3 Time (s)	Seconds	0438	3x00506	3x00507	G27	2	*	*	*	*
Freq Band 4 Time (s)	Seconds	043C	3x00508	3x00509	G27	2	*	*	*	*
Freq Band 5 Time (s)	Seconds	0440	3x00510	3x00511	G27	2	*	*	*	*
Freq Band 6 Time (s)	Seconds	0444	3x00512	3x00513	G27	2	*	*	*	*
df/dt	Hertz/S	0448	3x00525	3x00526	G125	2	*	*	*	*
Volts Per Hertz	V/Hz	0450	3x00514	3x00515	G24	2	*	*	*	*
64S V Magnitude	Volts	0452	0x00516	0x00517	G24	2				*
64S I Magnitude	Amps	0454	0x00518	0x00519	G24	2				*
64S I Angle	Degrees	0455	0x00520		G30	1				*
64S R secondary	Ohms	0457	0x00521	0x00522	G125	2				*
64S R primary	Ohms	0458	0x00523	0x00524	G125	2				*
64R CL Input	Amps	0471	0x00539	0x00540	G125	2	*	*	*	*
64R R Fault	Ohms	0472	0x00541	0x00552	G125	2	*	*	*	*
IA Diff PU	Amps	0491	3x11300	3x11301	G24	2		*	*	*
IB Diff PU	Amps	0492	3x11302	3x11303	G24	2		*	*	*
IC Diff PU	Amps	0493	3x11304	3x11305	G24	2		*	*	*
IA Bias PU	Amps	0494	3x11306	3x11307	G24	2		*	*	*
IB Bias PU	Amps	0495	3x11308	3x11309	G24	2		*	*	*
IC Bias PU	Amps	0496	3x11310	3x11311	G24	2		*	*	*
IA Diff 2H	Amps	0497	3x11312	3x11313	G24	2		*	*	*
IB Diff 2H	Amps	0498	3x11314	3x11315	G24	2		*	*	*
IC Diff 2H	Amps	0499	3x11316	3x11317	G24	2		*	*	*

Measurement name	Measurement unit	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P342	P343	P344	P345
IA Diff 5H	Amps	049A	3x11318	3x11319	G24	2		*	*	*
IB Diff 5H	Amps	049B	3x11320	3x11321	G24	2		*	*	*
IC Diff 5H	Amps	049C	3x11322	3x11323	G24	2		*	*	*
CT2 I1 Mag	Amps	049D	3x11324	3x11325	G24	2		*	*	*
CT2 I1 Angle	Degrees	049E	3x11351		G30	1		*	*	*
CT2 I2 Mag	Amps	049F	3x11326	3x11327	G24	2		*	*	*
CT2 I2 Angle	Degrees	04A0	3x11352		G30	1		*	*	*
CT2 I0 Mag	Amps	04A1	3x11328	3x11329	G24	2		*	*	*
CT2 I0 Angle	Degrees	04A2	3x11353		G30	1		*	*	*
CT1 I2/I1	-	04A3	3x11330	3x11331	G24	2		*	*	*
CT2 I2/I1	-	04A4	3x11332	3x11333	G24	2		*	*	*
Hot Spot T	Celsius	0501	3x11334		G10	1	*	*	*	*
Top Oil T	Celsius	0502	3x11335		G10	1	*	*	*	*
Ambient T	Celsius	0504	3x11336		G10	1	*	*	*	*
TOL Pretrip left	Seconds	0505	3x11337	3x11338	G24	2	*	*	*	*
LOL status	-	0506	3x11339	3x11340	G24	2	*	*	*	*
Rate of LOL	-	0508	3x11341	3x11342	G24	2	*	*	*	*
LOL Ageing Fact	-	0509	3x11343	3x11344	G24	2	*	*	*	*
Lres at Design T	-	050A	3x11345	3x11346	G24	2	*	*	*	*
FAA,m	-	050B	3x11347	3x11348	G24	2	*	*	*	*
Lres at FAA,m	-	050C	3x11349	3x11350	G24	2	*	*	*	*

Table 7 - Measurement data available in the P340 product range

4.8 Binary Status Information

Binary status information is available for the product's optically-isolated status inputs (optos), relay contact outputs, alarm flags, control inputs, internal Digital Data Bus (DDB), and the front panel 25-pin test port (see Note).

Note	*The test port allows the product to be configured to map up to eight of its DDB signals (see the Relay Menu Database document) to eight output pins. The usual application is to control test equipment. However, since the test port output status is available on the MODBUS interface, it could be used to efficiently collect up to eight DDB signals.*

The product's internal DDB consists of 1023 binary-status flags. The allocation of the points in the DDB are largely product and version specific. See the *Relay Menu Database document*, for a definition of the product's DDB.

The relay-contact status information is available from the 0x "Coil Status" MODBUS page and from the 3x "Input Register" MODBUS page. For legacy reasons the information is duplicated in the 3x page with explicit registers (8 & 9) and in the DDB status register area (723 & 724).

The current state of the optically isolated status inputs is available from the 1x "Input Status" MODBUS page and from the 3x "Input Register" MODBUS page. The principal 3x registers are part of the DDB status register area (725 & 726). For legacy reasons, a single register at 3x00007 provides the status of the first 16 inputs.

The 0x "Coil Status" and 1x "Input Status" pages allow individual or blocks of binary status flags to be read. The resultant data is left aligned and transmitted in a big-endian (high-order to low-order) format in the response frame. Relay contact 1 is mapped to coil 1, contact 2 to coil 2 and so on. Similarly, opto input 1 is mapped to input 1, opto input 2 to input 2 and so on.

The following table presents the available 3x and 4x binary status information.

Name	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P341	P342	P343	P344	P345
Product Status	-	3x00001		G26	1	*	*	*	*	*
Opto I/P Status	0030	3x11025	3x11026	G8	2	*	*	*	*	*
Relay O/P Status	0040	3x00008	3x00009	G9	2	*	*	*	*	*
Alarm Status 1	0050	3x00011	3x00012	G96	2	*	*	*	*	*
Alarm Status 2	0051	3x00013	3x00014	G128	2	*	*	*	*	*
Alarm Status 3	0052	3x00015	3x00016	G228	2	*	*	*	*	*
Ctrl I/P Status	1201	4x00950	4x00951	G202	2	*	*	*	*	*
Relay Test Port Status	0F03	3x11022		G1	1	*	*	*	*	*
DDB 31 - 0	0F20	3x11023	3x11024	G27	2	*	*	*	*	*
DDB 63 - 32	0F21	3x11025	3x11026	G27	2	*	*	*	*	*
DDB 95 - 64	0F22	3x11027	3x11028	G27	2	*	*	*	*	*
DDB 127 - 96	0F23	3x11029	3x11030	G27	2	*	*	*	*	*
DDB 159 - 128	0F24	3x11031	3x11032	G27	2	*	*	*	*	*
DDB 191 - 160	0F25	3x11033	3x11034	G27	2	*	*	*	*	*
DDB 223 - 192	0F26	3x11035	3x11036	G27	2	*	*	*	*	*
DDB 255 - 224	0F27	3x11037	3x11038	G27	2	*	*	*	*	*
DDB 287 - 256	0F28	3x11039	3x11040	G27	2	*	*	*	*	*
DDB 319 - 288	0F29	3x11041	3x11042	G27	2	*	*	*	*	*
DDB 351 - 320	0F2A	3x11043	3x11044	G27	2	*	*	*	*	*
DDB 383 - 352	0F2B	3x11045	3x11046	G27	2	*	*	*	*	*

Name	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P341	P342	P343	P344	P345
DDB 415 - 384	0F2C	3x11047	3x11048	G27	2	*	*	*	*	*
DDB 447 - 416	0F2D	3x11049	3x11050	G27	2	*	*	*	*	*
DDB 479 - 448	0F2E	3x11051	3x11052	G27	2	*	*	*	*	*
DDB 511 - 480	0F2F	3x11053	3x11054	G27	2	*	*	*	*	*
DDB 543 - 512	0F30	3x11055	3x11056	G27	2	*	*	*	*	*
DDB 575 - 544	0F31	3x11057	3x11058	G27	2	*	*	*	*	*
DDB 607 - 576	0F32	3x11059	3x11060	G27	2	*	*	*	*	*
DDB 639 - 608	0F33	3x11061	3x11062	G27	2	*	*	*	*	*
DDB 671 - 640	0F34	3x11063	3x11064	G27	2	*	*	*	*	*
DDB 703 - 672	0F35	3x11065	3x11066	G27	2	*	*	*	*	*
DDB 735 - 704	0F36	3x11067	3x11068	G27	2	*	*	*	*	*
DDB 767 - 736	0F37	3x11069	3x11070	G27	2	*	*	*	*	*
DDB 799 - 768	0F38	3x11071	3x11072	G27	2	*	*	*	*	*
DDB 831 - 800	0F39	3x11073	3x11074	G27	2	*	*	*	*	*
DDB 863 - 832	0F3A	3x11075	3x11076	G27	2	*	*	*	*	*
DDB 895 - 864	0F3B	3x11077	3x11078	G27	2	*	*	*	*	*
DDB 927 - 896	0F3C	3x11079	3x11080	G27	2	*	*	*	*	*
DDB 959 - 928	0F3D	3x11081	3x11082	G27	2	*	*	*	*	*
DDB 991 - 960	0F3E	3x11083	3x11084	G27	2	*	*	*	*	*
DDB 1023 - 992	0F3F	3x11085	3x11086	G27	2	*	*	*	*	*
DDB 1055-1024	0F40	3x11087	3x11088	G27	2	*	*	*	*	*
DDB 1087-1056	0F41	3x11089	3x11090	G27	2	*	*	*	*	*
DDB 1119-1088	0F42	3x11091	3x11092	G27	2	*	*	*	*	*
DDB 1151-1120	0F43	3x11093	3x11094	G27	2	*	*	*	*	*
DDB 1183-1152	0F44	3x11095	3x11096	G27	2	*	*	*	*	*
DDB 1215-1184	0F45	3x11097	3x11098	G27	2	*	*	*	*	*
DDB 1247-1216	0F46	3x11099	3x11100	G27	2	*	*	*	*	*
DDB 1279-1248	0F47	3x11101	3x11102	G27	2	*	*	*	*	*
DDB 1311-1280	0F48	3x11103	3x11104	G27	2	*	*	*	*	*
DDB 1343-1312	0F49	3x11105	3x11106	G27	2	*	*	*	*	*
DDB 1375-1344	0F4A	3x11107	3x11108	G27	2	*	*	*	*	*
DDB 1407-1376	0F4B	3x11109	3x11110	G27	2	*	*	*	*	*
DDB 1439-1408	0F4C	3x11111	3x11112	G27	2	*	*	*	*	*
DDB 1471-1440	0F4D	3x11113	3x11114	G27	2	*	*	*	*	*
DDB 1503-1472	0F4E	3x11115	3x11116	G27	2	*	*	*	*	*
DDB 1535-1504	0F4F	3x11117	3x11118	G27	2	*	*	*	*	*
DDB 1567-1536	0F50	3x11119	3x11120	G27	2	*	*	*	*	*
DDB 1599-1568	0F51	3x11121	3x11122	G27	2	*	*	*	*	*
DDB 1631-1600	0F52	3x11123	3x11124	G27	2	*	*	*	*	*
DDB 1663-1632	0F53	3x11125	3x11126	G27	2	*	*	*	*	*
DDB 1695-1664	0F54	3x11127	3x11128	G27	2	*	*	*	*	*
DDB 1727-1696	0F55	3x11129	3x11130	G27	2	*	*	*	*	*

Name	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	P341	P342	P343	P344	P345
DDB 1759-1728	0F56	3x11131	3x11132	G27	2	*	*	*	*	*
DDB 1791-1760	0F57	3x11133	3x11134	G27	2	*	*	*	*	*
DDB 1823-1792	0F58	3x11135	3x11136	G27	2	*	*	*	*	*
DDB 1855-1824	0F59	3x11137	3x11138	G27	2	*	*	*	*	*
DDB 1887-1856	0F5A	3x11139	3x11140	G27	2	*	*	*	*	*
DDB 1919-1888	0F5B	3x11141	3x11142	G27	2	*	*	*	*	*
DDB 1951-1920	0F5C	3x11143	3x11144	G27	2	*	*	*	*	*
DDB 1983-1952	0F5D	3x11145	3x11146	G27	2	*	*	*	*	*
DDB 2015-1984	0F5E	3x11147	3x11148	G27	2	*	*	*	*	*
DDB 2047-2016	0F5F	3x11149	3x11150	G27	2	*	*	*	*	*

Table 8 - Binary status information available in the P340 product range

4.9 Measurement and Binary Status 3x Register Sets

The data available from the 3x input registers is arranged into register sets. A register set is a fixed collection of values in a contiguous block of register addresses. The advantage of this is that multiple values may be read with a single MODBUS query, function code 4 “Read Input Registers”, up to the maximum data limits of the query, see the *Maximum Query and Response Parameters* section.

The definition of a register-set is specified by the selection of a start and end address, which can span multiple contiguous values in the 3x Register, see the *Relay Menu Database document*. The only rule is that a register set must not result in an attempt to read only part of a multi-register data type, see the *Register Data Types* section. A register set can span unused register locations, in which case a value of zero is returned for each such register location.

Some examples of useful register sets are:

- For P34x:
  - 3x11203 to 3x11150 provide the DDB status
  - 3x391 to 3x408 provide the per phase power measurements in floating point format
  - 3x409 to 3x414 provide the three-phase power measurements in floating point format
  - 3x10106 to 3x10115 provide the ten RTD measurement values (P342/P343/P344/P345 only)

There are many other possibilities depending on your application and an appraisal of the 3x Register Map in the *Relay Menu Database document.* The capabilities of the MODBUS master device, performance targets, and communications latencies may also influence the degree to which multiple values are read as register sets, as opposed to individually.

4.10 Controls

The *Control (commands) available in the product range* table shows MODBUS 4x “Holding Registers” that allow the external system to control aspects of the product’s behavior, configuration, records, or items of plant connected to the product such as circuit breakers.

The **Command or setting** column indicates whether the control is a self-resetting “Command” or a state based “Setting”.

“Command” controls automatically return to their default value when the control action has been completed. This may cause problems with masters that try to verify write requests by reading back the value that was written.

“Setting” controls maintain the written value, assuming that it was accepted. For example, the **Active Settings** register reports the current active group on reads. The Active Setting Group register also accepts writes with a valid setting group number to change the active group to the one specified. This assumes that the setting group selection by optically isolated status inputs has not been enabled and that the specified group is enabled.

Entries without a defined setting range, as for the **min.**, **max.** and **step** columns, are binary-string values whose pattern is defined by its stated data type.

Name	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	Default value	Command or setting	Min	Max	Step	Password level	P341	P342	P343	P344	P345
Active Setting Group	0903	4x00404		G90	1	1	Setting	0	3	1	1	*	*	*	*	*
CB Trip/Close	0010	4x00021		G55	1	No Operation	Command	0	2	1	1	*	*	*	*	*
Reset NPS Thermal	0411	4x00104		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset RTD Flags	041F	4x00105		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset Thermal O/L	0424	4x00106		G11	1	No	Command	0	1	1	1	*	*	*	*	*
Reset Demand	0325	4x00103		G11	1	No	Command	0	1	1	1	*	*	*	*	*
Record Control	-	4x00401		G6	1	0	Setting					*	*	*	*	*
Test Mode	0F0D	4x00858		G119	1	Disabled	Setting	0	2	1	2	*	*	*	*	*
Test LEDs	0F10	4x00862		G94	1	No Operation	Command	0	1	1	2	*	*	*	*	*
Lockout Reset	0708	4x00206		G11	1	No	Command	0	1	1	2	*	*	*	*	*
Reset CB Data	0606	4x00150		G11	1	No	Command	0	1	1	1	*	*	*	*	*
Ctrl I/P Status	1201	4x00950	4x00951	G202	2	0	Setting				2	*	*	*	*	*
Control Input 1	1202	4x00952		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 2	1203	4x00953		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 3	1204	4x00954		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 4	1205	4x00955		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 5	1206	4x00956		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 6	1207	4x00957		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 7	1208	4x00958		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 8	1209	4x00959		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 9	120A	4x00960		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*

Name	Equivalent courier cell	Start register	End register	Data format	Data size (registers)	Default value	Command or setting	Min	Max	Step	Password level	P341	P342	P343	P344	P345
Control Input 10	120B	4x00961		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 11	120C	4x00962		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 12	120D	4x00963		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 13	120E	4x00964		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 14	120F	4x00965		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 15	1210	4x00966		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 16	1211	4x00967		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 17	1212	4x00968		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 18	1213	4x00969		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 19	1214	4x00970		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 20	1215	4x00971		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 21	1216	4x00972		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 22	1217	4x00973		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 23	1218	4x00974		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 24	1219	4x00975		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 25	121A	4x00976		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 26	121B	4x00977		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 27	121C	4x00978		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 28	121D	4x00979		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 29	121E	4x00980		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 30	121F	4x00981		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 31	1220	4x00982		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Control Input 32	1221	4x00983		G203	1	No Operation	Command	0	2	1	2	*	*	*	*	*
Reset Freq Band 1	0432	4x00107		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset Freq Band 2	0436	4x00108		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset Freq Band 3	043A	4x00109		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset Freq Band 4	043E	4x00110		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset Freq Band 5	0442	4x00111		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset Freq Band 6	0446	4x00112		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset Xthermal	0503	4x00113		G11	1	No	Command	0	1	1	1		*	*	*	*
Reset LOL	0507	4x00114		G11	1	No	Command	0	1	1	1		*	*	*	*

Table 9 - Control (commands) available in the P340 product range

4.11 Event Extraction

The product can store up to 512 event records in battery backed-up memory. An event record consists of a time stamp, a record type, and a set of information fields. The record type and the information fields record the event that occurred at the time captured by the time stamp.

The product has several classes of event record:

- Alarm events
- Opto-isolated status input events
- Relay contact output events
- Protection/DDB operation events
- Fault data capture events
- General events

The *Relay Menu Database document* specifies the available events. The product provides an “event filtering” feature that may be used to prevent specific events from being logged. The event filter is configured in the **Record Control** section of the product’s menu database in the MiCOM S1 Studio configuration tool.

The product supports two methods of event extraction providing either automatic or manual extraction of the stored event, fault, and maintenance records.

The product stores event, fault, and maintenance records in three separate queues. As entries are added to the fault and maintenance queues, a corresponding event is added to the event queue. Each queue is of different length and each queue may be individually cleared – see the *Event Record Delection* section. It is therefore possible to have a fault event or a maintenance event entry in the event queue with no corresponding entry in the associated queue because it has been overwritten or deleted.

The manual extraction procedure (see the *Manual Extraction Procedure section*) allows each of these three queues to be read independently.

The automatic extraction procedure (sss the *Automatic Extraction Procedure section*) reads records from the event queue. If the event record is a fault or a maintenance record, the record’s extended data is read also, if it is available from their queues.

Note	*Version 31 of the product introduced a new set of 3x registers for the presentation of the event and fault record data. These registers are used throughout the text of the following sub-sections. For legacy compatibility, the original registers are still provided. These are described as previous MODBUS addresses in the Relay Menu Database document. They should not be used for new installations. See the* ***Legacy Event Record Support*** *section for additional information.*

4.11.1 Manual Extraction Procedure

There are three registers used to manually select stored records. For each of these registers, zero represents the most-recent stored record. For example:

- 4x00100 - Select Event, 0 to 511.
  511 was 249 in P24x software version 57, P34x/P64x software versions 01, 02, 03, 04, 05, 06, & 07, since they only stored 250 event records.
- 4x00101 - Select Fault, 0 to 4
- 4x00102 - Select Maintenance Record, 0 to 4

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.

4.11.2 Automatic Extraction Procedure

Automatic event-record extraction allows records to be extracted as they occur. Event records are extracted in sequential order, including any fault or maintenance data that may be associated with an event.

The MODBUS master can determine whether the product has any events stored that have not yet been extracted. This is done by reading the product's status register 3x00001 (G26 data type). If the event bit of this register is set, the product contains event records that have not yet been extracted.

To select the next event for sequential extraction, the master station writes a value of one to the record selection register 4x00400 (G18 data type). The event data, plus any fault or maintenance data, can be read from the registers specified in the *Record Data* section. Once the data has been read, the event record is marked. This is done by writing a value of 2 to register 4x00400. The G18 data type consists of bit fields. Therefore it is also possible to both mark the current record as read and automatically select the next unread record. This is done by writing a value of 3 to the register.

When the last (most recent) record is accepted, the event flag in the status register (3x00001) resets. If the last record is accepted by writing a value of 3 to the record selection register (4x00400), a dummy record appears in the event-record registers with an "Event Type" value of 255. Selecting another record when none are available gives a MODBUS exception code 3, "Invalid value" (see the *MODBUS Response Code Interpretation* section).

One possible event record extraction procedure is shown in the following *Automatic event extraction procedure* diagram.

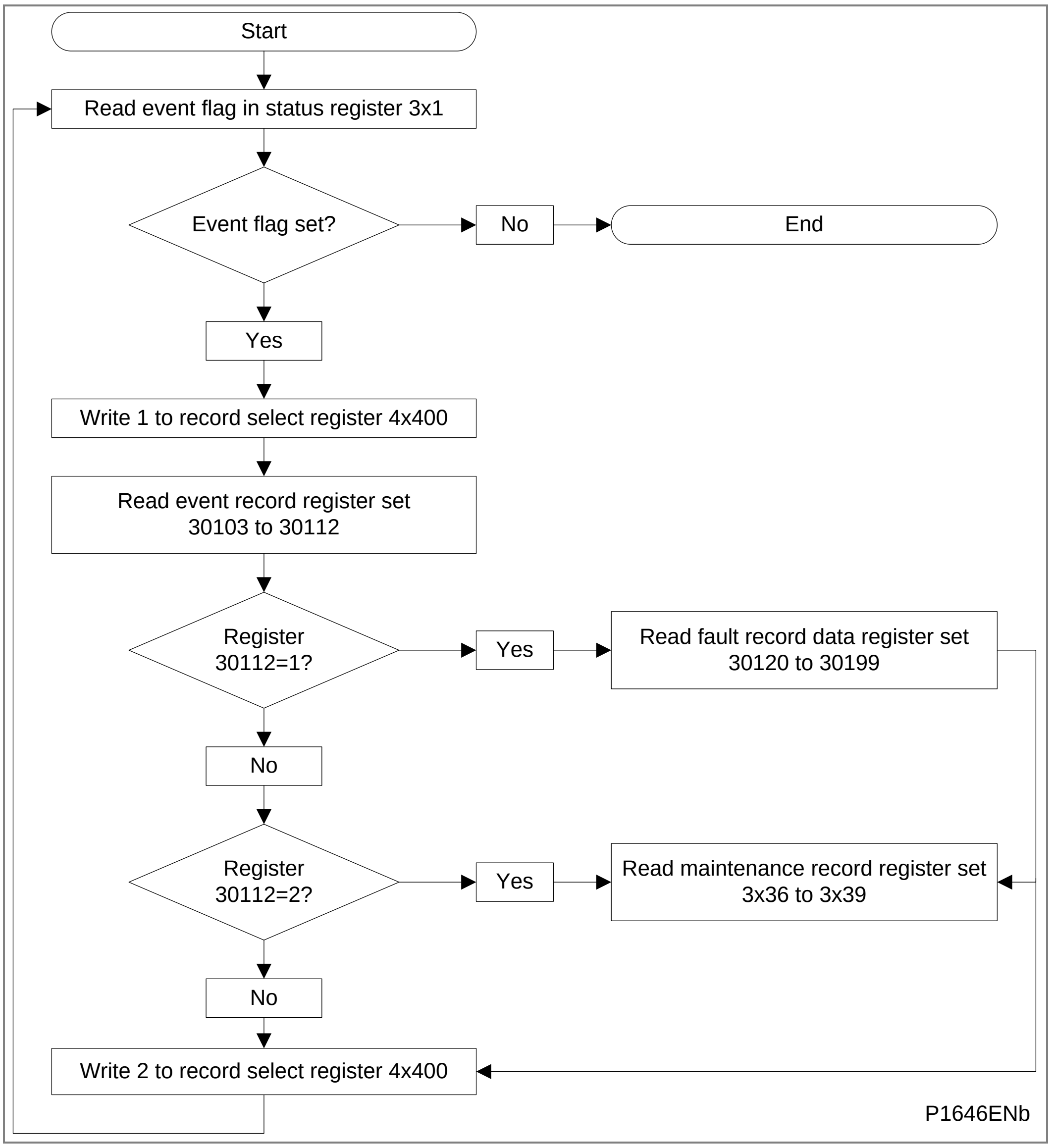


Figure 6 - Automatic event extraction procedure

4.11.3 Record Data

The location and format of the registers used to access the record data is the same whether they have been selected using manual or automatic extraction mechanisms, see the *Manual Extraction Procedure* and *Automatic Extraction Procedure* sections.

Description	Register	Length (registers)	Comments
Time Stamp	3x10103	4	See G12 data type the Relay Menu Database, *P341/EN MD*.
Event Type	3x10107	1	Indicates the type of the event record. See G13 data type in the Relay Menu Database, *P341/EN MD* (additionally, a value of 255 indicates that the end of the event log has been reached).
Event Value	3x10108	2	Contains the associated status register value, as a string of binary flags, for relay-contact, opto-input, alarm, and protection events. Otherwise, it will have a value of zero. When a status value is supplied, the value represents the recorded value of the event types associated register pair, as indicated by the Event Origin value. Note - the protection-event status information is the value of the DDB status word that contains the protection DDB that caused the event
Event Origin	3x10110	1	The Event Original value indicates the MODBUS Register pair where the change occurred. (Note subtracting 3000 from the Event Origin value results in the MODBUS 3x memory-page register ID, subtracting one from this results in the MODBUS register address - see section 0. The resultant register address can be used in a function code 4 MODBUS query) Possible values are: 11 (3x00011): Alarm Status 1 event 13 (3x00013): Alarm Status 2 event 15 (3x00015: Alarm Status 3 event 23 (3x11023): Relay contact event (2 registers: DDB 0-31 status) 25 (3x11025): Status input event (2 registers: DDB 32-63 status) 27 to 85 (3x11027 – 3x11085): Protection events (Indicates the 32 bit DDB status word that was the origin of the event) For General events, Fault events, and Maintenance events a value of zero will be returned.
Event Index	3x10111	1	The Event Index value is used to distinguish between events with the same Event Type and Event Origin. The registers value depends on the type of the event: For protection events, the value is the ID of the DDB that caused the event. For alarm events, the value is the ID of the alarm that caused the event. In both cases, the value includes the direction of the state transition in the most significant bit. This direction bit is 1 for a 0-1 (low to high) change, and 0 for a 1-0 (high to low) change. For all other types of events, it will have a value of zero.
Additional Data Present	3x10112	1	Indicates whether the record has additional data. 0: Indicates that there is no additional data. 1: Indicates that fault record data can be read from 3x10020 to 3x10999. (Note - the exact number of fault record registers depends on the individual product - see Relay Menu Database, *P341/EN MD).* 2: Indicates that maintenance record data can be read from registers 3x36 to 3x39.

Table 10 - Event record extraction registers

If a fault record or maintenance record is directly selected using the manual mechanism, the data can be read from the fault or maintenance data register ranges specified in the *Maintenance record types* table. The event record data in registers 3x10003 to 3x10012 is not valid.

See the *Relay Menu Database document* for the record values for each event.

The general procedure for decoding an event record is to use the value of the **Event Type** field combined with the value of the **Event Index** field to uniquely identify the event. The exceptions to this are event types 4, 5, 7, 8, & 9.

Event types 4 **Relay Contact Output Events** and 5 **Opto-Isolated Status Input Events** only provide the value of the input or output status register (as indicated by the Event Origin value) when the event occurred. If event transition information for each input or output is required, it must be deduced by comparing the event value with the previous event value (for identically-typed events records).

Event type 7 **General Event** events are solely identified by their **Event Value**.

Event types 8 **Fault Record** and 9 **Maintenance Record** require additional registers to be read when the associated additional data is available (see Note). The Fault record registers in the range 3x10020 to 3x10999 (the exact number of registers depends on the individual product) are documented in the 3x register-map in the *Relay Menu Database document*. The two additional 32-bit maintenance record register-pairs consist of a maintenance record type (register pair 3x36/7) and a type-specific error code (register pair 3x38/9). The *Maintenance record types* table lists the different types of maintenance record available from the product.

Note	*As noted at the beginning of the Event Extraction section, it should not be assumed that the additional data is available for fault and maintenance record events.*

Maintenance record	Front panel text	Record type 3x00036
Power on test errors (non-fatal)		
Watchdog 1 failure (fast)	Fast W'Dog Error	0
Battery fail	Battery Failure	1
Battery-backed RAM failure	BBRAM Failure	2
Field voltage failure	Field Volt Fail	3
Ribbon bus check failure	Bus Reset Error	4
Watchdog 2 failure (slow)	Slow W'Dog Error	5
Continuous self-test errors		
SRAM bus failure	SRAM Failure Bus	6
SRAM cell failure	SRAM Failure Blk.	7
Flash EPROM checksum failure	FLASH Failure	8
Program code verify failure	Code Verify Fail	9
Battery-backed RAM failure	BBRAM Failure	10
Battery fail	Battery Failure	11
Field Voltage failure	Field Volt Fail	12
EEPROM failure	EEPROM Failure	13
Fatal software exception	Software Failure	14
Incorrect hardware configuration	H/W Verify Fail	15
Software exception (typically non-fatal)	Non Standard	16
Analog module failure	Ana. Sample Fail	17
Ethernet card error	NIC Soft Error	18

Table 11 - Maintenance record types

4.11.4 Event Record Deletion

It is possible to independently delete (“clear”) the stored event, fault, and maintenance record queues. This is done by writing a value of 1, 2, or 3 to register 4x401 (G6 data type), respectively.

Register 4x401 also provides an option to reset the product’s front panel indications, which has the same effect as pressing the front panel “Clear” key when viewing alarm indications using the front panel user interface. This is done by writing a value of 4 to register 4x401.

See also the *Disturbance Record Deletion* section for details about deleting disturbance records.

4.11.5 Legacy Event Record Support

Version 57 of P24x and Version 31 of P34x product introduced a new set of 3x registers for the presentation of the event and fault record data. For legacy compatibility, the original registers are supported and are described in this section. They should not be used for new installations and they are correspondingly described as previous MODBUS address in the 3x-register table in the *Relay Menu Database document*.

The *Correspondence of obsolete event record 3x registers with their counterparts* table provides a mapping between the obsolete event record 3x-registers and the registers used in the event record discussions in the previous sub-sections.

The obsolete fault record data between registers 3x113 and 3x199, and 3x490 and 3x499, now exists between registers 30120 and 30199. In comparison with the obsolete fault record data, the data between registers 30120 and 30199 is ordered slightly differently and it contains new data values. These new values since version 31 of the product are not available in the obsolete fault-record register sets.

The maintenance-record registers 3x36 to 3x39 remain unaffected by this evolution.

Description	Obsolete register	Length (registers)	Corresponds to register
Number of stored event records	3x00100	1	3x10100
Number of stored fault records	3x00101	1	3x10101
Number of stored maintenance records	3x00102	1	3x10102
Time Stamp	3x00103	4	3x10103
Event Type	3x00107	1	3x10107
Event Value	3x00108	2	3x10108
Event Origin	3x00110	1	3x10110
Event Index	3x00111	1	3x10111
Additional Data Present	3x00112	1	3x10112

Table 12 - Obsolete event record 3x registers with their counterparts

4.12 Disturbance Record Extraction

The product provides facilities for both manual and automatic extraction of disturbance records. The two methods differ only in the mechanism for selecting a disturbance record; the method for extracting the data and the format of the data are identical.

Records extracted are presented in IEEE COMTRADE format. This involves extracting two files: an ASCII text configuration file, and a binary data file.

Each file is extracted by repeatedly reading a data-page until all of the file’s data has been transferred. The data-page is made up of 127 registers; providing a maximum of 254 bytes for each register block request.

4.12.1 Interface Registers

The following set of registers is presented to the master station to support the extraction of uncompressed disturbance records:

Register	Name	Description
3x00001	Status register	Provides the status of the product 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' in bit "b4" indicates the presence of one or more disturbance records.
3x00800	Number of stored disturbances	Indicates the total number of disturbance records currently stored in the product, 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 product. This is an integer value used in conjunction with the 'Number 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 No 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 to 3x00933	Record time stamp	These registers return the timestamp of the disturbance record.
3x00802	Number of registers in data page	This register informs the master station of the number of registers in the data page that are populated.
3x00803 to 3x00929	Data page registers	These 127 registers are used to transfer data from the product to the master station.
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.

Table 13 - Disturbance record extraction registers

The Disturbance Record status register will report one of these values:

State	No	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 product is currently processing data.

State	No	Description
Page ready		The data page has been populated and the master can now safely read the data.
Configuration complete		All of the configuration data has been read without error.
Record complete	4	All of the disturbance data has been extracted.
Disturbance overwritten	5	An error occurred during the extraction process where the disturbance being extracted was overwritten by a new record.
No unextracted disturbances	6	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	7	An attempt was made by the master station to manually select a record that did not exist in the product.
Command out of sequence	8	The master station issued a command to the product that was not expected during the extraction process.

Table 14 - Disturbance record status register (3x934) values

4.12.2 Extraction Procedure

The following procedure must be used to extract disturbance records from the product. 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).

4.12.2.1 Manual Extraction Procedure

The procedure used to extract a disturbance manually is shown in the following *Manual selection of a disturbance record* diagram. The manual method of extraction does not allow for the acceptance of disturbance records.

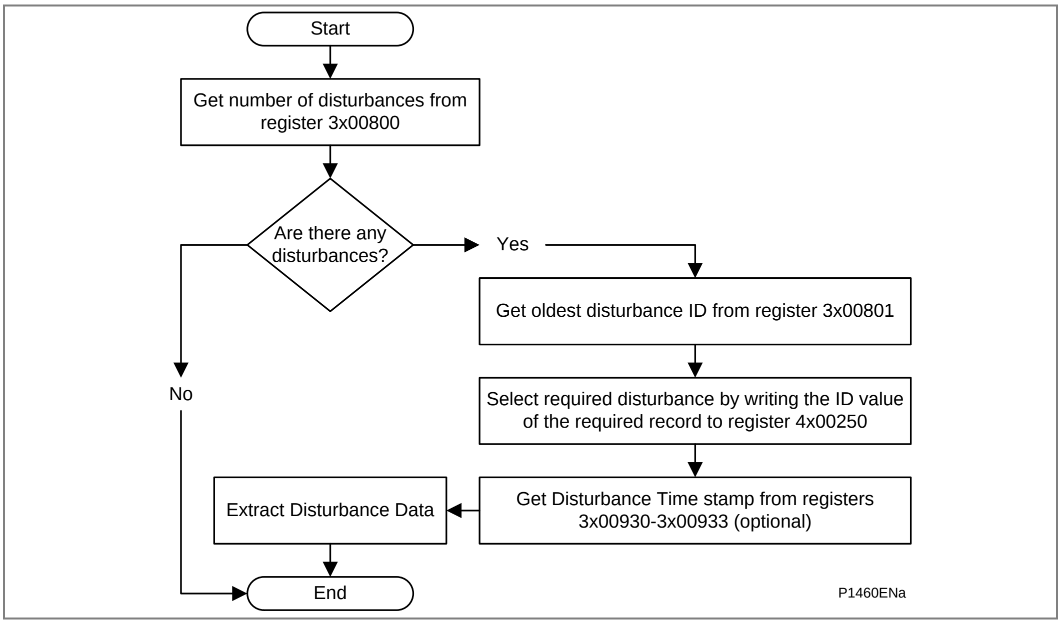


Figure 7 - Manual selection of a disturbance record

4.12.2.2 Automatic Extraction Procedure - Option 1

There are two methods that can be used for automatically extracting disturbances. The procedure for the first method is shown in the *Automatic selection of a disturbance - option 1* diagram. This also shows the acceptance of the disturbance record once the extraction is complete.

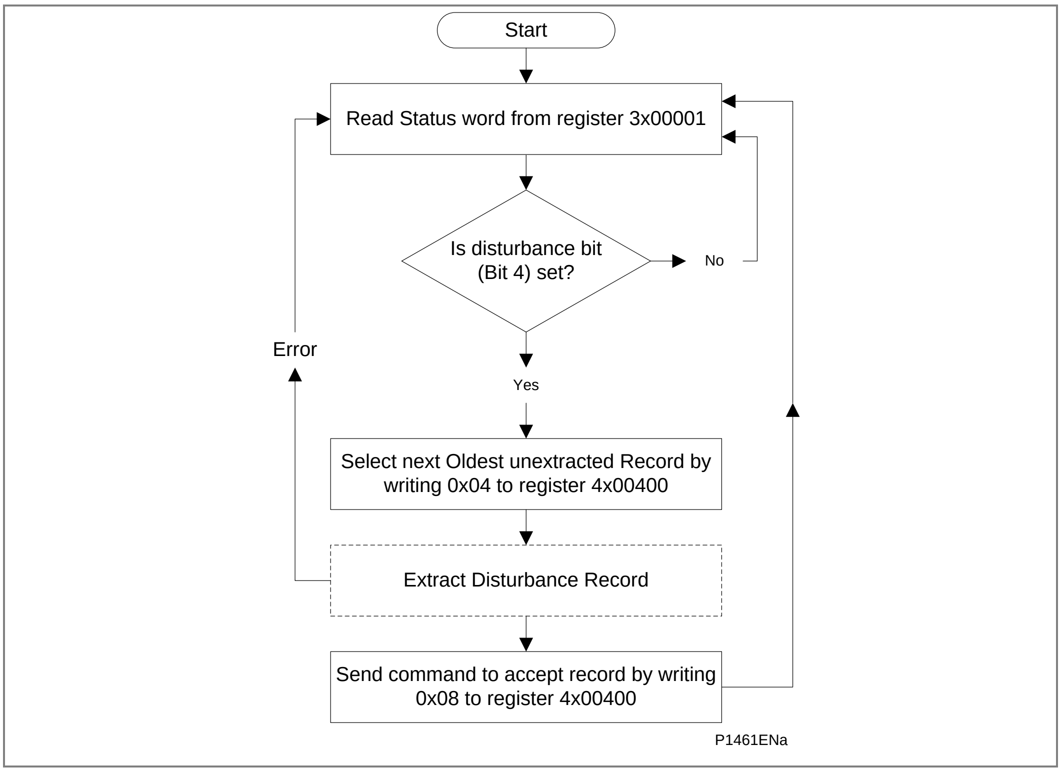


Figure 8 - Automatic selection of a disturbance - option 1

4.12.2.3 Automatic Extraction Procedure - Option 2

The second method that can be used for automatic extraction is shown in the *Automatic selection of a disturbance - option 2* diagram. This also shows the acceptance of the disturbance record once the extraction is complete.

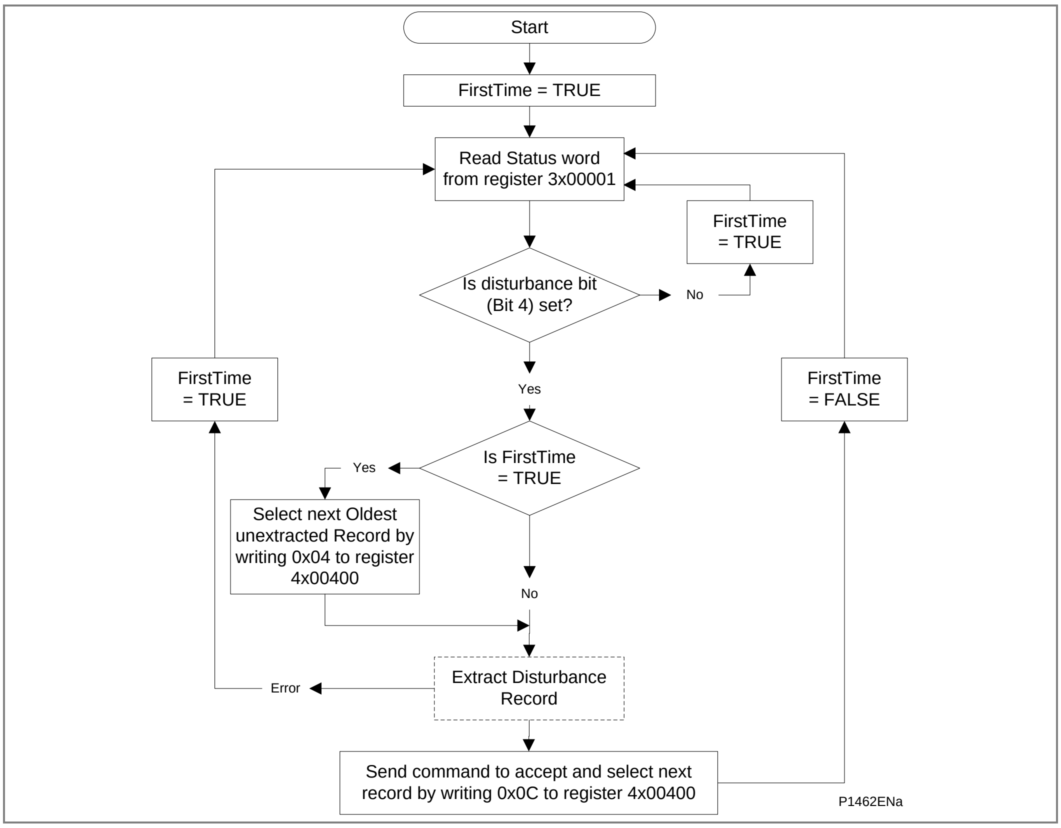


Figure 9 - Automatic selection of a disturbance - option 2

4.12.2.4 Extracting the Disturbance Data

Extraction of a selected disturbance record is a two-stage process. This involves first reading the configuration file, then the data file. The *Extracting the COMTRADE configuration file* diagram shows how the configuration file is read and *the Extracting the COMTRADE binary data file* diagram shows how the data file is extracted.

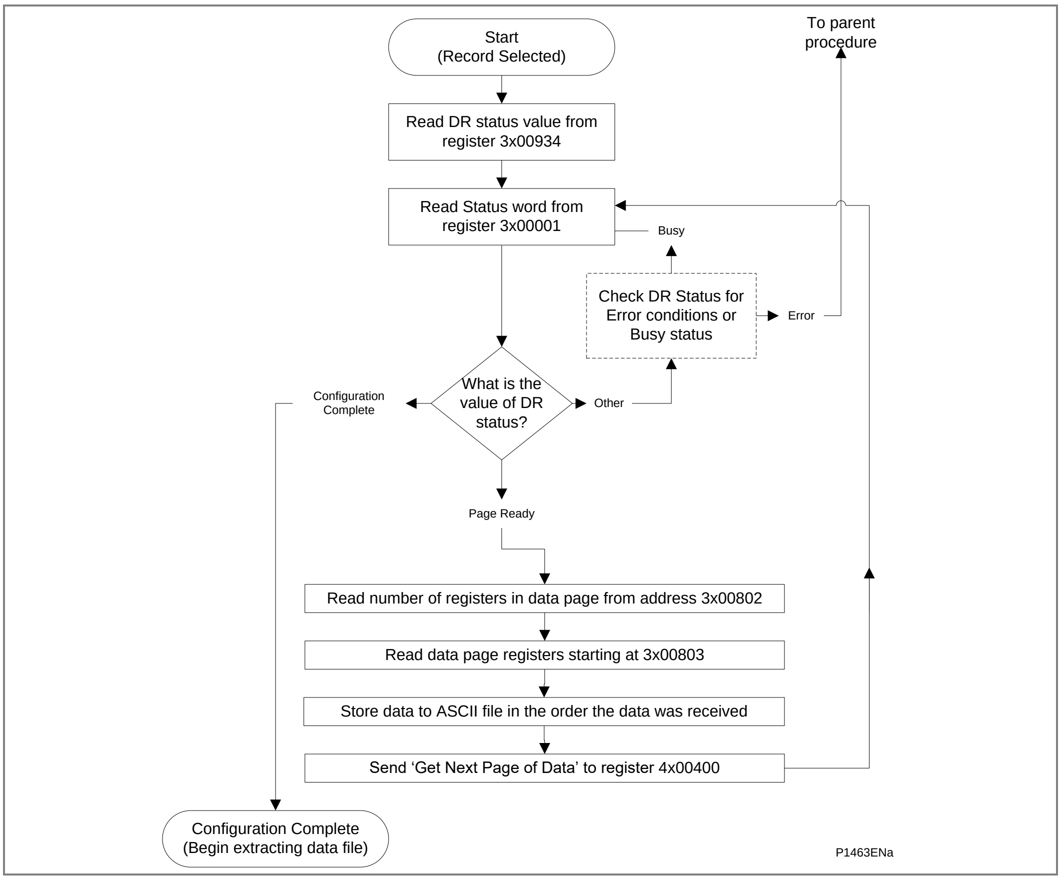


Figure 10 - Extracting the COMTRADE configuration file

Figure 11 shows how the data file is extracted:

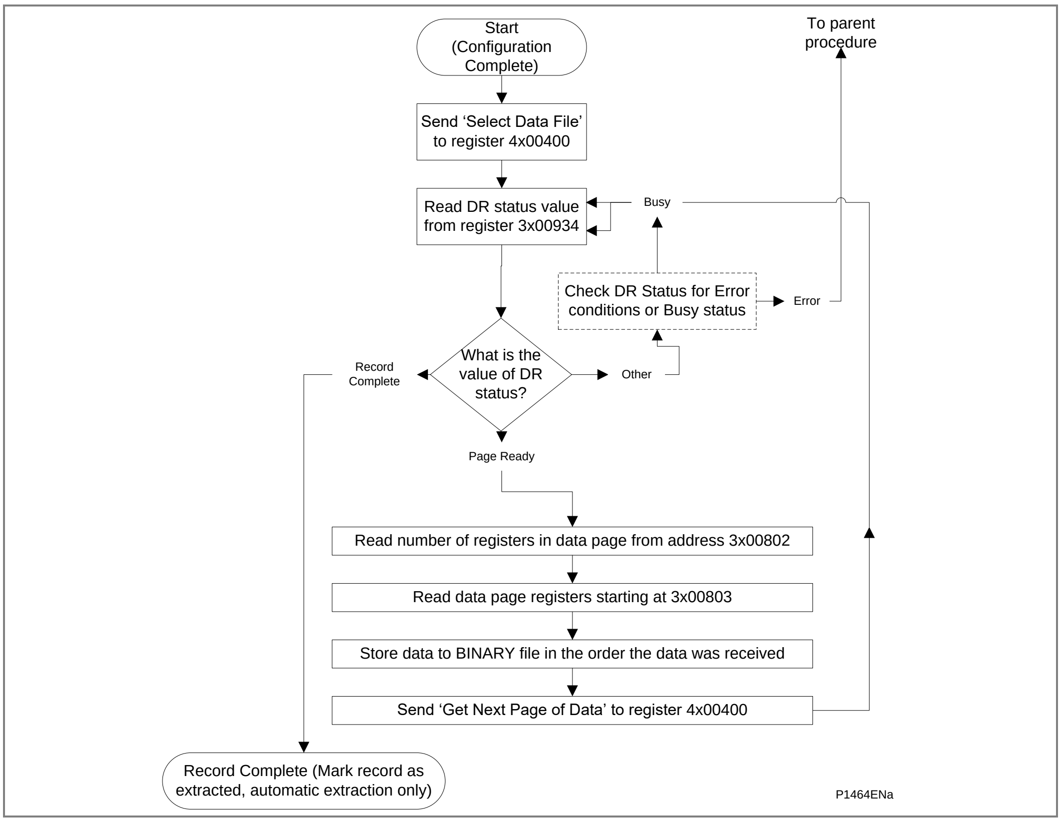


Figure 11 - Extracting the COMTRADE binary data file

During the extraction of a COMTRADE file, an error may occur that is reported in the disturbance record status register, 3x934. This can be caused by the product overwriting the record that is being extracted. It can also be caused by the master issuing a command that is not in the bounds of the extraction procedure.

4.12.3 Storage of Extracted Data

The extracted data needs to be written to two separate files. The first is the configuration file, which is in ASCII text format, and the second is the data file, which is in a binary format.

4.12.3.1 Storing the Configuration File

As the configuration data is extracted from the product, it should be stored to an ASCII text file with a '.cfg' file extension. Each register in the page is a G1 format 16-bit unsigned integer that is transmitted in big-endian byte order. The master must write the configuration file page-data to the file in ascending register order with each register's high order byte written before its low order byte, until all the pages have been processed.

4.12.3.2 Storing the Binary Data File

As the binary data is extracted from the product, it should be stored to a binary file with the same name as the configuration file, but with a '.dat' file extension instead of the '.cfg' extension. Each register in the page is a G1-format 16-bit unsigned integer that is transmitted in big-endian byte order. The master must write the page data to a file in ascending register order with each register's high order byte written before its low order byte until all the pages have been processed.

4.12.4 Disturbance Record Deletion

All of the disturbance records stored in the product can be deleted ("cleared") by writing 5 to the record control register 4x401 (G6 data type). See the *Event Record Deletion* section for details on event record deletion.

4.13 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 in 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 product settings are 4xxxx page registers; see the *Relay Menu Database document*. 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 product does not support write access to sub-parts of multi-register data types.
- The first address for a multi-register write must be a valid address. If there are unmapped addresses in the range that is written to, the data associated with these addresses are discarded.
- If a write operation is performed with values that are out of range, an "illegal data" response code is produced. Valid setting values in the same write operation are executed.
- If a write operation is performed attempting to change registers that require a higher level of password access than is currently enabled, all setting changes in the write operation are discarded.

4.13.1 Password Protection

The product's settings can be subject to Password protection. The level of password protection required to change a setting is indicated in the 4x register-map table in the *Relay Menu Database document*. 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:

Models without Cyber Security

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

Models with Cyber Security

420008 - 420011 Setting to change password level 1

420016 - 420019 Setting to change password level 2

420024 - 420027 Setting to change password level 1

4.13.2 Control and Support Settings

Control and support settings are committed immediately when a value is written to such a register. The MODBUS registers in this category are:

- 4x00000-4x00599
- 4x00700-4x00999
- 4x02049 to 4x02052
- 4x10000-4x10999

4.13.2.1 Time Synchronization

The value of the product's real time clock can be set by writing the desired time (see the *Date and Time Format (Data Type G12)* section) to registers 4x02049 through 4x02052. These registers are standard to Schneider Electric MiCOM products, which makes it easier to broadcast a time synchronization packet, being a block write to the time setting registers sent to slave address zero.

When the product's time has been set using these registers, the Time Synchronized flag in the MODBUS Status Register (3x1: type G26) is set. The product automatically clears this flag if more than five minutes has elapsed since these registers were last written to.

A "Time synchronization" event is logged if the new time value is more than two seconds different to the current value.

4.13.3 Disturbance Recorder Configuration Settings

Disturbance recorder configuration-settings are written to a scratchpad memory area. A confirmation procedure is required to commit the contents of the scratchpad to the disturbance recorder's set-up, which ensures that the recorders configuration is consistent at all times. The contents of the scratchpad memory can be discarded with the abort procedure. The scratchpad confirmation and abort procedures are described in the *Scratchpad Management* section.

The disturbance recorder configuration registers are in the range:

- 4x00600-4x00699

4.13.4 Protection Settings

Protection configuration-settings are written to a scratchpad memory area. A confirmation procedure is required to commit the contents of the scratchpad to the product's protection functions, which ensures that their configuration is consistent at all times. The contents of the scratchpad memory can be discarded with the abort procedure. The scratchpad confirmation and abort procedures are described in the *Scratchpad Management* section.

The product supports four groups of protection settings. One protection-group is active and the other three are either dormant or disabled. The active protection-group can be selected by writing to register 4x00404. An illegal data response is returned if an attempt is made to set the active group to one that has been disabled.

The MODBUS registers for each of the four groups are repeated in the following ranges:

- Group 1 4x01000-4x02999, (see note) 4x11000-4x12999
- Group 2 4x03000-4x04999, 4x13000-4x14999
- Group 3 4x05000-4x06999, 4x15000-4x16999
- Group 4 4x07000-4x08999, 4x17000-4x18999

Note	*Registers 4x02049 to 4x02052 are not part of protection setting group #1 so they do not repeat in any of the other protection setting groups. These registers are for time synchronization purposes and are standard for most Schneider Electric products. See the Time Synchronization section.*

4.13.5 Scratchpad Management

Register 4x00405 can be used to either confirm or abort the setting changes in the scratchpad area. In addition to the basic editing of the protection setting groups, these functions are provided:

- Default values can be restored to a setting group or to all of the product settings by writing to register 4x00402.
- It is possible to copy the contents of one setting group to another by writing the source group to register 4x00406 and the target group to 4x00407.
- The setting changes performed by either of these two operations are made to the scratchpad area. These changes must be confirmed by writing to register 4x00405.

4.14 Register Data Types

The product maps one or more MODBUS registers to data-typed information contained in an internal database. These data-types are referred to as G-Types since they have a 'G' prefixed identifier. The *Relay Menu Database document* gives a complete definition of the all of the G-Types used in the product.

Generally the data types are transmitted in high byte to low byte order, also known as "Big Endian format". This may require the MODBUS master to reorder the received bytes into a format that complies with its byte order and register order (for multi-register G-Types) conventions. Most MODBUS masters provide byte-swap and register-swap device (or data point) configuration to cope with the wide range of implementations.

The product's data types cannot be broken into smaller parts. Therefore multi-register data types cannot be read from or written to on an individual register basis. All of the registers for a multi-register data-typed item must be read from or written to with a single block read or write command. The following subsections provide some additional notes for a few of the more complex G-Types.

4.15 Numeric Setting (Data Types G2 & G35)

Numeric settings are integer representations of real (non-integer) values. The register value is the number of setting increments (or steps) that the real value is away from the real minimum value. This is expressed by this formula:

$S_{real} = S_{min.} + (S_{inc.} \times S_{numeric})$

Where:

S_{real}	Setting real value
$S_{min.}$	Setting real minimum value
$S_{inc.}$	Setting real increment (step) value
$S_{numeric}$	Setting numeric (register) value

For example, a setting with a real value setting range of 0.01 to 10 in steps of 0.01 would have the following numeric setting values:

Real value (S_{real})	Numeric value ($S_{numeric}$)
0.01	0
0.02	1
1.00	99

Table 15 - Numeric values

The G2 numeric data type uses 1 register as an unsigned 16-bit integer, whereas the G35 numeric data type uses 2 registers as an unsigned 32-bit integer. The G2 data type therefore provides a maximum setting range of $2^{16} \times S_{inc}$. Similarly the G35 data type provides a maximum setting range of $2^{32} \times S_{inc}$.

4.16 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 1 ms. The data-type is used for record time-stamps and for time synchronization (see the *Time Synchronization* section).

The structure of the data type is shown in the following table and complies with the IEC60870-5-4 Binary Time 2a format.

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	Y	=	0…99 Years (year of century)
I	=	0…59 minutes	R	=	Reserved bit = 0
H	=	0…23 Hours	SU	=	Summertime: 0=standard time, 1=summer time
W	=	1…7 Day of week; Monday to Sunday, 0 for not calculated	IV	=	Invalid value: 0=valid, 1=invalid
D	=	1…31 Day of Month			
M	=	1…12 Month of year; January to December	range	=	0ms…99 years

Table 16 - G12 date & time data type structure

The seven bytes of the structure are packed into four 16-bit registers. Two packing formats are provided: standard and reverse. The prevailing format is selected by the G238 setting in the **Date and Time** menu column or by register 4x306 (Modbus IEC Time).

The standard packing format is the default and complies with the IEC60870-5-4 requirement that byte 1 is transmitted first. This is 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 is in the high-order byte position followed by byte 2 in the low-order position for the first register. The last register contains just byte 7 in the high-order position and the low-order byte has a value of zero.

The reverse packing format is the exact byte transmission order reverse of the standard format. The null (zero) byte is sent as the high-order byte of the first register and byte 7 as the register’s low-order byte. The second register’s high-order byte contains byte 6 and byte 5 in its low order byte.

Both packing formats are fully documented in the *Relay Menu Database document* for the G12 type.

The principal application of the reverse format is for date-time packet format consistency when a mixture of MiCOM Px20, Px30, and Px40 series products are being used. This is especially true when there is a requirement for broadcast time synchronization with a mixture of such MiCOM products.

The data type provides only the value for the year of the century. The century must be deduced. The century could be imposed as 20 for applications not dealing with dates stored in this format from the previous (20th) century. Alternatively, the century can be calculated as the one that produces 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.

Note	*The value of the summertime bit does not affect the time displayed by the product.*

The day of the week field is optional and if not calculated is set to zero.

This data type (and therefore the product) does not cater for time zones so the end user must determine the time zone used by the product. UTC (universal co-ordinated time) is commonly used and avoids the complications of daylight saving timestamps.

4.17 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. The G125 format is preferred over the older G29 format.

4.17.1 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. Therefore the overall value conveyed by the G29 data type must be calculated as G29 = G28 × G27.

The product calculates the G28 per unit power or energy value as

G28 = ((measured secondary quantity) / (CT secondary) × (110 V / (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 saturates a long time before the equivalent G125.

The associated G27 multiplier is calculated as

G27 = (CT primary) × (VT primary / 110 V)
when primary value measurements are selected,
and as
G27 = (CT secondary) × (VT secondary / 110 V)
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.*

Example:

For A-Phase Power (Watts) (registers 3x00300 - 3x00302) for a 110 V nominal,
In = 1 A, VT ratio = 110 V:110 V and CT ratio = 1 A : 1 A.

Applying A-phase 1A @ 63.51V

A-phase Watts = ((63.51 V × 1 A) / In=1 A) × (110/Vn=110 V) = 63.51 Watts

The G28 part of the value is the truncated per unit quantity, which is equal to 64 (40h).

The multiplier is derived from the VT and CT ratios set in the product, with the equation ((CT Primary) × (VT Primary) / 110 V)). Therefore the G27 part of the value equals 1 and the overall value of the G29 register set is 64×1 = 64 W.

The registers would contain:

3x00300 - 0040h
3x00301 - 0000h
3x00302 - 0001h

Using the previous example with a VT ratio = 110,000 V:110 V and CT ratio = 10,000 A : 1 A the G27 multiplier would be 10,000 A × 110,000 V / 110 = 10,000,000. The overall value of the G29 register set is 64 × 10,000,000 = 640 MW. (Note that there is an actual error of 49 MW in this calculation due to loss of resolution).

The registers would contain:

3x00300 - 0040h
3x00301 - 0098h
3x00302 - 9680h

4.17.2 Data Type G125

Data type G125 is a short float IEEE754 floating point format, which occupies 32 bits in two consecutive registers. The most significant 16 bits of the format are in the first (low order) register and the least significant 16 bits in the second register.

The value of the G125 measurement is as accurate as the product's ability to resolve the measurement after it has applied the secondary or primary scaling factors as required. It does not suffer from the truncation errors or dynamic range limitations associated with the G29 data format.

5 IEC 60870-5-103 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.

These 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

5.1 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. If the fiber optic port is fitted, the active port can be selected using the front panel menu or the front Courier port. However the selection is only effective following the next relay power up.

For either of the two connection modes, both the relay address and baud rate can be selected using the front panel menu or the front Courier port. Following a change to either of these two settings a reset command is required to re-establish communications, see the description of the reset command in the *Initialization* section.

5.2 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 responds to either of the two reset commands (Reset CU or Reset FCB). However, the Reset CU clears any unsent messages in the relay’s transmit buffer.

The relay responds to the reset command with an identification message ASDU 5. The Cause Of Transmission (COT) of this response is either Reset CU or Reset FCB depending on the nature of the reset command. For information on the content of ASDU 5 see *section IEC60870-5-103 in the Relay Menu Database document*.

In addition to the ASDU 5 identification message, if the relay has been powered up it also produces a power-up event.

5.3 Time Synchronization

The relay time and date can be set using the time synchronization feature of the IEC60870-5-103 protocol. The relay corrects for the transmission delay as specified in IEC60870-5-103. If the time synchronization message is sent as a send / confirm message, the relay responds 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 is generated.

If the relay clock is synchronised using the IRIG-B input, it is not possible to set the relay time using the IEC60870-5-103 interface. If the time is set using the interface, the relay creates an event using the current date and time from the internal clock, which is synchronised to IRIG-B.

5.4 Spontaneous Events

Events are categorized using the following information:

- Function Type
- Information Number

The IEC60870-5-103 profile in the *Relay Menu Database document*, contains a complete listing of all events produced by the relay.

5.5 General Interrogation

The General Interrogation (GI) request can be used to read the status of the relay, the function numbers, and information numbers that are returned during the GI cycle. See the IEC60870-5-103 profile in the *Relay Menu Database document*.

5.6 Cyclic Measurements

The relay produces measured values using ASDU 9 cyclically. 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 or the front Courier port and is active immediately following a change.

The measurands transmitted by the relay are sent as a proportion of 2.4 times the rated value of the analog value.

5.7 Commands

A list of the supported commands is contained in the *Relay Menu Database document*. The relay responds to other commands with an ASDU 1, with a Cause of Transmission (COT) indicating ‘negative acknowledgement’.

5.8 Test Mode

Using either the front panel menu or the front Courier port, it is possible 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 is produced to indicate both entry to and exit from test mode. Spontaneous events and cyclic measured data transmitted while the relay is in test mode has a COT of ‘test mode’.

5.9 Disturbance Records

For Software Releases prior to B0 (i.e. 57 and earlier):

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.

For Software Release B0 - A & B:

The disturbance records are stored in uncompressed format and can be extracted using the standard mechanisms described in IEC60870-5-103. The Enhanced Disturbance Recorder software releases mean the relay can store a minimum of 15 records, each of 1.5 seconds duration.

Using relays with IEC 60870-5 CS 103 communication means they can store the same total record length. However, the IEC 60870-5 CS 103 communication protocol dictates that only 8 records (of 3 seconds duration) can be extracted via the rear port.

For Other Software Releases:

The disturbance records are stored in uncompressed format and can be extracted using the standard mechanisms described in IEC60870-5-103.

Where available, the Enhanced Disturbance Recorder software releases mean the relay can store a minimum of 15 records, each of 3.0 seconds duration.

Using relays with IEC 60870-5 CS 103 communication means they can store the same total record length. However, the IEC 60870-5 CS 103 communication protocol dictates that only 8 records (of 3 seconds duration) can be extracted via the rear port.

5.10 Blocking of Monitor Direction

The relay supports a facility to block messages in the Monitor direction and 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.

6 DNP3.0 INTERFACE

6.1 DNP3.0 Protocol

The DNP3.0 protocol is defined and administered by the DNP Users Group. For information on the user group, DNP3.0 in general and the protocol specifications, see www.dnp.org

The descriptions given there are intended to accompany the device profile document that is included in the *Relay Menu Database document.* 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 using 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 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).

6.2 DNP3.0 Menu Setting

The following settings are in the DNP3.0 menu 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
Time Sync.	Enabled, Disabled	Enables or disables the relay requesting time sync. from the master using IIN bit 4 word 1
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 is required.
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 length of time waited before requesting another time sync from the master.
DNP App Fragment	1 - 2048 bytes	The maximum message length (application fragment size) transmitted by the relay.
DNP App Timeout	1 -120 s	The length of time waited after sending a message fragment and waiting for a confirmation from the master.
DNP SBO Timeout	1 - 10 s	The length of time waited after receiving a select command and waiting for an operate confirmation from the master.
DNP Link Timeout	0 - 120 s	The length of time the relay waits 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 17 - G12 date & time data type structure

6.3 Object 1 Binary Inputs

Object 1, binary inputs, contains information describing the state of signals in 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. See the *Relay Menu Database document*. The binary input points can also be read as change events using object 2 and object 60 for class 1-3 event data.

6.4 Object 10 Binary Outputs

Object 10, binary outputs, contains commands that can be operated using DNP3.0. Therefore the points accept commands of type pulse on [null, trip, close] and latch on/off as detailed in the device profile in the *Relay Menu Database document* 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.

- If the Control Input DDB signal is already SET and a new DNP SET command is sent to the Control Input, the Control Input DDB signal goes momentarily to RESET and then back to SET.
- If the Control Input DDB signal is already RESET and a new DNP RESET command is sent to the Control Input, the Control Input DDB signal goes momentarily to SET and then back to RESET.

The following diagram shows the behavior when the Control Input is set to Pulsed or Latched.

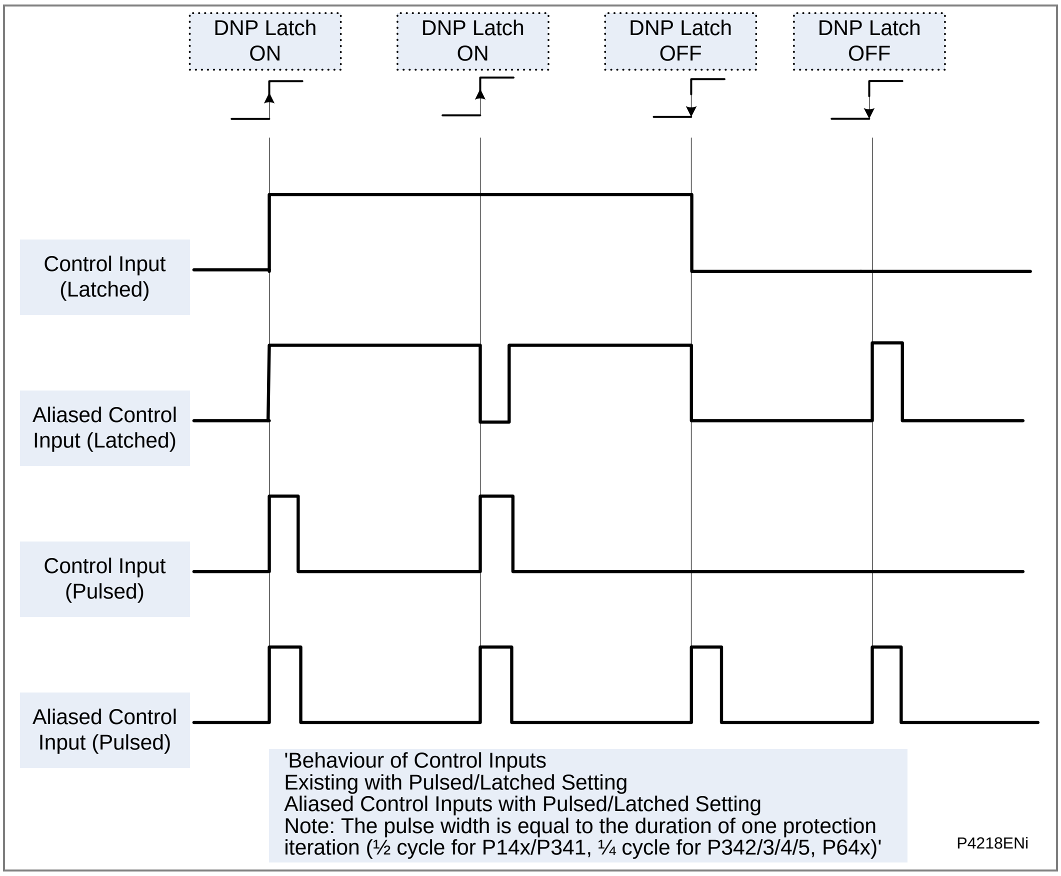


Figure 12 - Behavior of control inputs

Many of the relay's functions are configurable so some of the object 10 commands described in the following sections may not be available. A read from object 10 reports the point as off-line and an operate command to object 12 generates 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

6.5 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 whenever a freeze operation is performed and a change has occurred since the previous freeze command. The frozen counter event queues store the points for up to two freeze operations.

6.6 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 values 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 in 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 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 using Object 32 or Object 60. These events are generated for any point which has a value changed by more than the deadband setting since the last time the data value was reported.

Any analog measurement that is unavailable when it is read is reported as offline. For example, 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. All Object 30 points are reported as secondary values in DNP3.0 (with respect to CT and VT ratios).

Beside the measurements described above, the latest fault record can also be retrieved and mapped over DNP3.0 protocol in serial and Ethernet connections:

The fault data defined in Object 30 table are:

- Fault voltages, Fault currents and Fault Location
- Operating time of relay and Operating time of breaker
- Fault time, Fault data, etc.

6.7 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 such as current, voltage, and phase angle. All Object 40 points report the integer scaling values and Object 41 is available to configure integer scaling quantities.

6.8 DNP3.0 Configuration using MiCOM S1 Studio

A PC support package for DNP3.0 is available as part of MiCOM S1 Studio to allow configuration of the relay's DNP3.0 response. The PC is connected to the relay using a serial cable to the 9-pin connector on the front of the relay, see the *Introduction* chapter. 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. To restore the default configuration at any time, from the **Configuration** column, select the **Restore Defaults** cell then select **All Settings**.

In MiCOM S1 Studio, the DNP3.0 data is shown in three main folders, one folder each for the point configuration, integer scaling and default variation (data format). The point configuration also includes screens 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.

For the IP Configuration of DNP over Ethernet, please refer to section 6.8.1.

Important	**At most 10 clients are supported to connect to device at the same time in DNP3.0 over Ethernet protocol.**

6.8.1 DNP3.0 over Ethernet runs concurrently with IEC61850

DNP3.0 over Ethernet can run concurrently with IEC61850 if DNP3.0 over Ethernet plus IEC61850 option is chosen. Below table describes the different cases of the usage of DNP3.0 over Ethernet service and IEC61850 service. IEC61850 service will always run under this situation, but DNPoE service only runs when certain requirements are met.

Board Type	Dual or PRP/HSR	Configuration file	Interface 1		Interface 2		Invalid DNPoE IP Alarm
			IP address	DNP3oE	IP address	DNP3oE	
Q or R	Doesn't matter	Default IEC61850 configuration No DNP setting or IP_DNP is 0.0.0.0	DEF_IP_1	Disabled	DEF_IP_2	Disabled	No
	Dual	Default IEC61850 configuration	IP_DNP	Run	DEF_IP_2	N/A	No
	PRP/HSR	Customized DNP setting with valid IP_DNP	DEF_IP_1	N/A	IP_DNP	Run	No
	Doesn't matter	Customized IEC61850 configuration No DNPoE setting or IP_DNP is 0.0.0.0	IP_1	Disabled	IP_2	Disabled	No
	Doesn't matter	Customized IEC61850 configuration Customized DNPoE setting where IP_DNP = IP_1	IP_1	Run	IP_2	N/A	No
	Doesn't matter	Customized IEC61850 configuration Customized DNPoE setting where IP_DNP = IP_2	IP_1	N/A	IP_2	Run	No
	Doesn't matter	Customized IEC61850 configuration Customized DNPoE setting where IP_DNP ≠ IP_1 and IP_DNP ≠ IP_2	IP_1	Disabled	IP_2	Disabled	Yes
S	N/A	Default IEC61850 configuration No DNPoE setting or IP_DNP is 0.0.0.0	DEF_IP_1	Disabled	N/A	N/A	No
	N/A	Default IEC61850 configuration Customized DNPoE setting with valid IP_DNP	IP_DNP	Run	N/A	N/A	No
	N/A	Customized IEC61850 configuration No DNPoE setting or IP_DNP is 0.0.0.0	IP_1	Disabled	N/A	N/A	No
	N/A	Customized IEC61850 configuration Customized DNPoE setting where IP_DNP = IP_1	IP_1	Run	N/A	N/A	No
	N/A	Customized IEC61850 configuration Customized DNPoE setting where IP_DNP ≠ IP_1	IP_1	Disabled	N/A	N/A	Yes

Note *For detailed information about different interfaces please refer to the* ***Dual IP in MiCOM*** *section in the Dual Redundant Ethernet Board (DREB) chapter.*

Table 18 – Protocol running options for different board types

For these IP abbreviations please refer to this table:

Abbreviation	Description
DEF_IP_1	Default IP of interface 1 with default IEC61850 configuration
DEF_IP_2	Default IP of interface 2 with default IEC61850 configuration
IP_1	IP of interface 1 configured in a IEC61850 configuration file
IP_2	IP of interface 2 configured in a IEC61850 configuration file
IP_DNP	IP configured in DNP over Ethernet setting

Table 19 – Abbreviations of Different IP

Note *Running DNP3.0 serial and DNP3.0 over Ethernet concurrently is not recommended.*

7 IEC 61850 ETHERNET INTERFACE

7.1 Introduction

IEC 61850 is the international standard for Ethernet-based communication in substations. It enables integration of all protection, control, measurement and monitoring functions in a substation, and 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 Schneider Electric's 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.

7.2 What is IEC 61850?

IEC 61850 is a 14-part international standard, which defines a communication architecture for substations. It is more than just a protocol and provides:

- Standardized models for IEDs and other equipment in the substation
- Standardized communication services (the methods used to access and exchange data)
- Standardized formats for configuration files
- Peer-to-peer (for example, 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 tens 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.

7.2.1 Interoperability

A major benefit of IEC 61850 is interoperability. IEC 61850 standardizes the data model of substation IEDs which simplifies integration of different vendors’ products. Data is accessed in the same way in all IEDs, regardless of the vendor, even though the protection algorithms of different vendors’ relays may be different.

IEC 61850-compliant devices are not interchangeable, you cannot replace one device with another (although they are interoperable). However, the terminology is predefined and anyone with knowledge of IEC 61850 can quickly integrate a new device without mapping all of the new data. IEC 61850 improves substation communications and interoperability at a lower cost to the end user.

7.2.2 The 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.

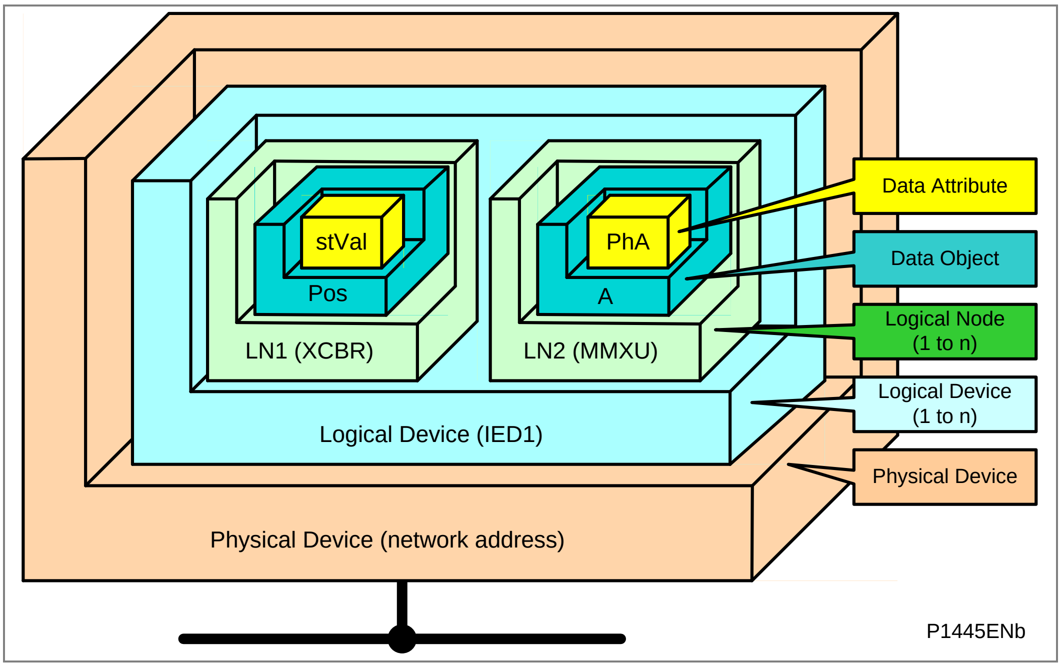


Figure 13 - Data model layers in IEC 61850

The levels of this hierarchy can be described as follows:

- Physical Device — Identifies the actual IED in 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 inthe Physical Device. For the MiCOM relays, five Logical Devices exist: **Control, Measurements, Protection, Records, System**.
- Wrapper/Logical Node Instance — Identifies the major functional areas in 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 presented. For example, **Pos** (position) of Logical Node type **XCBR**.
- Data Attribute — This is the actual data (such as measurement value, status, and description). For example, **stVal** (status value) indicates the actual position of the circuit breaker for Data Object type **Pos** of Logical Node type **XCBR**.

7.3 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.

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

7.3.1 Capability

The IEC 61850 interface provides these capabilities:

- 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.

  The following fault data have been mapped in LN RFLO1 of LD Records of IEC61850 data model for the latest fault record:

  - Fault voltages, Fault currents and Fault location
  - Operating time of relay and Operating time of breaker
  - Fault time, Fault date, etc…
- 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.
- GOOSE peer-to-peer communication
  GOOSE communications of statuses are included as part of the IEC 61850 implementation. See *Peer-to-Peer (GSE) Communications* for more details.
- Disturbance record extraction
  Disturbance records can be extracted from MiCOM relays by file transfer, as ASCII format COMTRADE files.
- Controls
  The following control services are available:
  - Direct Control
  - Direct Control with enhanced security
  - Select Before Operate (SBO) with enhanced security
  - Controls are applied to open and close circuit breakers using XCBR.Pos and DDB signals ‘Control Trip’ and ‘Control Close’.
  - System/LLN0. LLN0.LEDRs are used to reset any trip LED indications.
- 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 (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 (SYSTEM/LLN0).

- 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.
- Published GOOSE message
  Eight GOCBs are provided in SYSTEM/LLN0.
- Uniqueness of control
  The Uniqueness of control mechanism is implemented to be consistent 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.
- Select Active Setting Group
  Functional protection groups can be enabled or disabled using private mod/beh attributes in the 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'.
- 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 IEC61850 quality flags send quality attributes as all zeros. The supported quality attributes for outgoing GOOSE messages are described in the Protocol Implementation eXtra Information for Testing (PIXIT) document.
- Address List
  An Address List document (to be titled ADL) is produced for each IED which shows the mapping between the IEC61850 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.
- 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.

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, such as changes to protection settings, are done using MiCOM S1 Studio. These changes can also be done using the relay's front port serial connection or the relay's Ethernet link, and is known as "tunneling".

7.3.2 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 different 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 help this process, the MiCOM S1 Studio Support Software provides an IEC61850 IED Configurator tool. Select **Tools > IEC61850 IED Configurator**. This tool allows the preconfigured IEC 61850 configuration file (SCD or CID) to be imported and transferred to the IED. The configuration files for MiCOM relays can also be created manually, 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. The error checking ensures the configuration data is valid for sending to the IED and ensures the IED functions correctly in the substation.

To help 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.

7.3.2.1 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 in the inactive configuration bank, therefore not immediately affecting the current configuration. Both active and inactive configuration banks can be extracted at any time.

When the upgrade or maintenance stage is complete, the IED Configurator tool can be used to transmit a command to a single IED. This command authorizes 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 using 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.

7.3.2.2 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. If these parameters are not available using an SCL file, they must be configured manually.

If the assigned IP address is duplicated elsewhere on the same network, the remote communications do not operate in a fixed way. However, the relay checks for a conflict at power up and every time the IP configuration is changed. An alarm is raised if an IP conflict is detected.

Use the **Gateway** setting to configure the relay to accept data from networks other than the local network.

7.4 The Data Model of MiCOM Relays

The data model naming adopted in the Px30 and Px40 relays has been standardized for consistency. 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.

7.5 The 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.

7.6 Peer-to-Peer (GSE) Communications

The implementation of IEC 61850 Generic Object Oriented Substation Event (GOOSE) sets the way for cheaper and faster inter-relay communications. The generic substation event model provides fast and reliable system-wide distribution of input and output data values. The generic substation event model is based on autonomous decentralization This provides an efficient method of allowing simultaneous delivery of the same generic substation event information to more than one physical device, by using 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 (sends) a new message. Any device that is interested in the information subscribes (listens) to the data message.

*Note**	*Multicast messages cannot be routed across networks without specialized equipment.*

Each new message is retransmitted at user-configurable intervals until the maximum interval is reached, 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 GOOSE schemes before or during commissioning; in just the same way a hardwired scheme must be tested.

7.6.1 Scope

A maximum of 32 virtual inputs are available in the PSL which can be mapped directly to a published dataset in a GOOSE message (only 1 fixed dataset is supported). All published GOOSE signals are BOOLEAN values.

Each GOOSE signal contained in a subscribed GOOSE message can be mapped to any of the 32 virtual inputs in 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 these data types can be decoded and mapped to a virtual input:

- BOOLEAN
- BSTR2
- INT16
- INT32
- INT8
- UINT16
- UINT32
- UINT8

7.6.2 Simulation GOOSE Configuration

From MiCOM S1 Studio select Tools > IEC 61850 IED Configurator (Ed.2). Make sure the configuration is correct as this ensures efficient GOOSE scheme operation.

The relay can be set to publish/subscribe simulation/test GOOSE; it is important that this setting is returned to publish/receive normal GOOSE messages after testing to permit normal operation of the application and GOOSE messaging.

The relay provides a single setting to receive Simulated GOOSE, however it manages each subscribed GOOSE signal independently when the setting is set to simulated GOOSE. Each subscription (virtual input) will continue to respond to GOOSE messages without the simulation flag set; however once the relay receives a GOOSE for a subscription with the simulation flag set, it will respond to this and ignore messages without the simulation flag set. Other subscriptions (virtual inputs) which have not received a GOOSE message with the simulation flag will continue to operate as before. When the setting is reset back to normal GOOSE messaging the relay will ignore all GOOSE messages with the simulation flag set and act on GOOSE messages without the simulation flag.

WARNING **If you set the GOOSE in Simulation Mode, you MUST set it back to normal GOOSE after testing.**
IT IS POTENTIALLY EXTREMELY UNSAFE TO ATTEMPT TO USE ANY RELAY WHICH IS STILL IN GOOSE SIMULATION MODE.

7.6.3 High Performance GOOSE

In addition, the Px40 device is designed to provide maximum performance through an optimized publishing mechanism. This optimized mechanism is enabled so that the published GOOSE message is mapped using only the data attributes rather than mapping a complete data object. If data objects are mapped, the GOOSE messaging will operate correctly; but without the benefit of the optimized mechanism.

A pre-configured dataset named as "HighPerformGOOSE" is available in Ed.2 ICD template, which include all data attributes of all virtual outputs. We recommend using this dataset to get the benefit of better GOOSE performance. The optimized mechanism also applies to Ed.1 but without such a pre-configured dataset.

7.7 Ethernet Functionality

Settings relating to a failed Ethernet link are available in the ‘COMMUNICATIONS’ column of the relay user interface.

7.7.1 Ethernet Disconnection

IEC 61850 'Associations' are unique and made to the relay between the client (master) and server (IEC 61850 device). If the Ethernet is disconnected, such associations are lost and must 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.

7.7.2 Redundant Ethernet Communication Ports (optional)

For information regarding the Redundant Ethernet communication ports, refer to the stand alone document *Px4x/EN REB/B11*.

7.7.3 Loss of Power

If the relay's power is removed, the relay allows the client to re-establish associations without a negative impact on the relay's operation. As the relay acts as a server in this process, the client must request the association. Uncommitted settings are cancelled when power is lost. Reports requested by connected clients are reset and must be re-enabled by the client when the client next creates the new association to the relay.

7.7.4 Courier Tunneling via Secure Ethernet Communications

7.7.4.1 Introduction

When the IED and Easergy Studio (MiCOM S1 Studio) are connected via the Ethernet port they will communicate securely using TLS.
The benefits of secure communication are:

- Help in the prevention of unwanted eavesdropping between Easergy Studio (MiCOM S1 Studio) and the IED
- Help in the prevention of modification of data between Easergy Studio (MiCOM S1 Studio) and the IED
- Ensure integrity of data
- Prevent replay of data at a later data

Note	*The communication will be done using port 4422, ensure this port is left unblocked on your network.*

7.7.4.2 Setting up a Connection

As a quick guide you need to do the following:

1. In Easergy Studio(MiCOM S1 Studio), click the Quick Connect… button
2. Select the relevant Device Type in the Quick Connect dialog box.
3. Select Ethernet port
4. Enter the relevant data i.e. IP address of IED
5. Click Finish
6. Easergy Studio (MiCOM S1 Studio) will attempt to communicate with the device

Note	*When attempting to connect to the IED via Ethernet Easergy Studio (MiCOM S1 Studio) will first attempt to communicate with the IED via secure communication if this is not possible it will use open communication with no encryption.* *For secure communication please ensure port 4422 is left unblocked on the firewalls on which Easergy Studio (MiCOM S1 Studio) is running.*

INSTALLATION

CHAPTER 16

Date (month/year):	11/2016			
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:	P141/P142/P143	J/L	P44y (P443/P446)	K/M
	P145	J/M	P547	K
	P241	J	P54x (P543/P544/P545/P546)	K/M
	P242/P243	K	P642	J/L
	P342	J	P643	K/M
	P343/P344/P345	K	P645	K/M
	P391	A	P74x (P741/P742/P743)	J/K
	P445	J/L	P746	K/M
	P44x (P441/P442/P444)	J/K	P841	K/M
	P44x (P442/P444)	M	P849	K/M
Software version:	P14x (P141/P142/P143/P145)	43/44/46/ B0/B1/B2	P44y (P443/P446) P547	55/H4 57
	P24x (P241/P242/P243):	57	P54x (P543/P544/P545/P546)	45/55/H4
	P342/P343/P344/P345/P391	36	P64x (P642/P643/P645)	04/A0/B1/B2
	P445	35/36/J4	P74x (P741/P742/P743)	51/A0/B1
	P44x (P441/P442/P444)	C7.x/D4.x/ D5.x/D6.x/	P746	A0/B1/B2/B3/ C1/C2/C3
	P44x (P442/P444)	E0/E1	P841 P849	45/55/G4/H4 A0/B1
Connection diagrams:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 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) P44x (P441, P442 & P444): 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2)		P54x (P543, P544, P545 & P546): 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) P547: 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P74x (P741, P742 & P743): 10P740xx (xx = 01 to 07) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)	

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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
- **P445** Full scheme **Distance Protection** relays for MV, HV and EHV systems
- **P44x** Full scheme **Distance Protection** relays for MV, HV and EHV systems
- **P44y** 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
- **P547** **Line Differential** protection relays for HV/EHV systems with multiple communication options and phase comparison protection for use with PLC
- **P64x** **Transformer Protection Relays**
- **P74x** **Numerical Busbar Protection** for use on MV, HV and EHV busbars
- **P746** **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. See the *Storage* section for 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/5L M/L11 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 electronic circuits inside the relay 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.
The old GN0037/GN0038 part numbers are now obsolete.
They have been replaced by the GN0242/GN0243 versions as shown below.

Product	Size	Part No (obsolete)	Replacement Part No
P40	**40TE** **60TE / 80TE**	**GN0037 001** **GN0038 001**	**GN0242 001** **GN0243 001**
P14x	40TE 60TE / 80TE	GN0037 001 GN0038 001	GN0242 001 GN0243 001
P24xxxxxxxxxxxA P24xxxxxxxxxxxC	40TE 60TE / 80TE	GN0037 001 GN0038 001	GN0242 001 GN0243 001
P24xxxxxxxxxxxJ P24xxxxxxxxxxxK	40TE 60TE / 80TE		GN0242 001 GN0243 001
P34xxxxxxxxxxxA P34xxxxxxxxxxxC	40TE 60TE / 80TE	GN0037 001 GN0038 001	GN0242 001 GN0243 001
P34xxxxxxxxxxxJ P34xxxxxxxxxxxK	40TE 60TE / 80TE		GN0242 001 GN0243 001
P44x	40TE 60TE / 80TE	GN0037 001 GN0038 001	GN0242 001 GN0243 001
P44y	60TE / 80TE	GN0038 001	GN0243 001
P445	40TE 60TE / 80TE	GN0037 001 GN0038 001	GN0242 001 GN0243 001
P54x	60TE / 80TE	GN0038 001	GN0243 001
P547	60TE / 80TE	GN0038 001	GN0243 001
P64xxxxxxxxxxxA/B/C	40TE 60TE / 80TE	GN0037 001 GN0038 001	GN0242 001 GN0243 001
P64xxxxxxxxxxxJ/K	40TE 60TE / 80TE		GN0242 001 GN0243 001
P74x P74x	40TE 60TE	GN0037 001 GN0038 001	GN0242 001 GN0243 001
P746	80TE	GN0038 001	GN0243 001
P841	60TE / 80TE	GN0038 001	GN0243 001
P849	80TE	GN0038 001	GN0243 001

Note *Part Numbers suitable for rack-mounting have an "N" as the 10^{th} digit.*
Part Numbers suitable for panel-mounting have an "M" as the 10^{th} digit.
Size 40TE may be GN0242 001 and 60TE/80TE as GN0243 001.

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 MiCOM P991 or Easergy test block is to be included with the relays, we recommend 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.

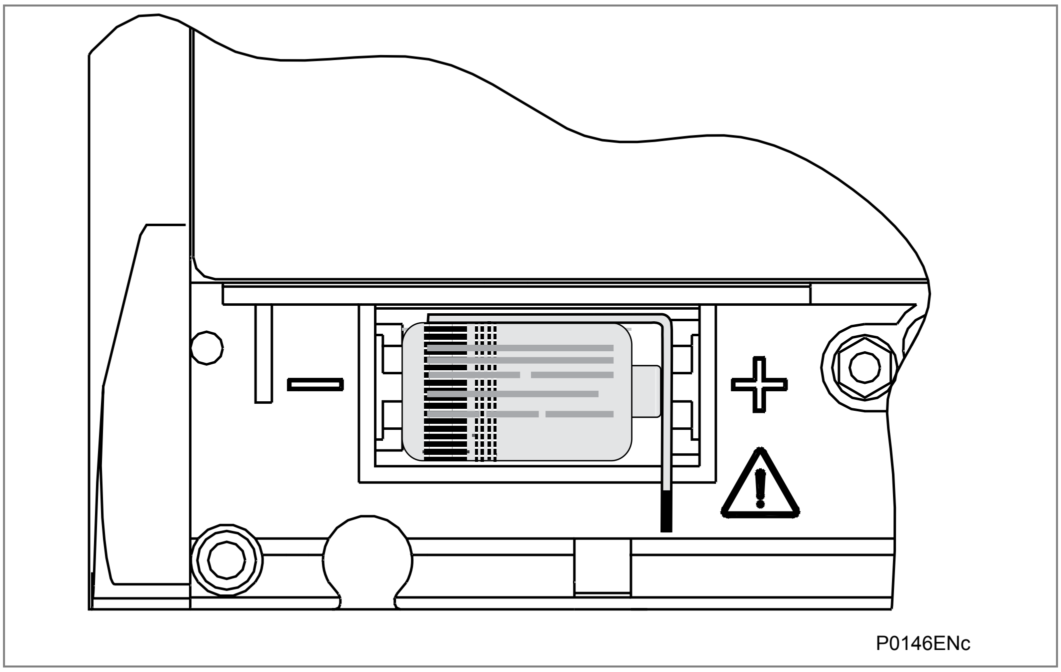


Figure 1 - Location of battery isolation strip

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 the *Location of battery isolation strip* diagram, i.e. with the strip behind the battery with the red tab protruding.

3.1 Rack Mounting

Virtually all MiCOM relays can be rack mounted using single tier rack frames (part number FX0021 101), see the ***Rack mounting of relays*** diagram below. 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).

Warning	**Risk of damage to the front cover moulding. Do not use conventional self-tapping screws, including those supplied for mounting other 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.

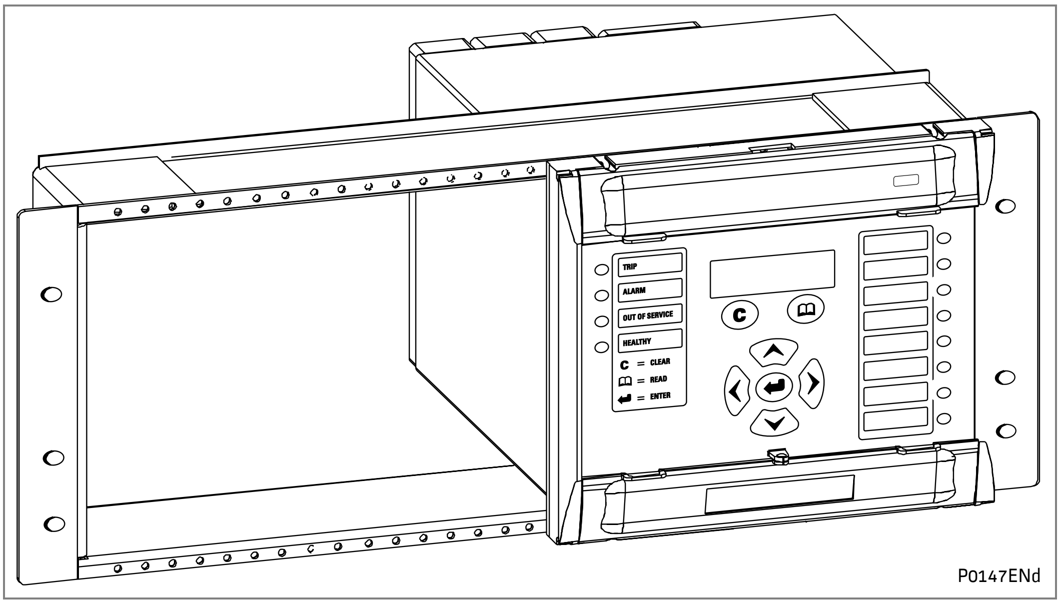


Figure 2 - Rack mounting of relays

Relays can be mechanically grouped into single tier (4U) or multi-tier arrangements by the rack frame. This enables schemes using MiCOM products 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. The following ***Blanking plates*** table shows the sizes that can be ordered.

Note *Blanking plates are only available in grey.*

Case size summation	Blanking plate part number
10TE	GJ2028 102
20TE	GJ2028 104
30TE	GJ2028 106
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).

Warning **Risk of damage to the front cover moulding. Do not use conventional self-tapping screws, including those supplied for mounting other relays because they have slightly larger heads.**

Alternatively tapped holes can be used if the panel has a minimum thickness of 2.5 mm. 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 the following ***IP52 sealing rings*** table around the complete assembly.

Width	Single tier	Double tier
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

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/5L M/L11 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 “C”,“D”,“E” or “F” prefix (depending on the relay)

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 the *M4 90° crimp ring terminals* table). 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 maximum 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 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

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 switches are located in the same cubicle.

The connector for the Ethernet port is a shielded RJ-45. The following ***Signals on the Ethernet connector*** table 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-called "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 protocol. 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 - Pin connections for IEC 60870-5-2 over EIA(RS)232/574

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 - Pin connections for K-bus or IEC 60870-5-2 over EIA(RS)485

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

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/5L M/L11 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 Easergy or P99x test blocks. Both Easergy 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 the ***Medium and Heavy Duty Terminal Block Connections*** section.

Caution	**Wiring between the DC rotor winding and the P391 must 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 here:

Range	Case Size		
	40TE	60TE	80TE
P14x	P141, P142	P143, P145	P143
P24x	P241	P242	P243
P34x	P341, P342	P341, P342, P343	P343, P344, P345
P441	P441		
P44x		P442	P444
P44y			P443, P446
P445	P445	P445	
P541	P541		
P542		P542	
P54x		P543, P544	P545, P546
P547			P547
P64x	P642	P643, P645	P645
P74x	P742	P743	P741
P746			P746
P841		P841	P841
P849			P849

Table 8 - Products and case sizes

5.1 40TE Case Dimensions

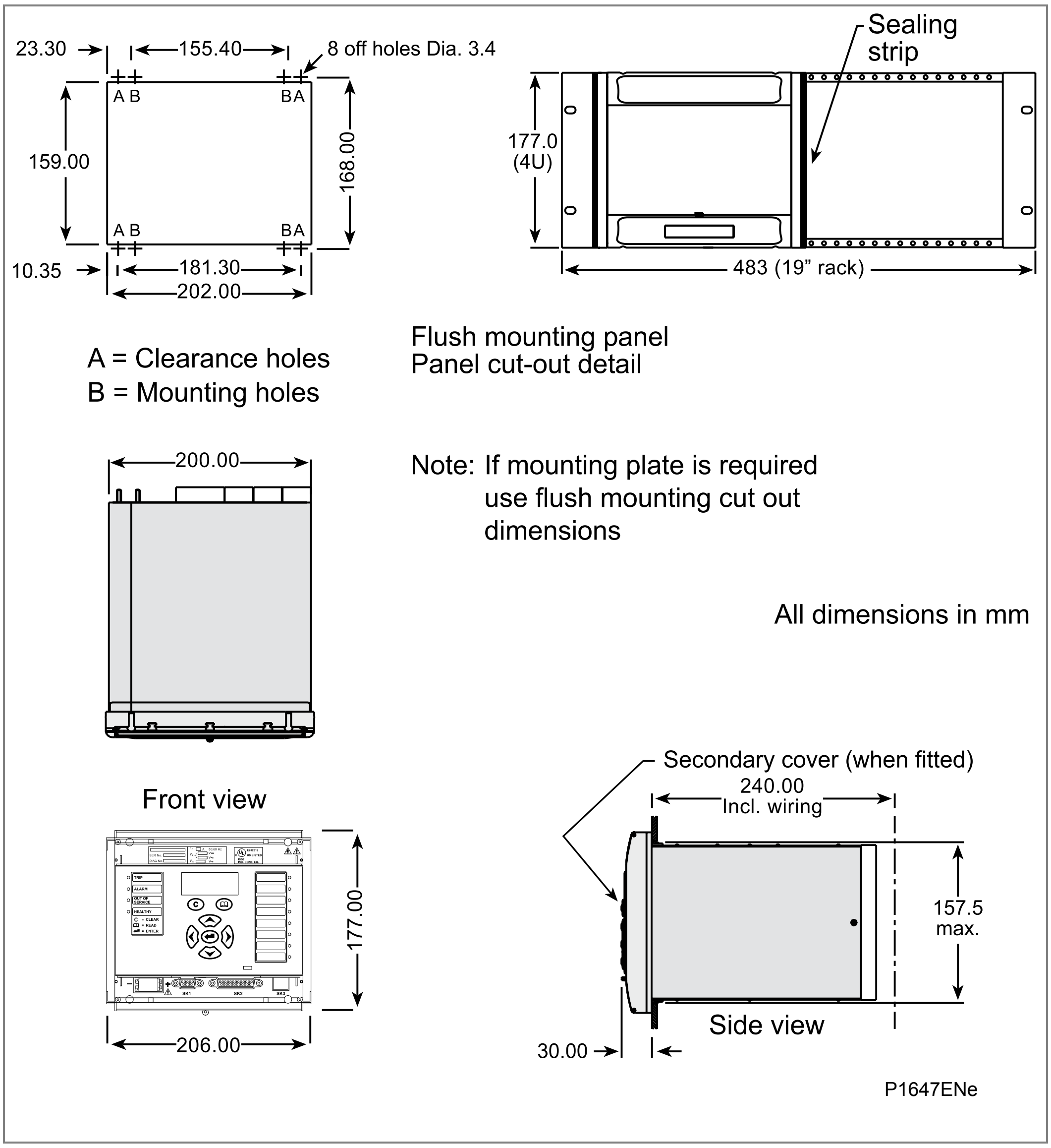


Figure 3 - 40TE Case Dimensions

5.2 60TE Case Dimensions

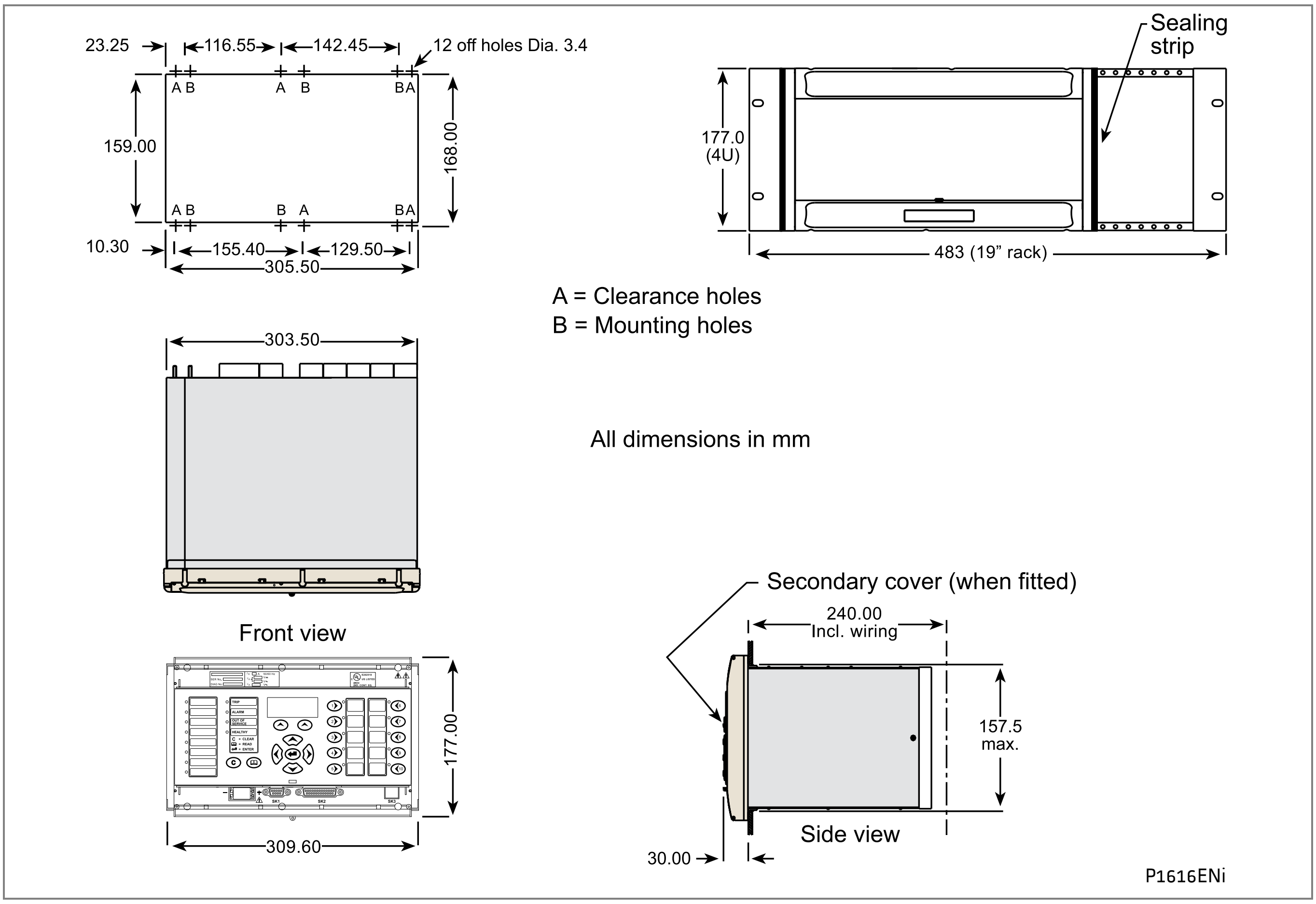


Figure 4 - 60TE Case Dimensions

5.3 80TE Case Dimensions

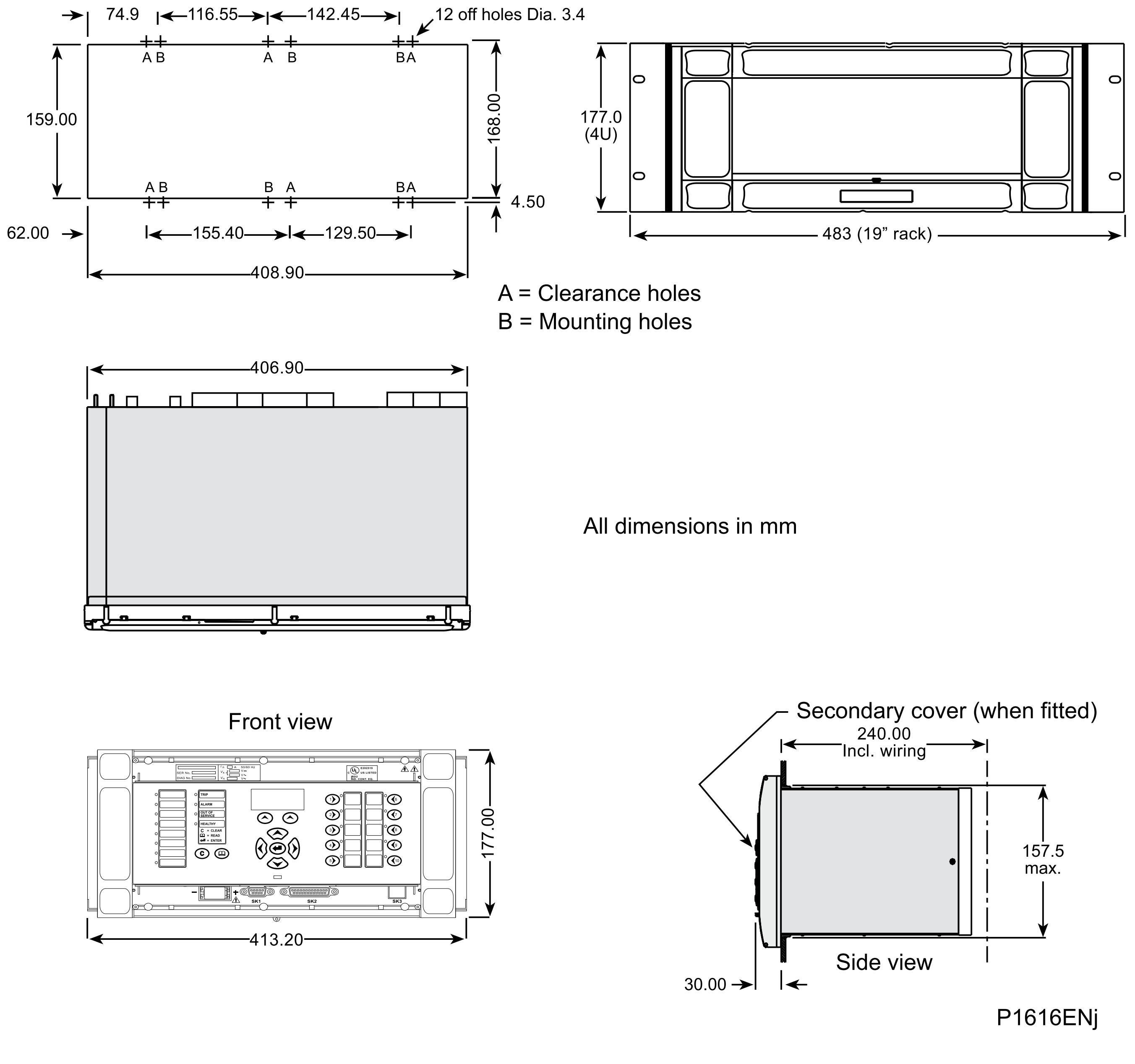


Figure 5 - 80TE Case Dimensions

CONNECTION DIAGRAMS

CHAPTER 17

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

CONTENTS

TABLES

FIGURES

1 P391 ROTOR EARTH FAULT UNIT (REFU) MOUNTING

The P391 unit is dispatched either individually or as part of a panel/rack/wall assembly.

Sufficient airflow must be maintained around the P391 at all times. For this reason it is essential that a minimum clearance from other equipment of 2U (89 mm) above and 1U (44.5 mm) below the P391 is maintained.

The Rotor Earth Fault Unit (REFU) is normally supplied with an outline diagram showing the dimensions for panel cut-outs and hole centers. This information can also be found in the product publication.

1.1 Rack Mounting

The P391 unit can be rack mounted into a rack with M6 x16 slotted pan head screws provided.

1.2 Panel Mounting

The P391 unit can be flush mounted into panels using M4 x 8 Pan head Taptite self-tapping screws provided. These fastenings are available in packs of 5 (Schneider Electric part number ZA0005 104).

Alternatively tapped holes can be used if the panel has a minimum thickness of 2.5 mm.

1.3 Wall Mounting

The P391 unit can be wall mounted using M6 anchor bolts or similar (not provided).

2 P391 ROTOR EARTH FAULT UNIT (REFU) MOUNTING

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.**

2.1 Medium Duty Terminal Block Connections

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 1). Each type is available in bags of 100.

Part number	Wire size	Insulation color
ZB9124 901	0.25 – 1.65 mm^2 (22 - 16 AWG)	Red
ZB9124 900	1.04 – 2.63 mm^2 (16 - 14 AWG)	Blue
ZB9124 904	2.53 – 6.64 mm^2 (12 - 10 AWG)	Uninsulated*
**Note*	*To maintain the terminal block insulation requirements for safety, an insulating sleeve should be fitted over the ring terminal after crimping.*	

Table 1 - M4 90° crimp ring terminals

The following minimum wire sizes are recommended:

Auxiliary Supply, Vx	1.5 mm^2
Rotor winding to P391	1.0 mm^2
Other Circuits	1.0 mm^2

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. If a larger wire size is required, two wires can be used in parallel, each terminated in a separate pre-insulated 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.

2.2 Current Loop Input Output (CLIO) Connections (if applicable)

A current loop output is available on the P391 relay, the connections are made using screw clamp connectors, 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, connection of the screen is discussed in the following sections. The wire should have a minimum voltage rating of 300 Vrms.

2.3 Protective Conductor (Earth) Connection (PCT)

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 2.5 mm^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 the PCT is 6.0 mm^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.

As DC currents of up to 29 mA will appear in the earth circuit under rotor earth fault conditions, the P391 shall be permanently connected to the local earth via the protective conductor terminal provided.

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.*

3 PX4X COMMUNICATION OPTIONS

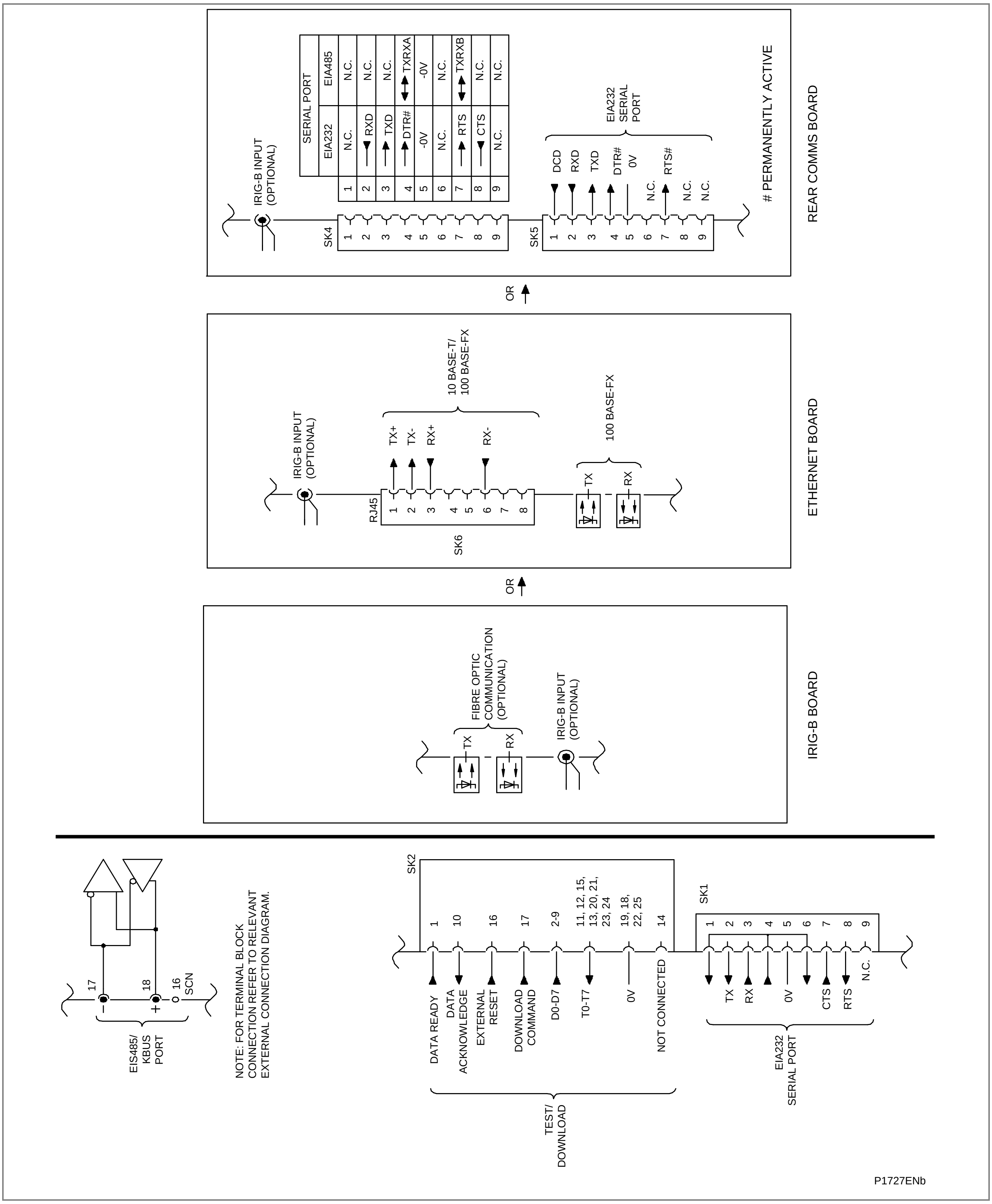


Figure 1 – Communication options Px40 platform

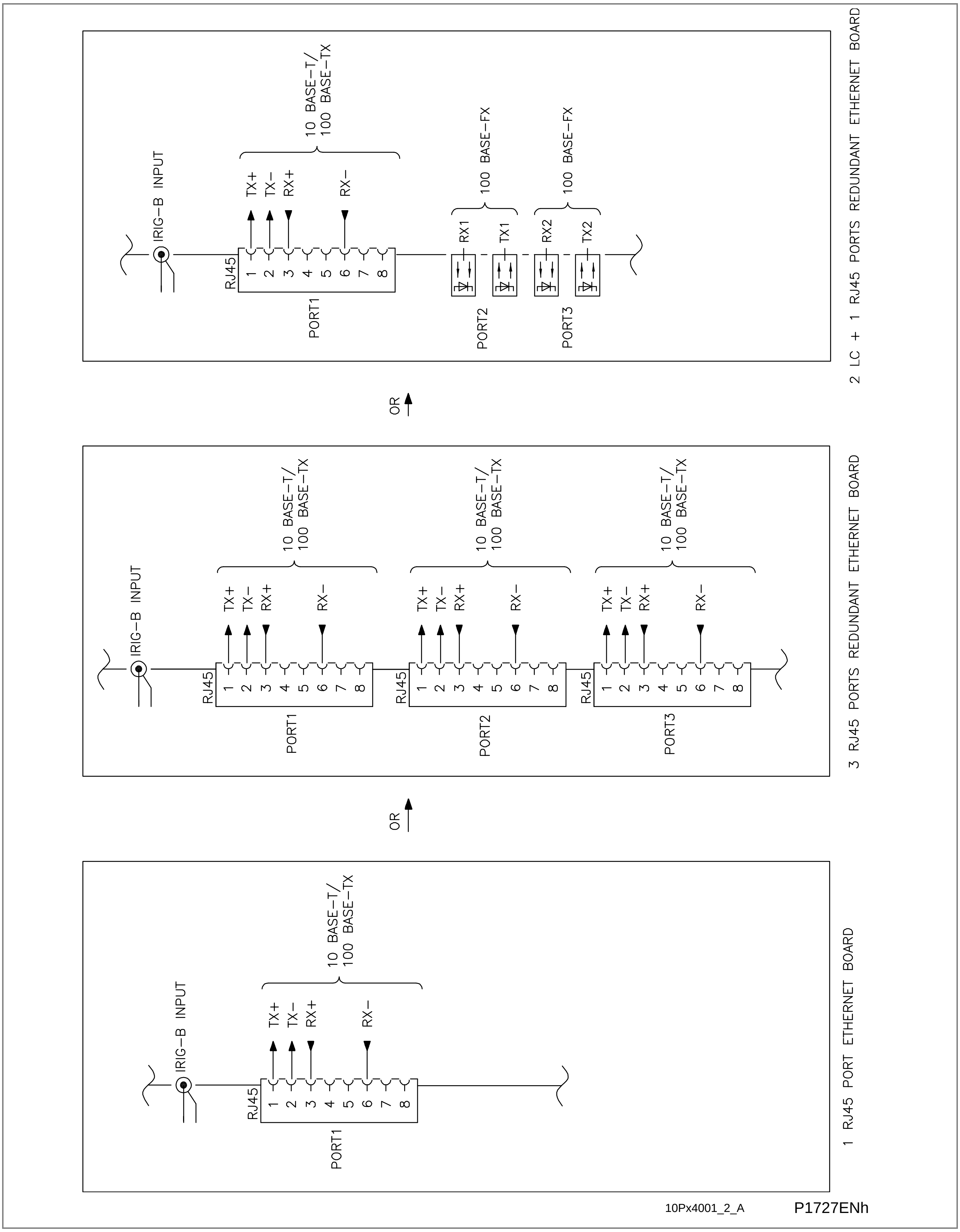


Figure 2 - External Communications Options MiCOM Px40 platform

Notes:

4 P391 CONNECTION DIAGRAMS

This section includes the following drawings:

- Figure 3 - P391 outline and panel mounting details (80TE case)
- Figure 4 - P391 outline and rack mounting details (80TE case)
- Figure 5 - P391 outline and wall mounting details (80TE case)
- Figure 6 - P391 Rotor Earth Fault double ended field winding connection
- Figure 7 - P391 Rotor Earth Fault single ended field winding connection

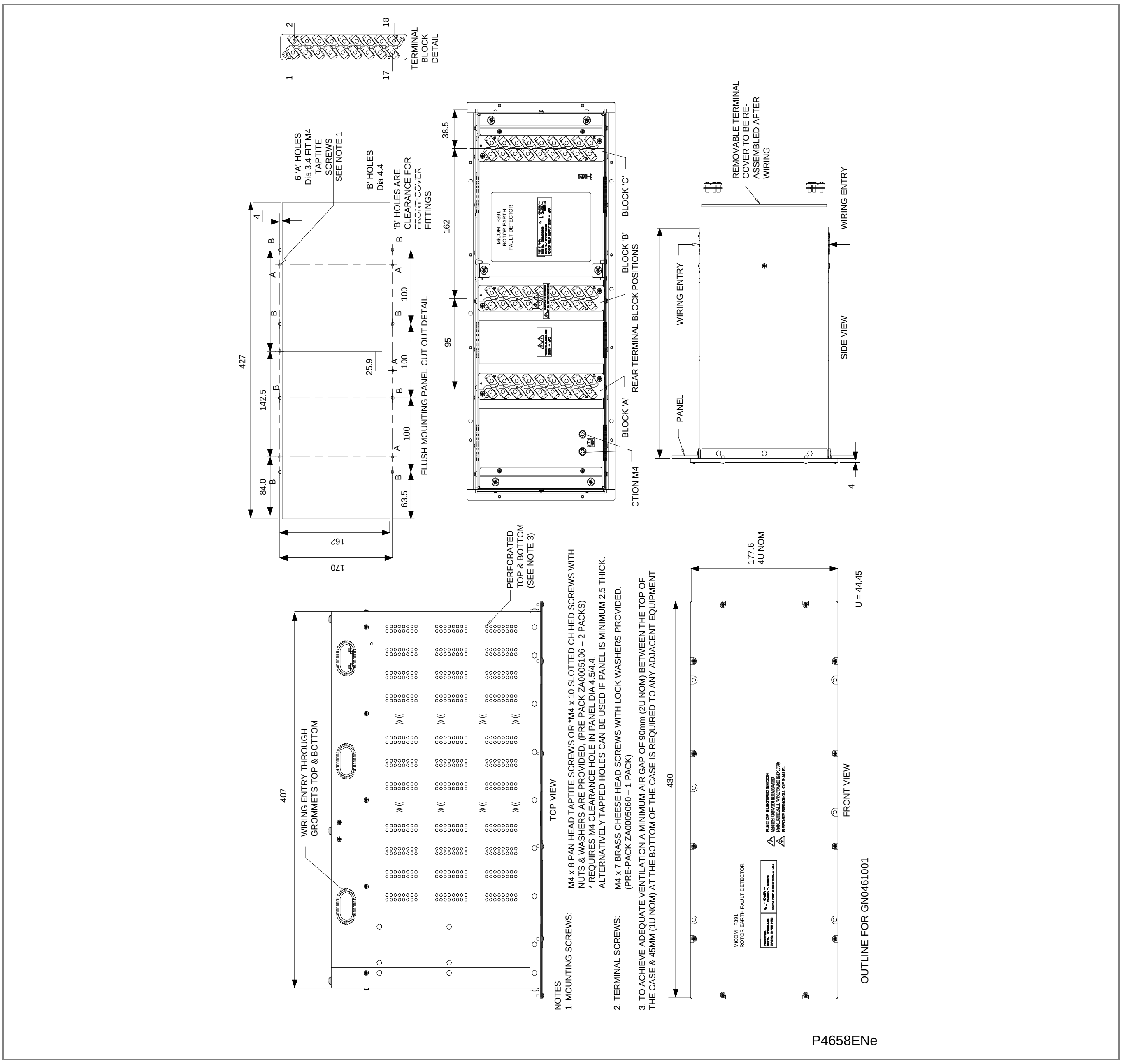


Figure 3 - P391 outline and panel mounting details (80TE case)

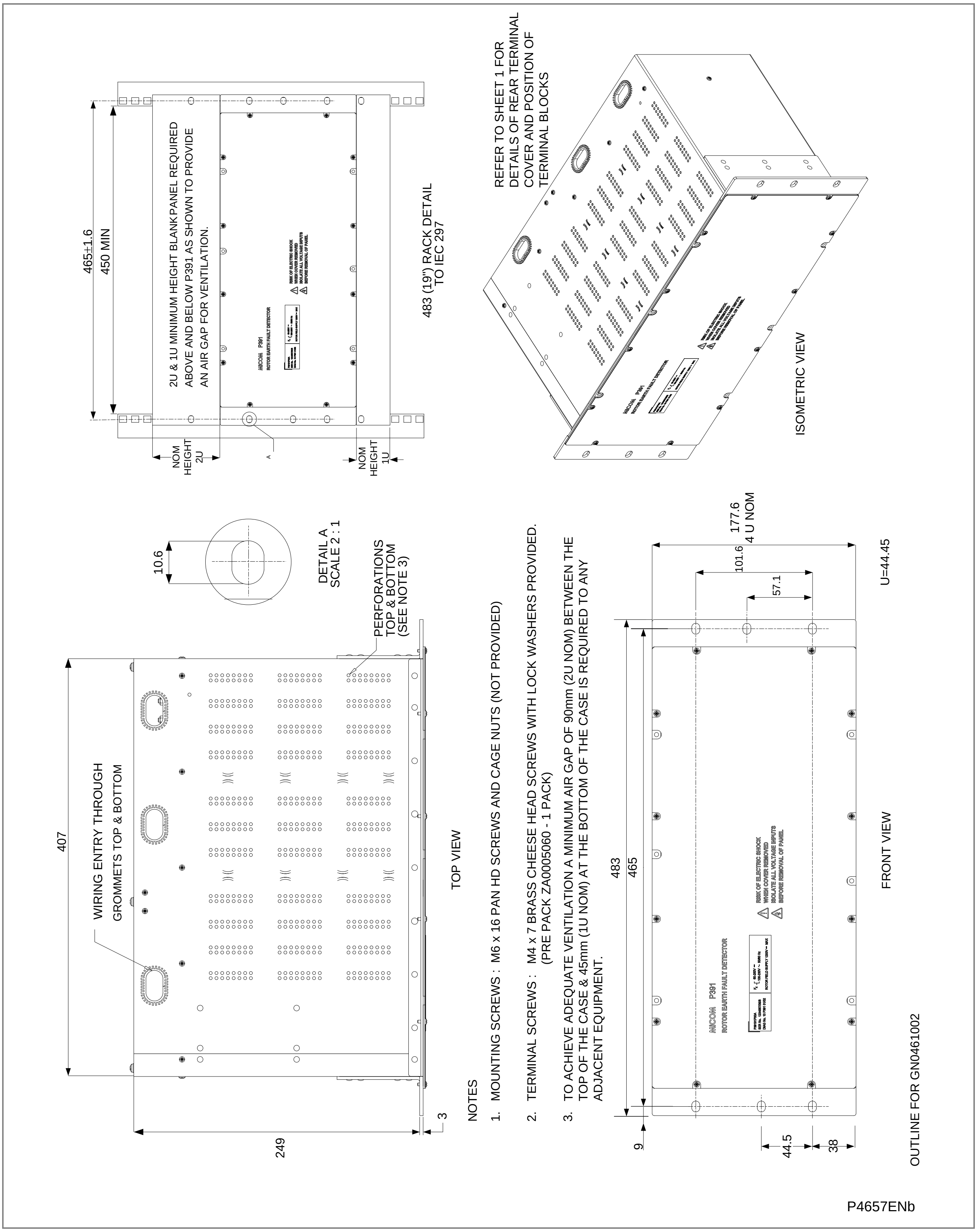


Figure 4 - P391 outline and rack mounting details (80TE case)

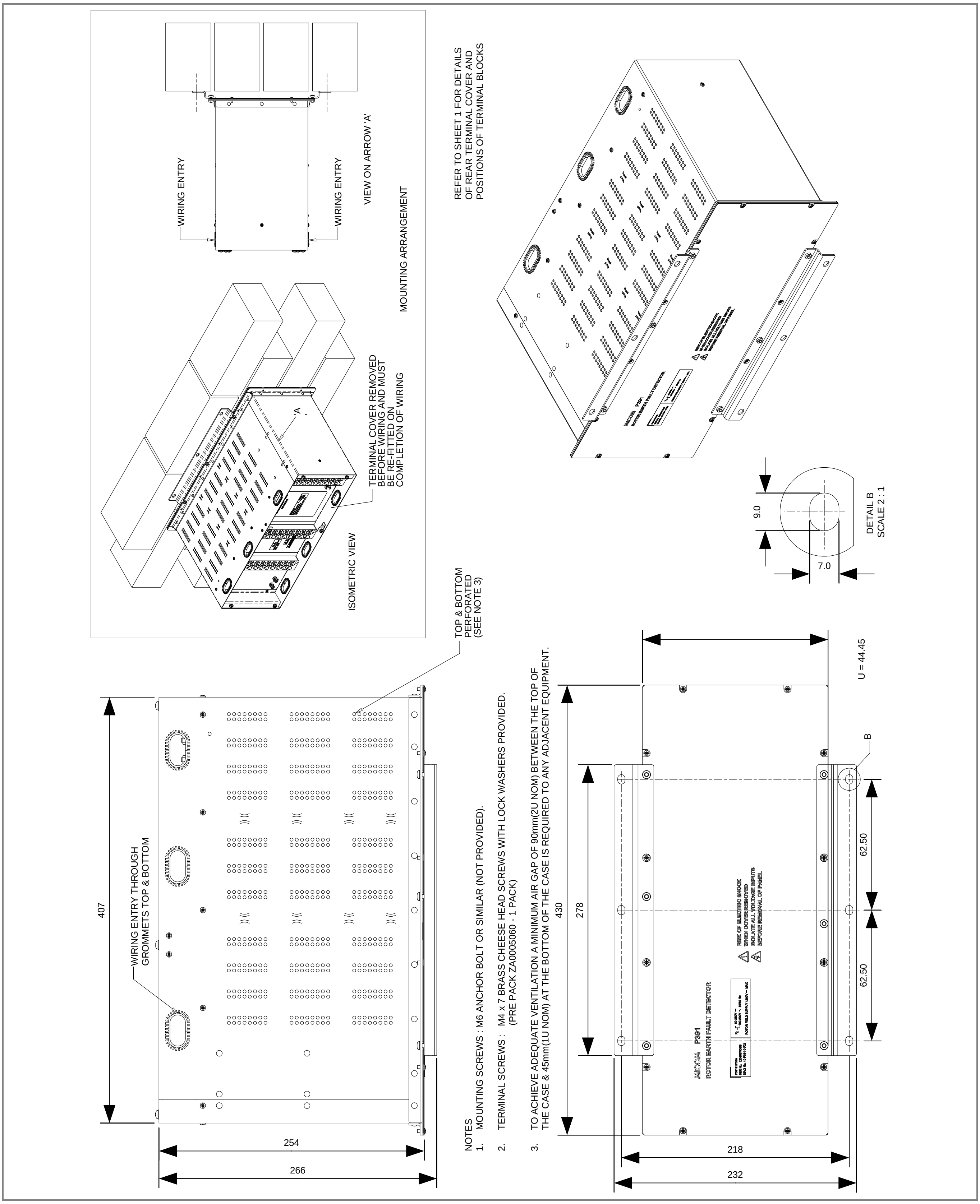


Figure 5 - P391 outline and wall mounting details (80TE case)

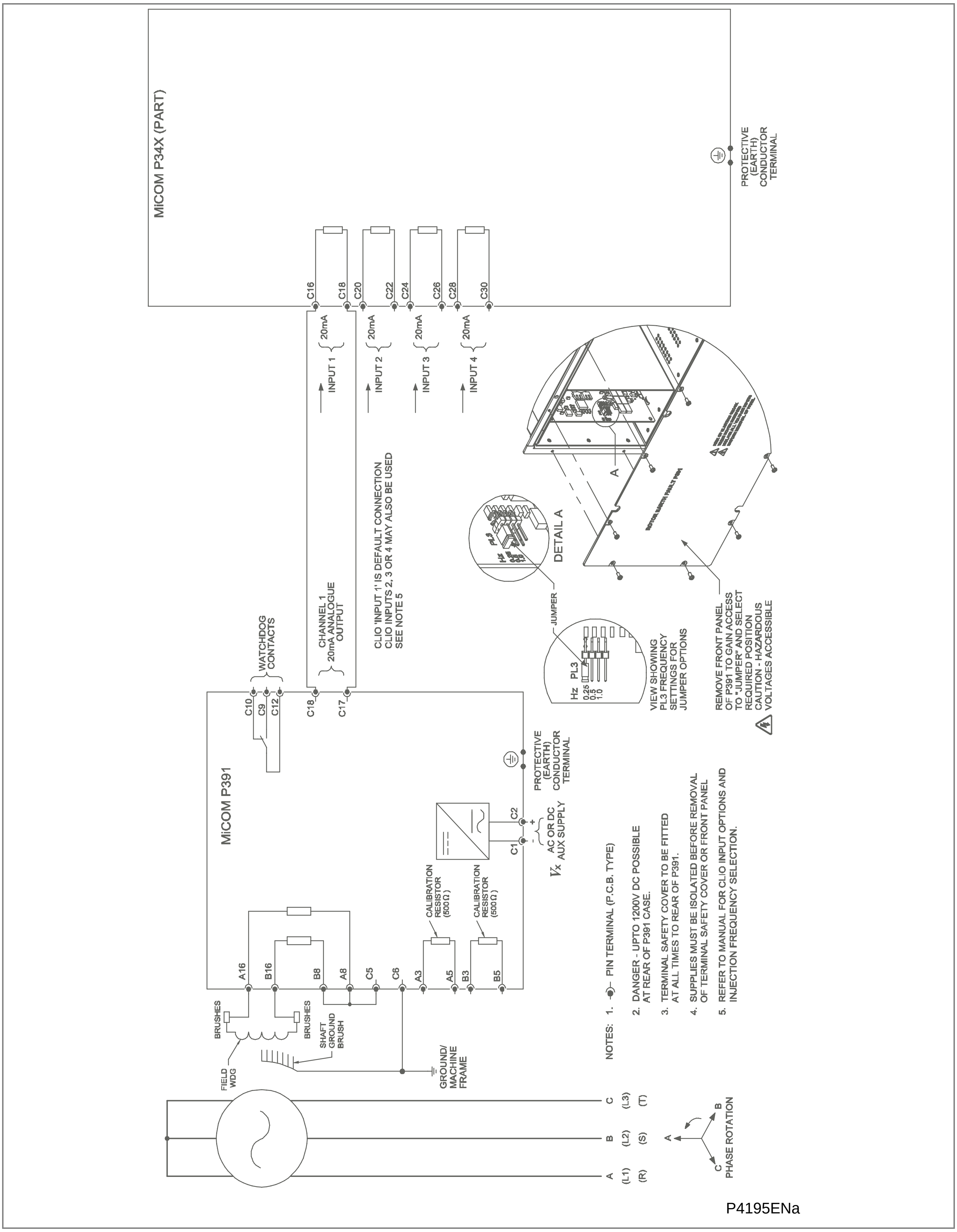


Figure 6 - P391 Rotor Earth Fault double ended field winding connection

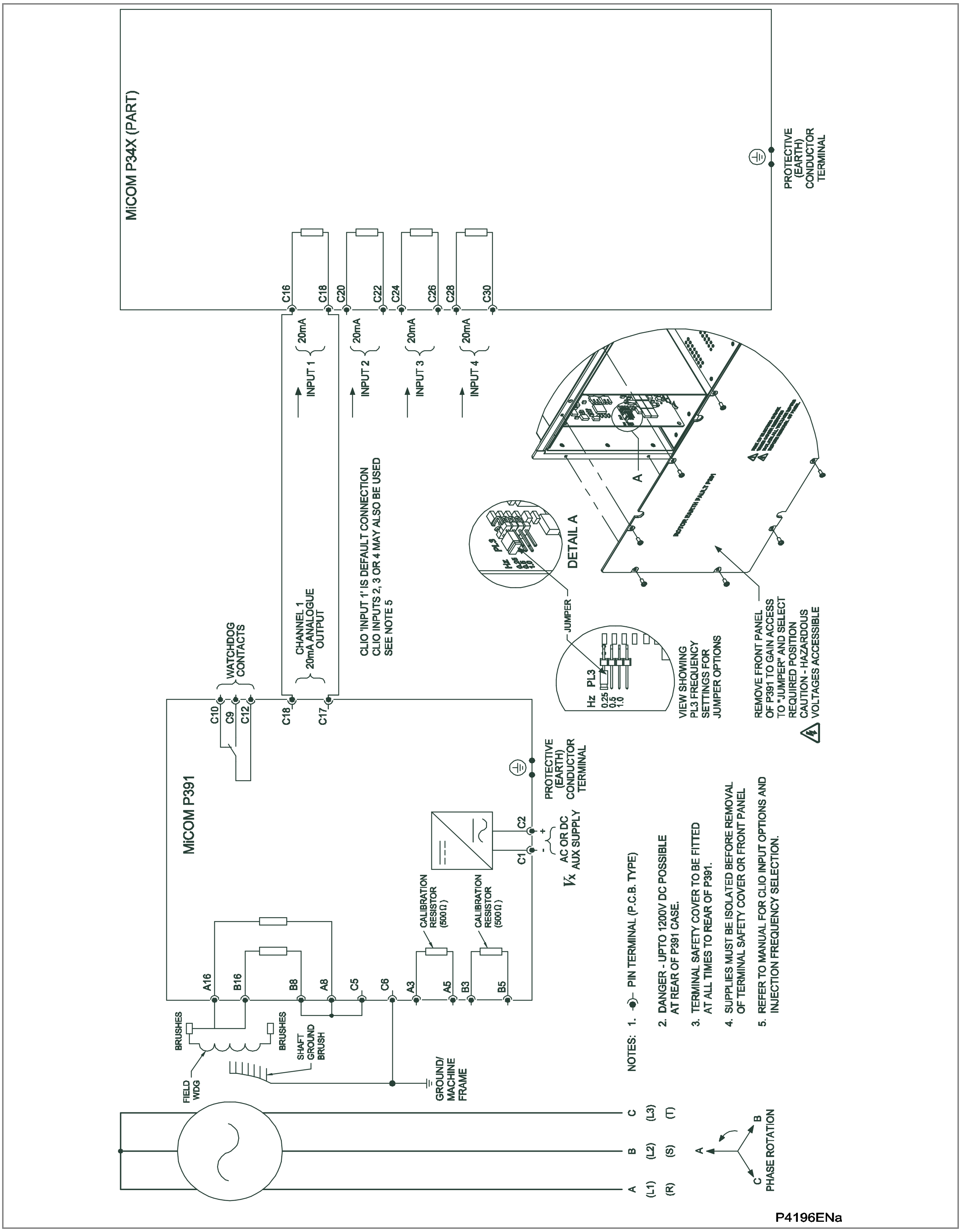


Figure 7 - P391 Rotor Earth Fault single ended field winding connection

Notes:

1 P342 CONNECTION DIAGRAMS

This section includes the following diagrams:

- Figure 8 - P342 (40TE) for small generator using VEE connected VT's (8 I/P & 7 O/P)
- Figure 9 - P342 (40TE) for small generator with sensitive power (8 I/P & 7 O/P)
- Figure 10 - P342 (40TE) for small generator with check synch (8 I/P & 7 O/P)
- Figure 11 - P342 (40TE) for small generator (8 I/P & 7 O/P & RTD's)
- Figure 12 - P342 (40TE) for small generator (8 I/P & 7 O/P & CLIO)
- Figure 13 - P342 (40TE) for small generator (8 I/P & 15 O/P)
- Figure 14 - P342 (40TE) for small generator (16 I/P & 7 O/P)
- Figure 15 - P342 (40TE) for small generator (12 I/P & 11 O/P)
- Figure 16 - P342 (40TE) for small generator (8 I/P & 11O/P (4 HB))
- Figure 17 - P342 (60TE) for small generator (16 I/P & 16 O/P & RTD's & CLIO)
- Figure 18 - P342 (60TE) for small generator (24 I/P & 16 O/P & RTD's
- Figure 19 - P342 (60TE) for small generator (16 I/P & 24 O/P & RTD's
- Figure 20 - P342 (60TE) for small generator (16 I/P & 20 O/P (4HB))
- Figure 21 - P342 (60TE) for small generator (16 I/P & 12 O/P (4HB) & RTD's & CLIO)

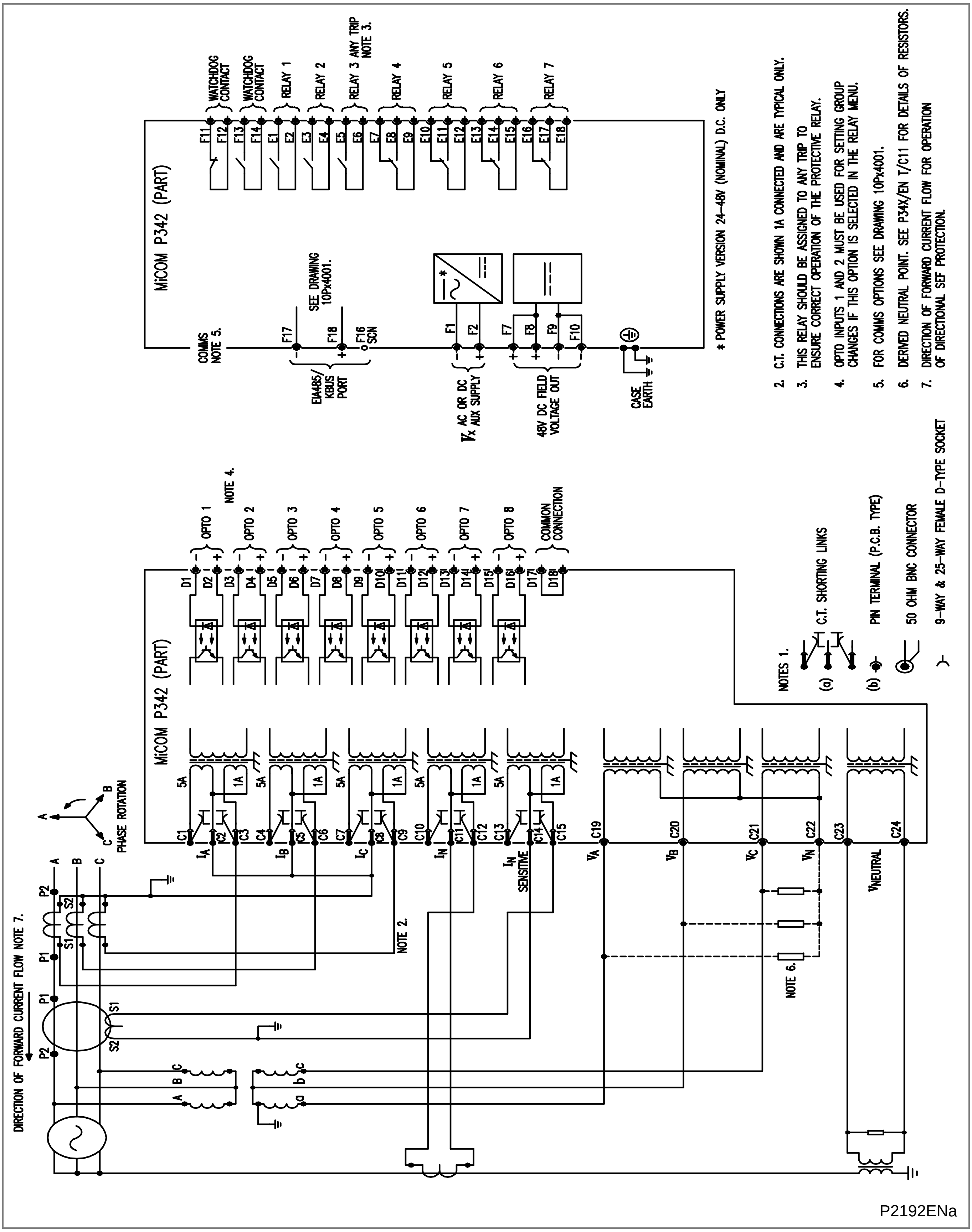


Figure 8 - P342 (40TE) for small generator using VEE connected VT's (8 I/P & 7 O/P)

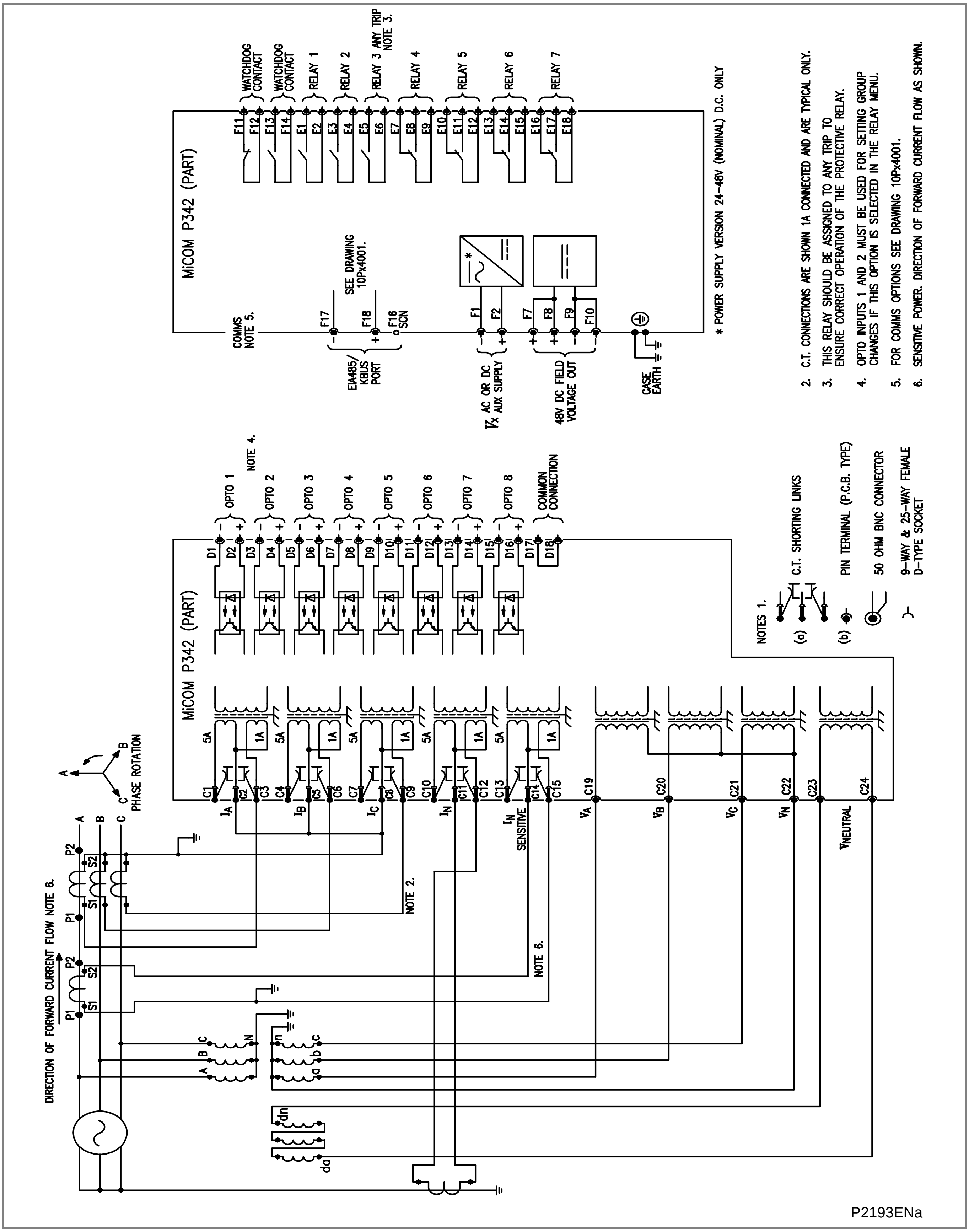


Figure 9 - P342 (40TE) for small generator with sensitive power (8 I/P & 7 O/P)

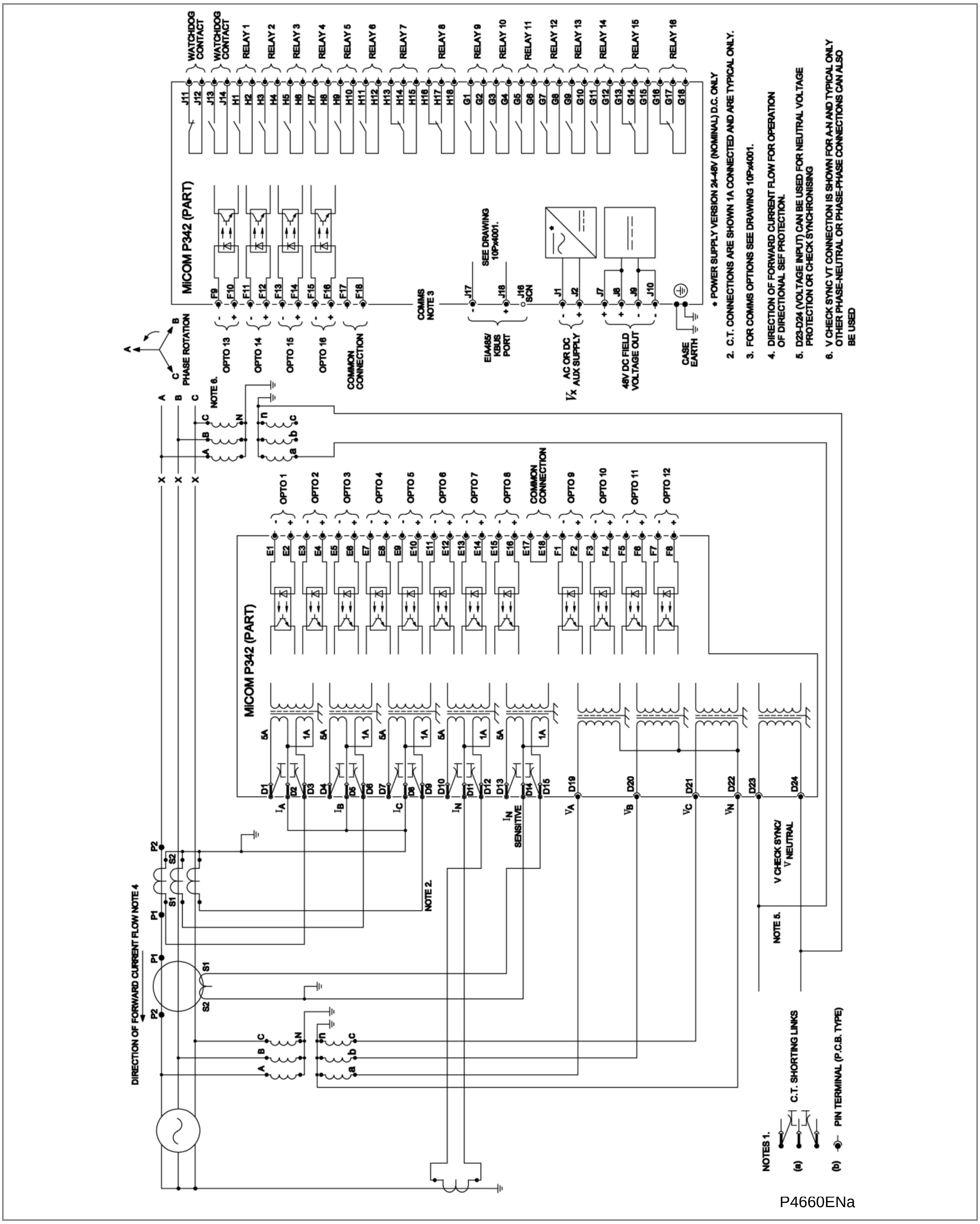


Figure 10 - P342 (40TE) for small generator with check synch (8 I/P & 7 O/P)

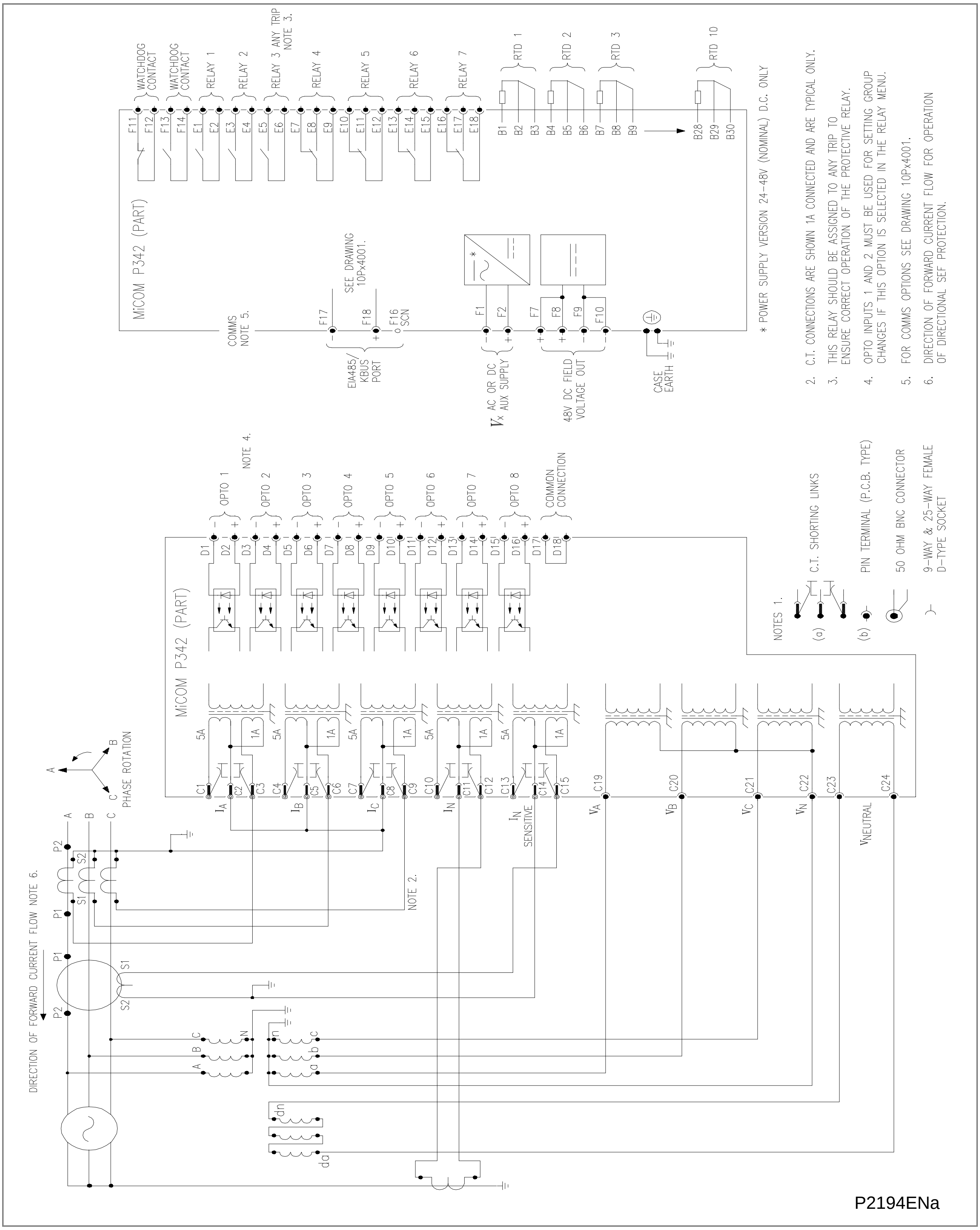


Figure 11 - P342 (40TE) for small generator (8 I/P & 7 O/P & RTD's)

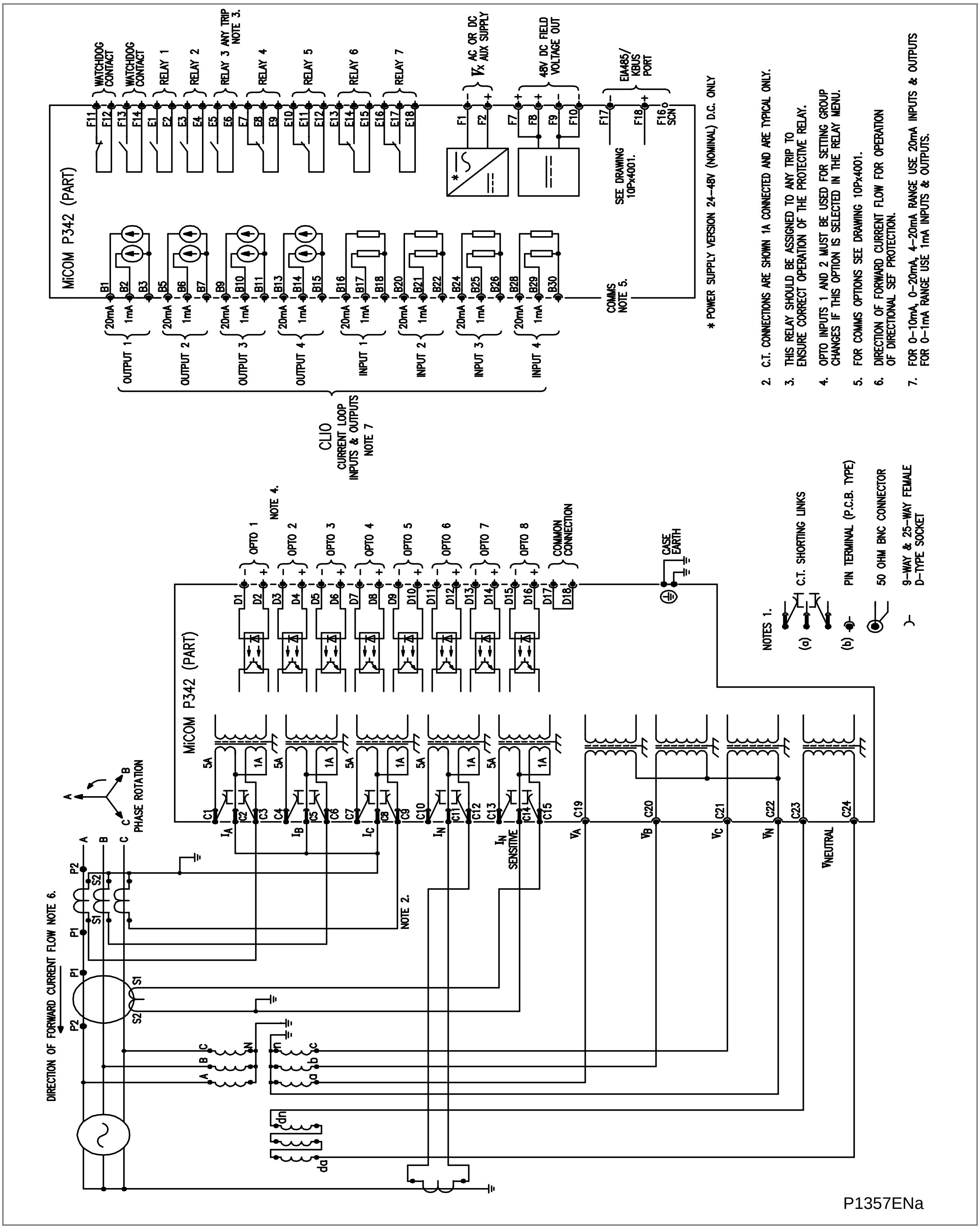


Figure 12 - P342 (40TE) for small generator (8 I/P & 7 O/P & CLIO)

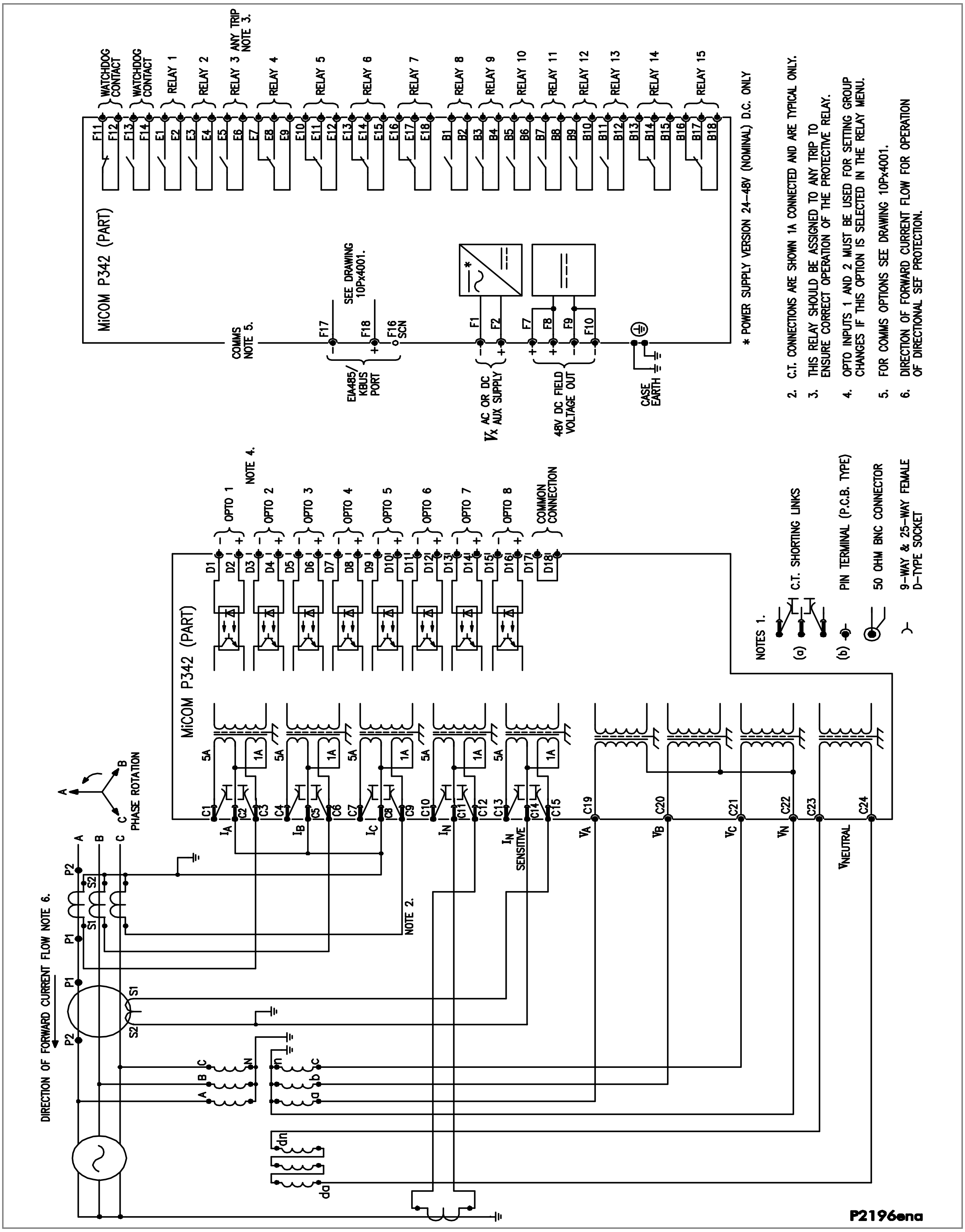


Figure 13 - P342 (40TE) for small generator (8 I/P & 15 O/P)

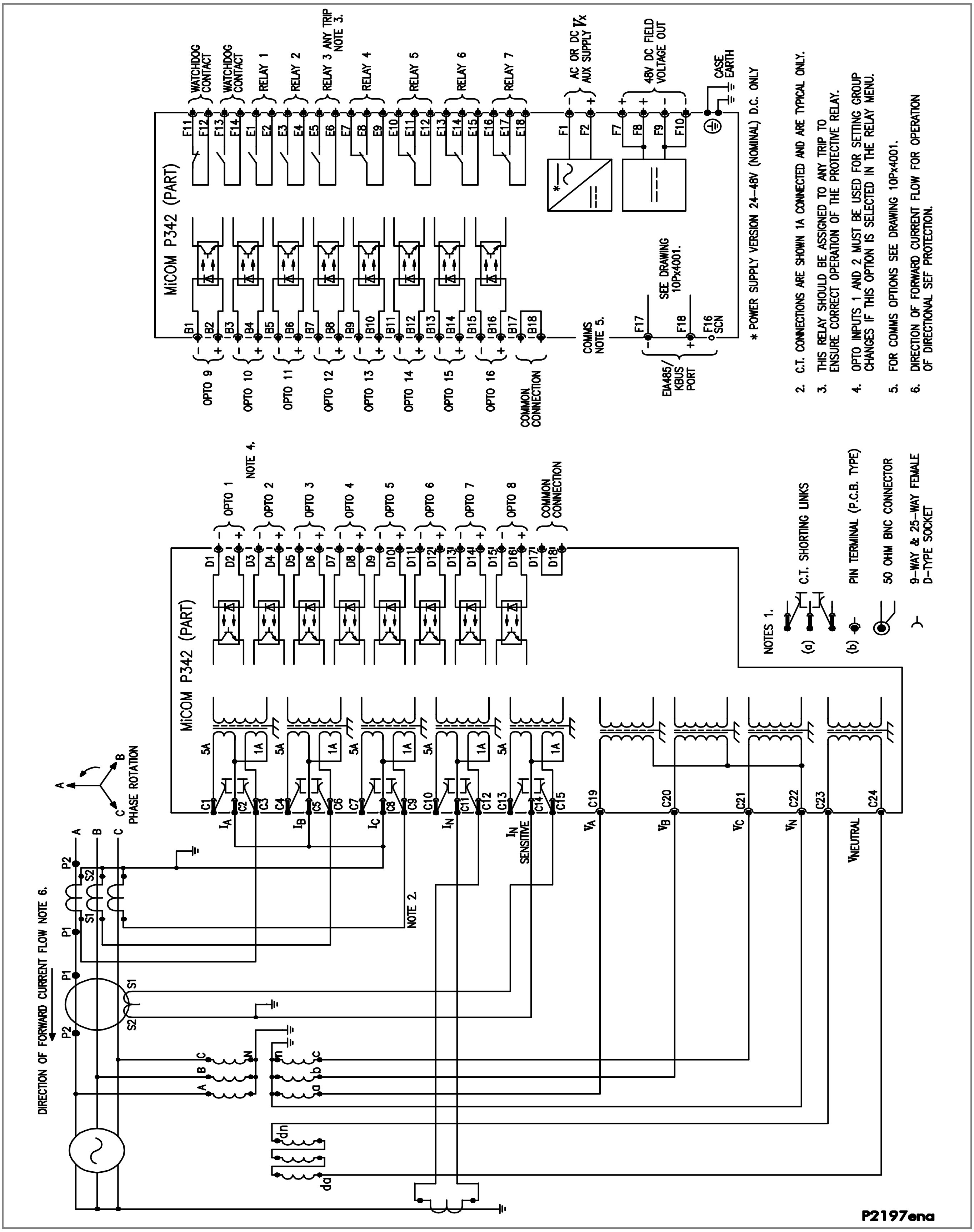


Figure 14 - P342 (40TE) for small generator (16 I/P & 7 O/P)

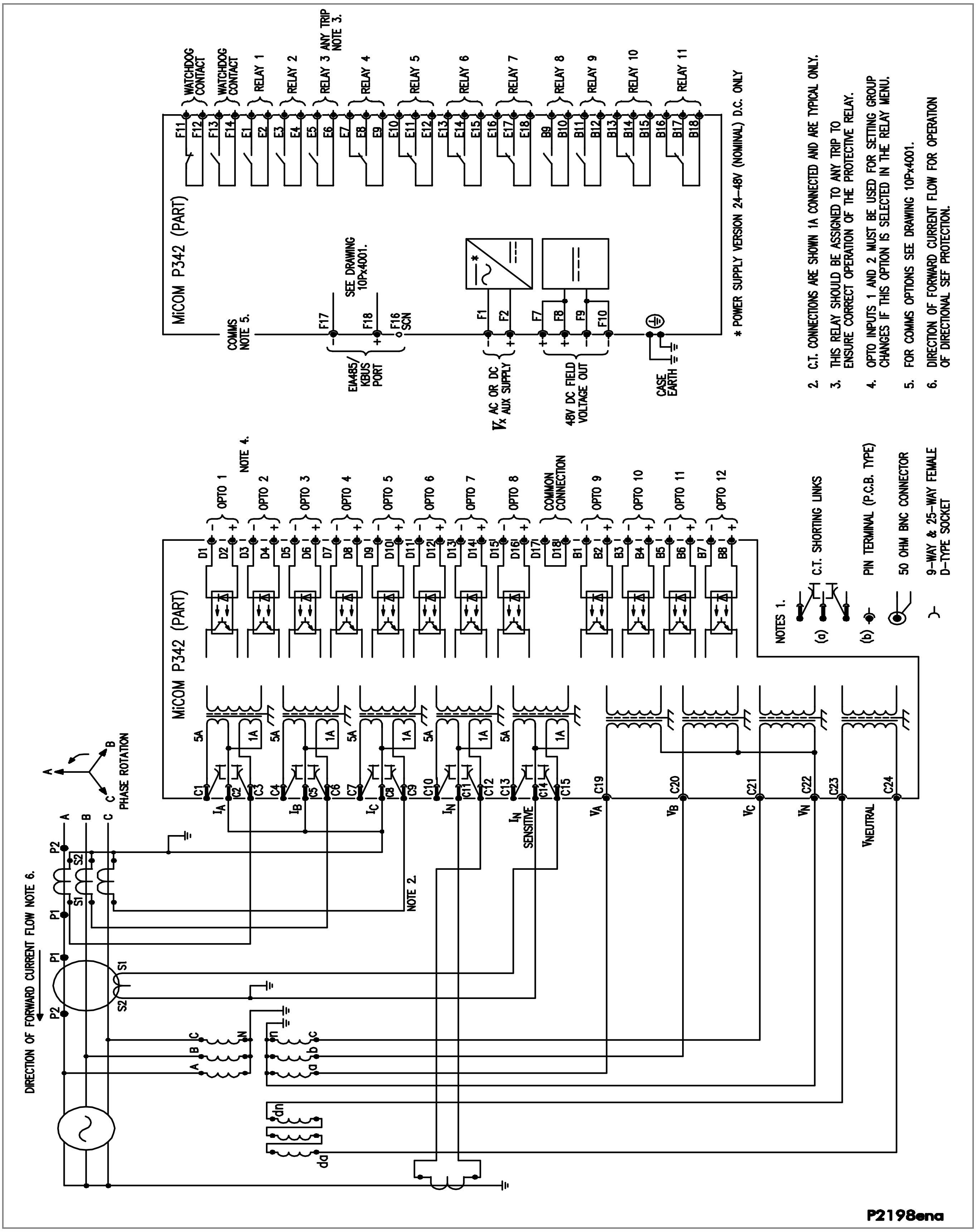


Figure 15 - P342 (40TE) for small generator (12 I/P & 11 O/P)

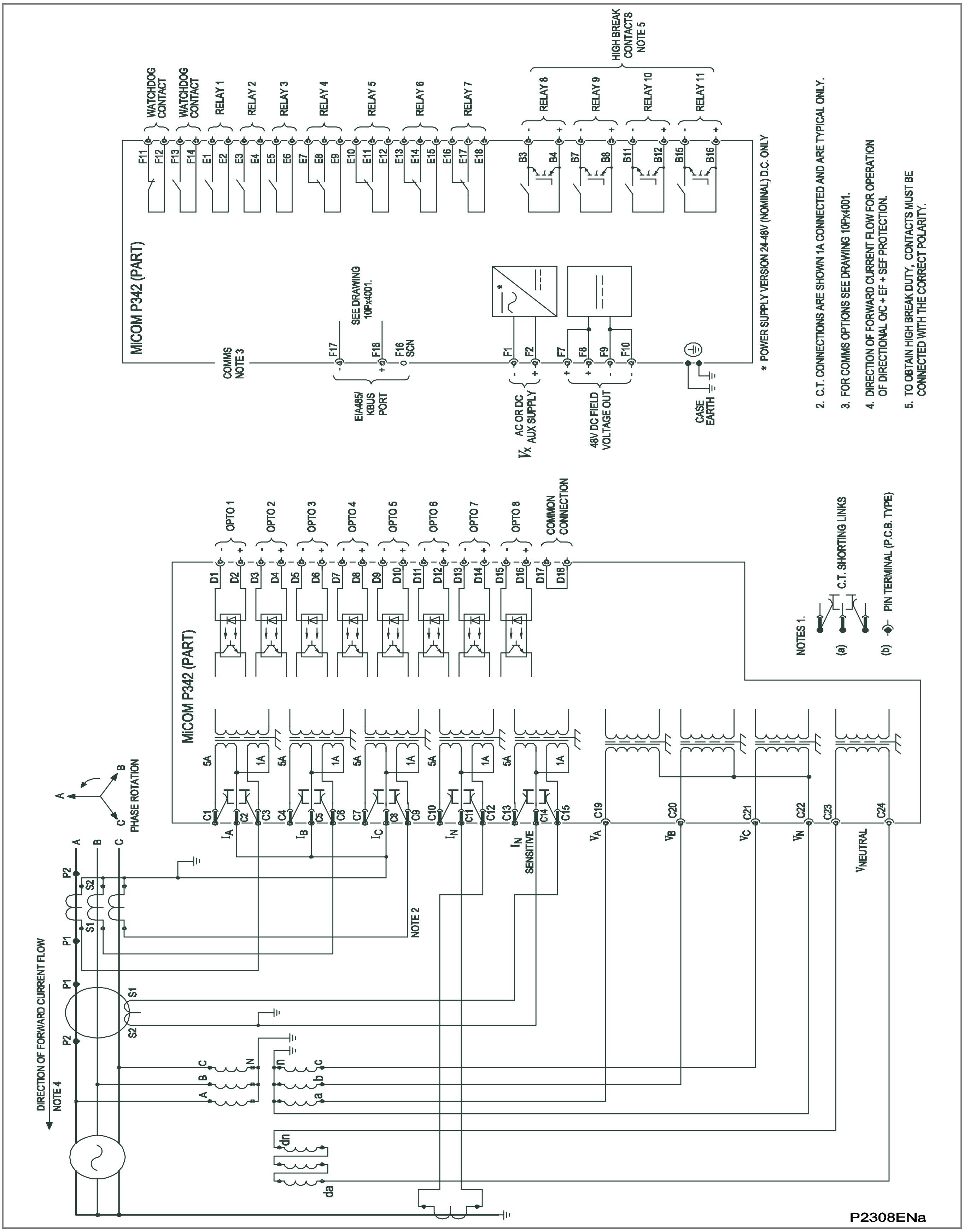


Figure 16 - P342 (40TE) for small generator (8 I/P & 11O/P (4 HB))

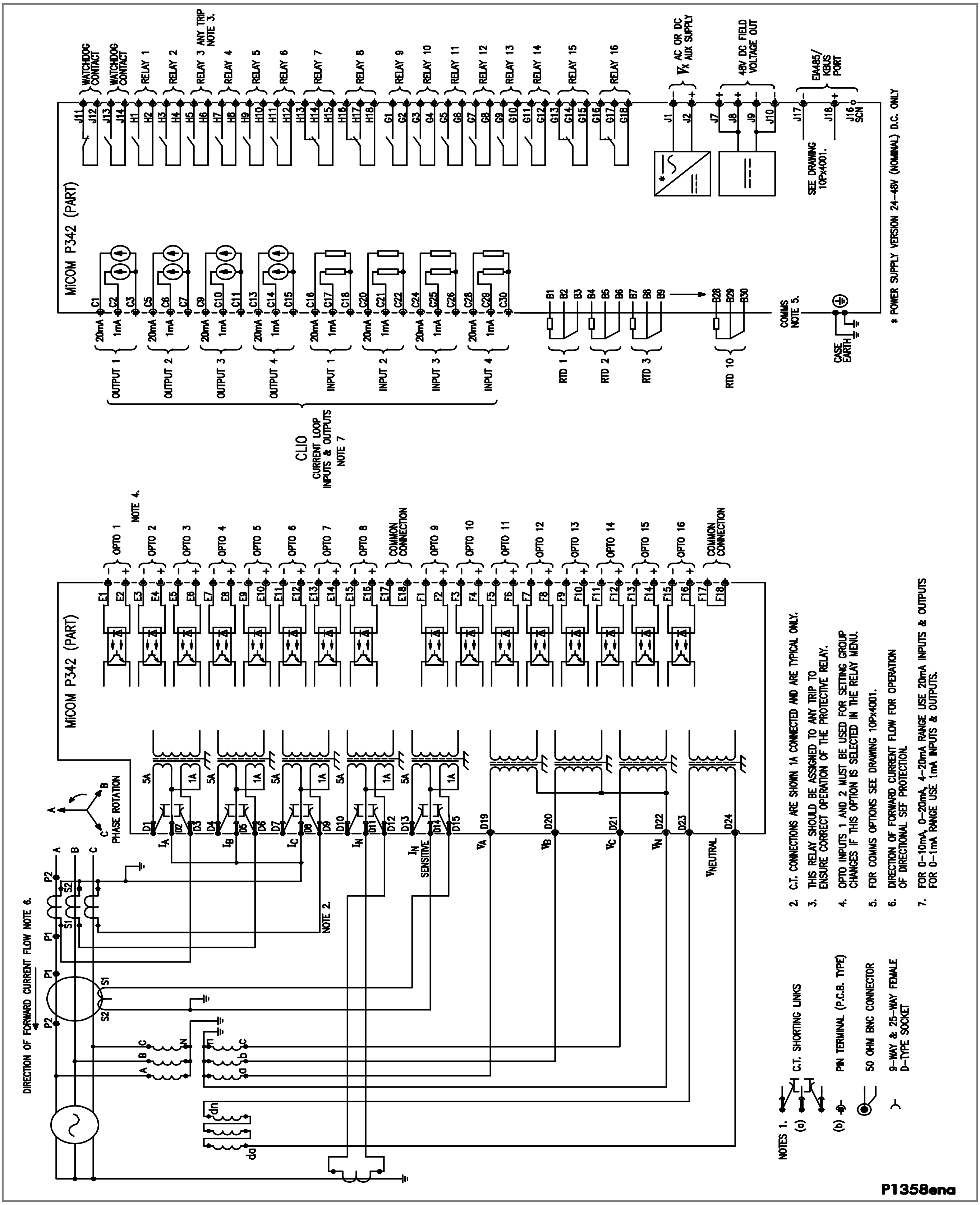


Figure 17 - P342 (60TE) for small generator (16 I/P & 16 O/P & RTD's & CLIO)

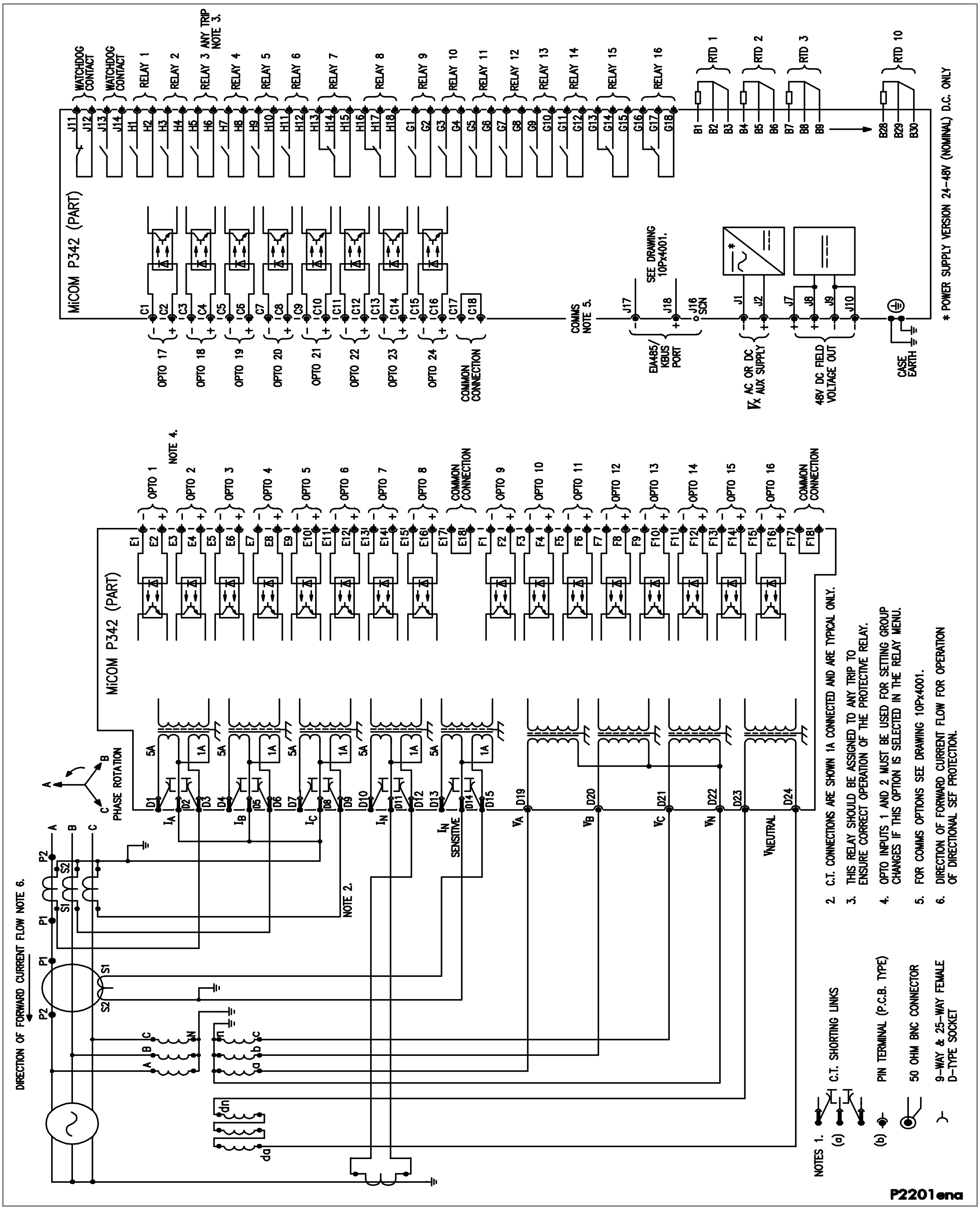


Figure 18 - P342 (60TE) for small generator (24 I/P & 16 O/P & RTD's

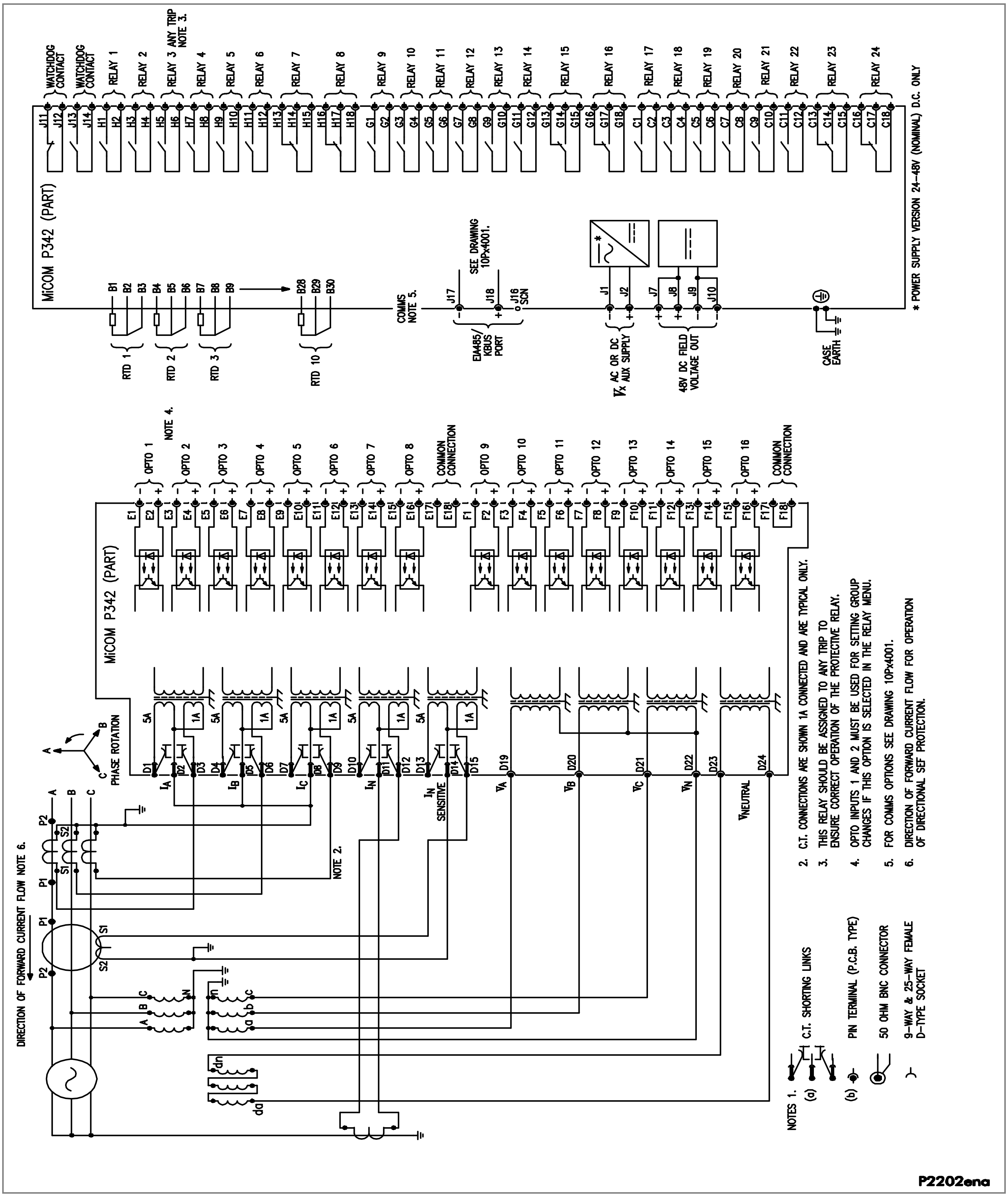


Figure 19 - P342 (60TE) for small generator (16 I/P & 24 O/P & RTD's

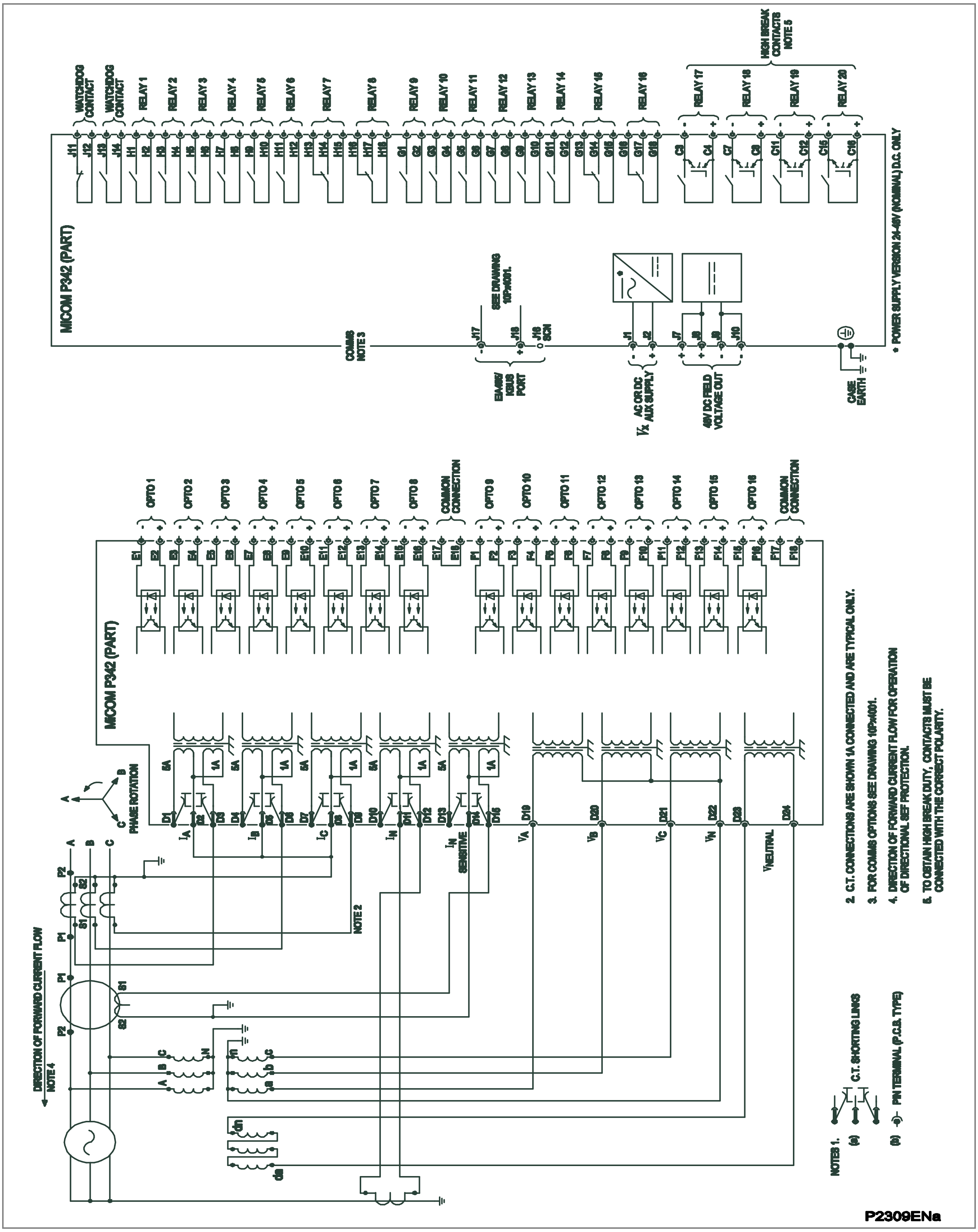


Figure 20 - P342 (60TE) for small generator (16 I/P & 20 O/P (4HB))

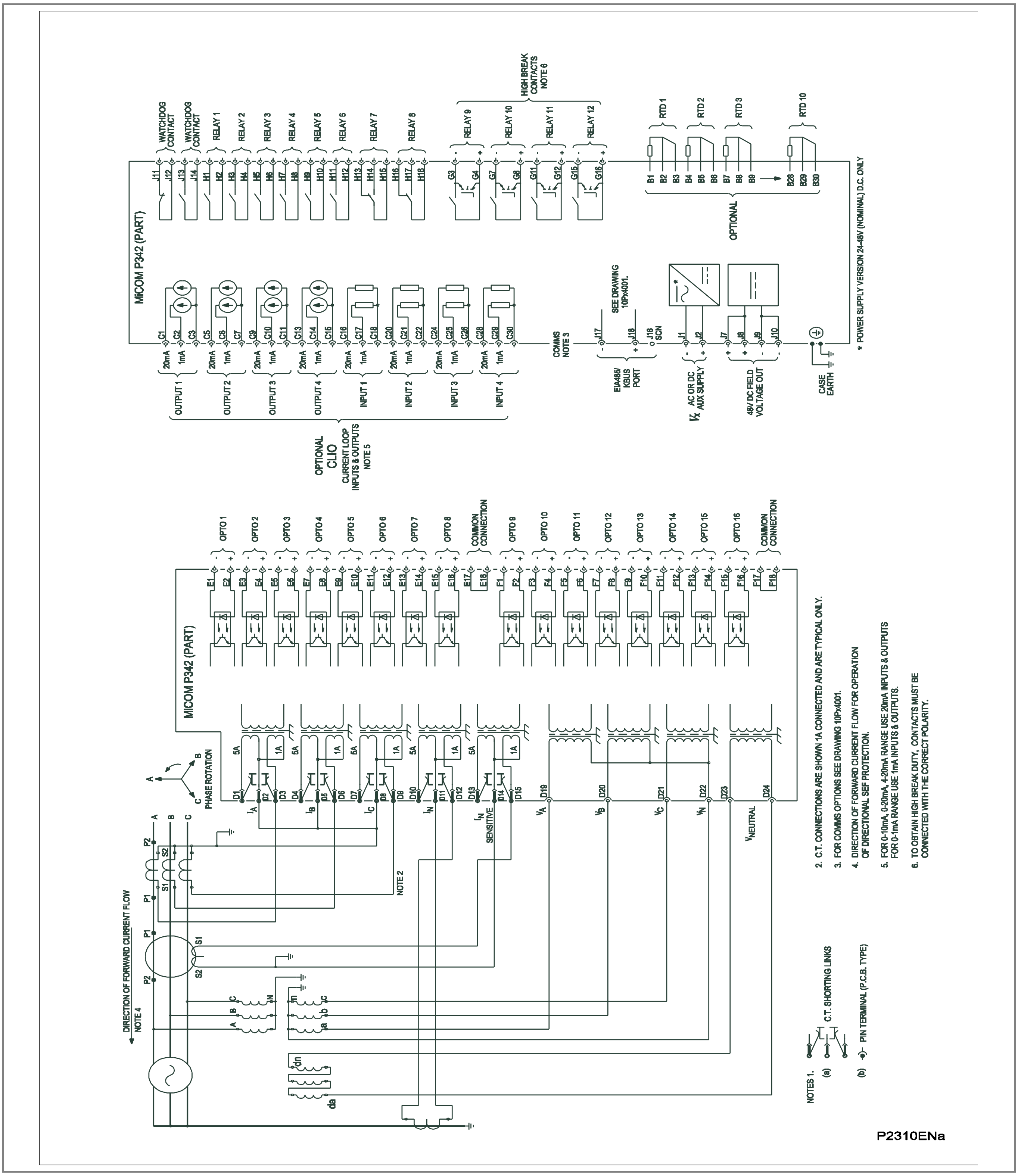


Figure 21 - P342 (60TE) for small generator (16 I/P & 12 O/P (4HB) & RTD's & CLIO)

Notes:

6 P343 CONNECTION DIAGRAMS

This section includes the following diagrams:

- Figure 22 - P343 (60TE) for biased differential (16 I/P & 14 O/P & RTD's)
- Figure 23 - P343 (60TE) with high impedance differential (16 I/P & 14 O/P)
- Figure 24 - P343 (60TE) with high impedance differential (16 I/P & 14 O/P)
- Figure 25 - P343 Generator protection relay with biased differential using VEE connected VT's and sensitive power (16 I/P & 14 O/P)
- Figure 26 - P343 (60TE) for biased generator-transformer differential (16 I/P & 14 O/P)
- Figure 27 - P343 (60TE) for biased differential and check synchronizing (16 I/P & 14 O/P)
- Figure 28 - P343 (60TE) with biased differential (16 I/P & 14 O/P & CLIO)
- Figure 29 - P343 (60TE) with biased differential (24 I/P & 14 O/P)
- Figure 30 - P343 (60TE) with biased differential (16 I/P & 22 O/P)
- Figure 31 - P343 (60TE) with biased differential (16 I/P & 18 O/P (4HB))
- Figure 32 - P343 (60TE) with biased differential (16 I/P & 11 O/P (4HB) & RTD's)
- Figure 33 - P343 (60TE) with biased differential (16 I/P & 11 O/P (4HB) & CLIO)
- Figure 34 - P343 (80TE) with biased differential (24 I/P & 24 O/P RTD's & CLIO)
- Figure 35 - P343 (80TE) with biased differential (32 I/P & 24 O/P & RTD's)
- Figure 36 - P343 (80TE) with biased differential (24 I/P & 32 O/P & RTD's)
- Figure 37 - P343 (80TE) with biased differential (32 I/P & 16 O/P & RTD & CLIO)
- Figure 38 - P343 (80TE) with biased differential (16 I/P & 32 O/P & RTD & CLIO)
- Figure 39 - P343 (80TE) with biased differential (16 I/P & 24 O/P (8 HB) & RTD's & CLIO)

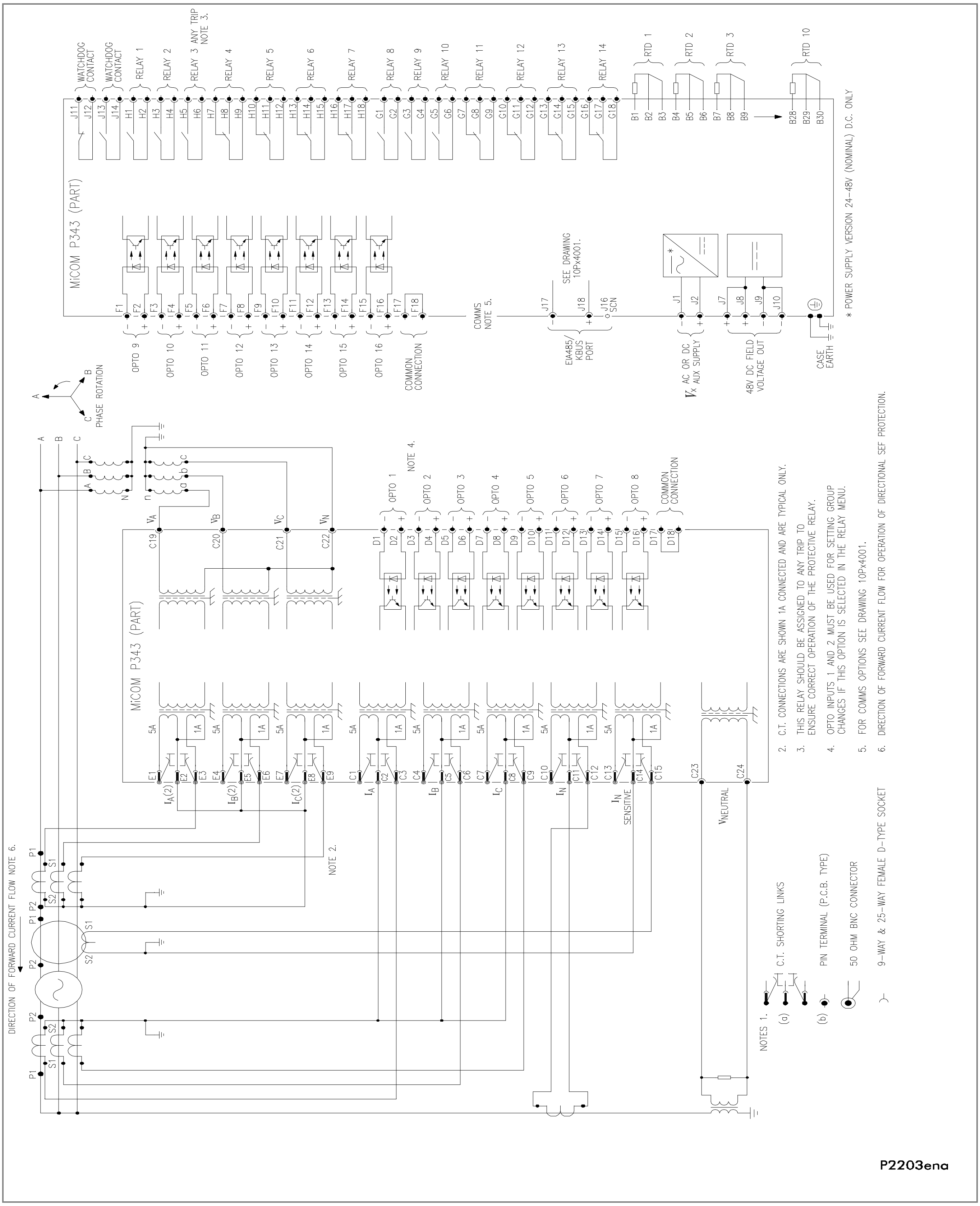


Figure 22 - P343 (60TE) for biased differential (16 I/P & 14 O/P & RTD’s)

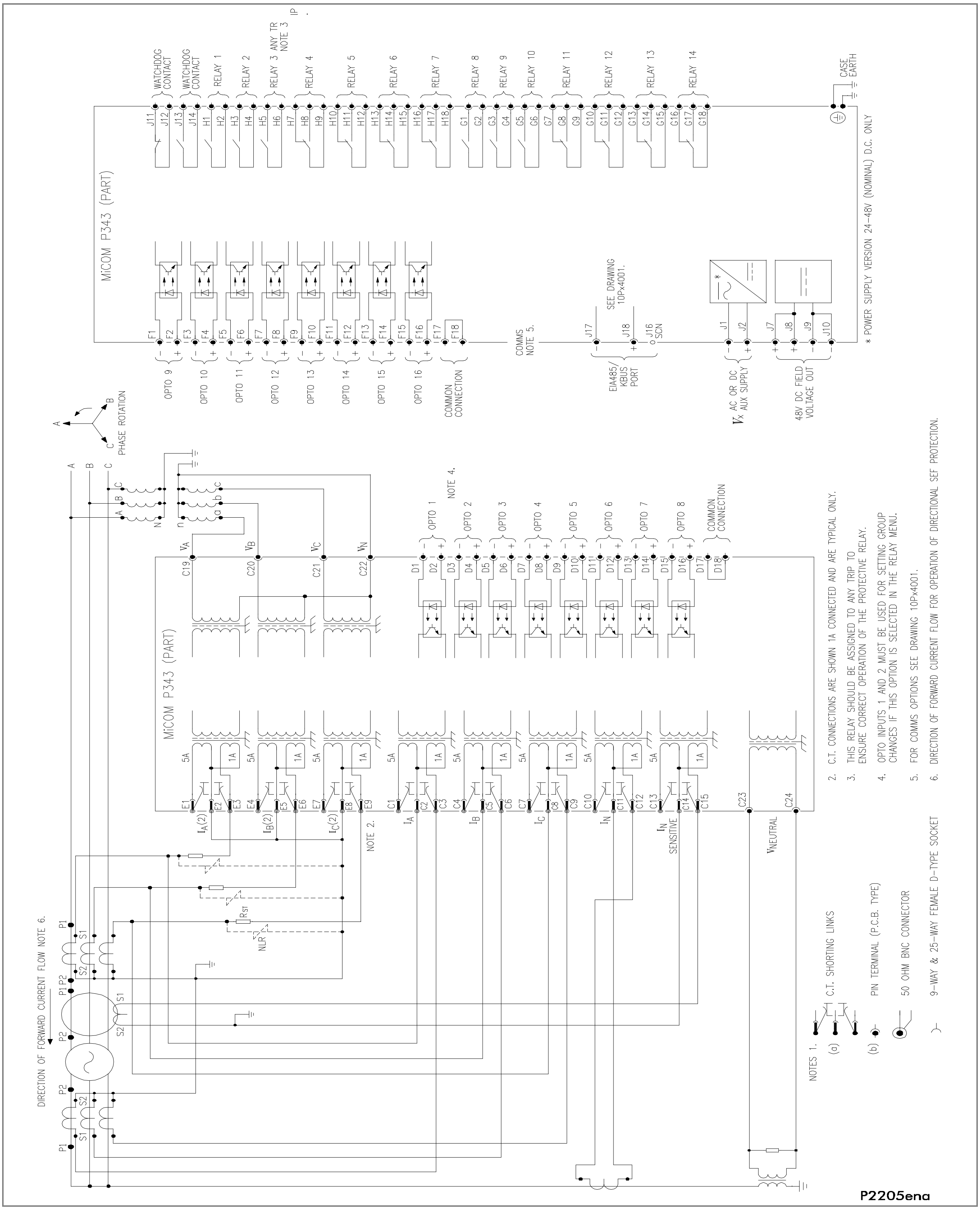


Figure 23 - P343 (60TE) with high impedance differential (16 I/P & 14 O/P)

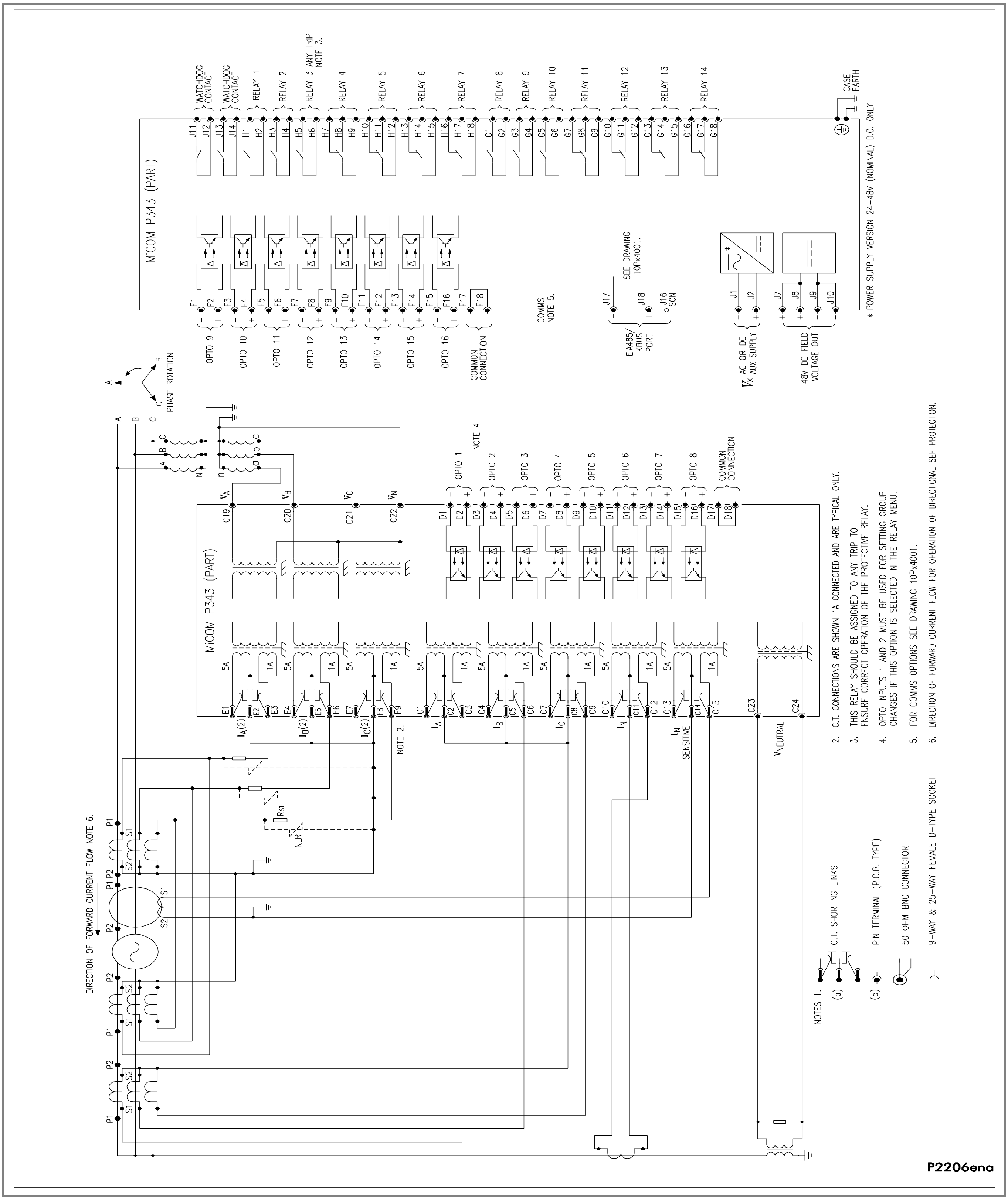


Figure 24 - P343 (60TE) with high impedance differential (16 I/P & 14 O/P)

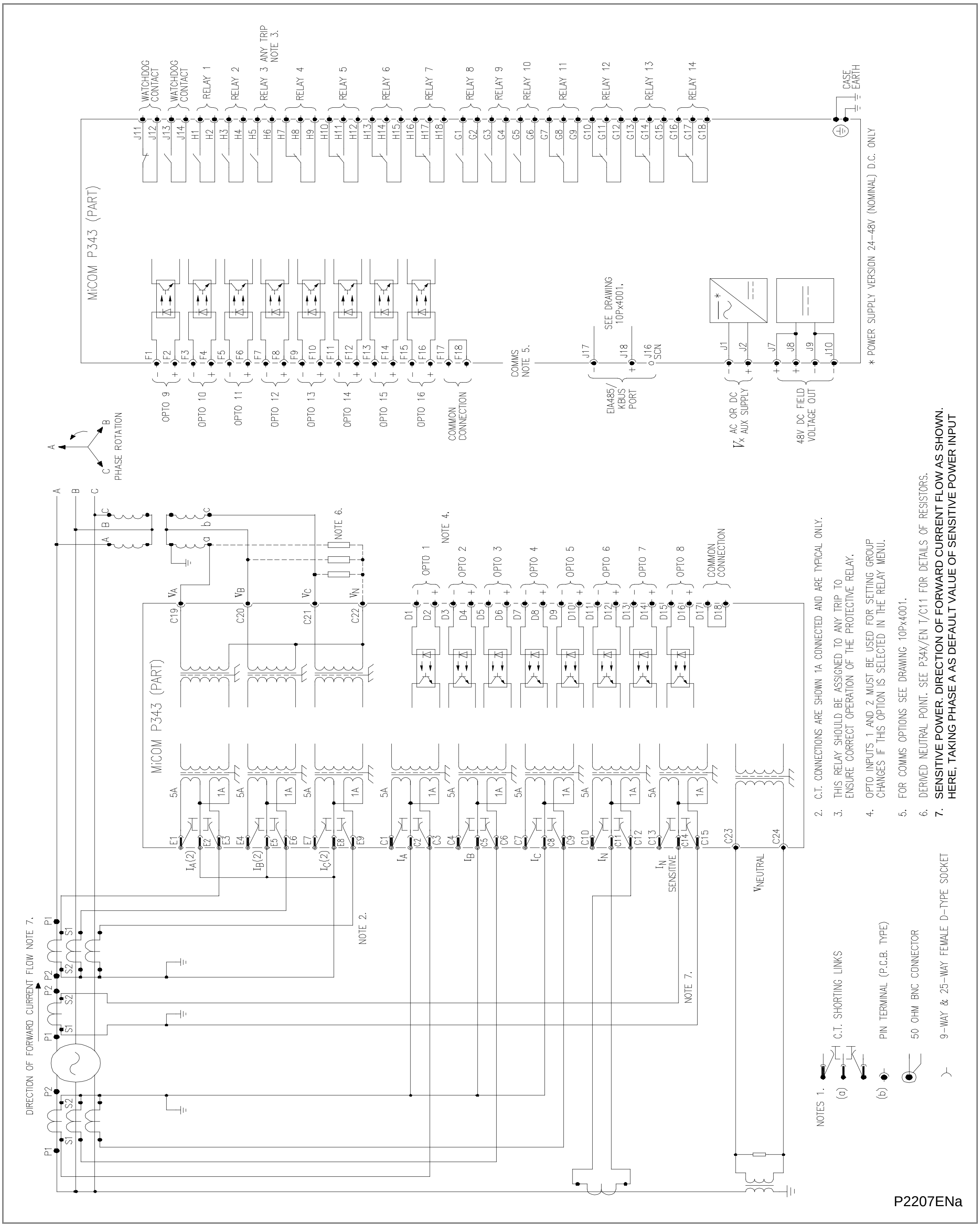


Figure 25 - P343 Generator protection relay with biased differential using VEE connected VT's and sensitive power (16 I/P & 14 O/P)

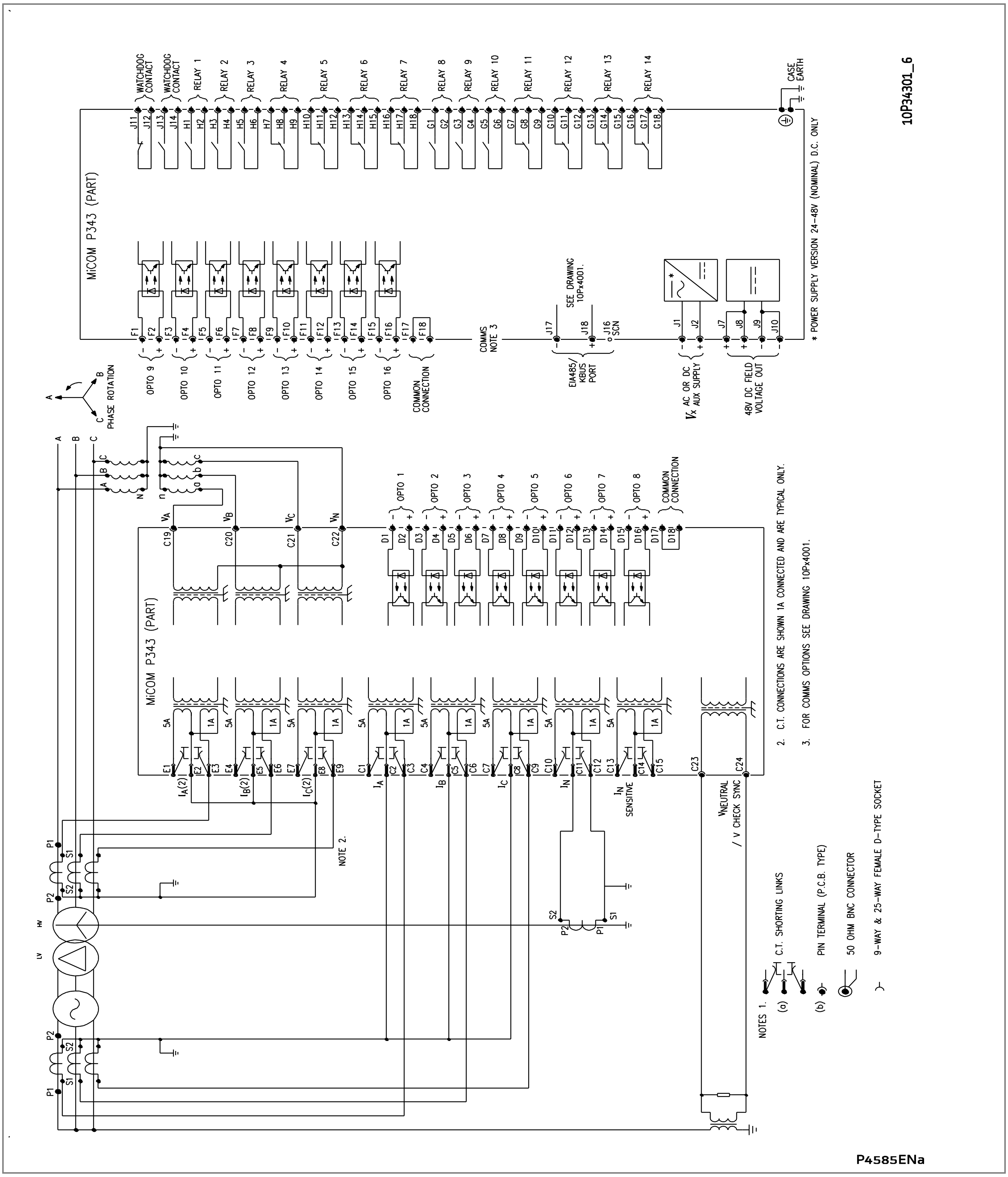


Figure 26 - P343 (60TE) for biased generator-transformer differential (16 I/P & 14 O/P)

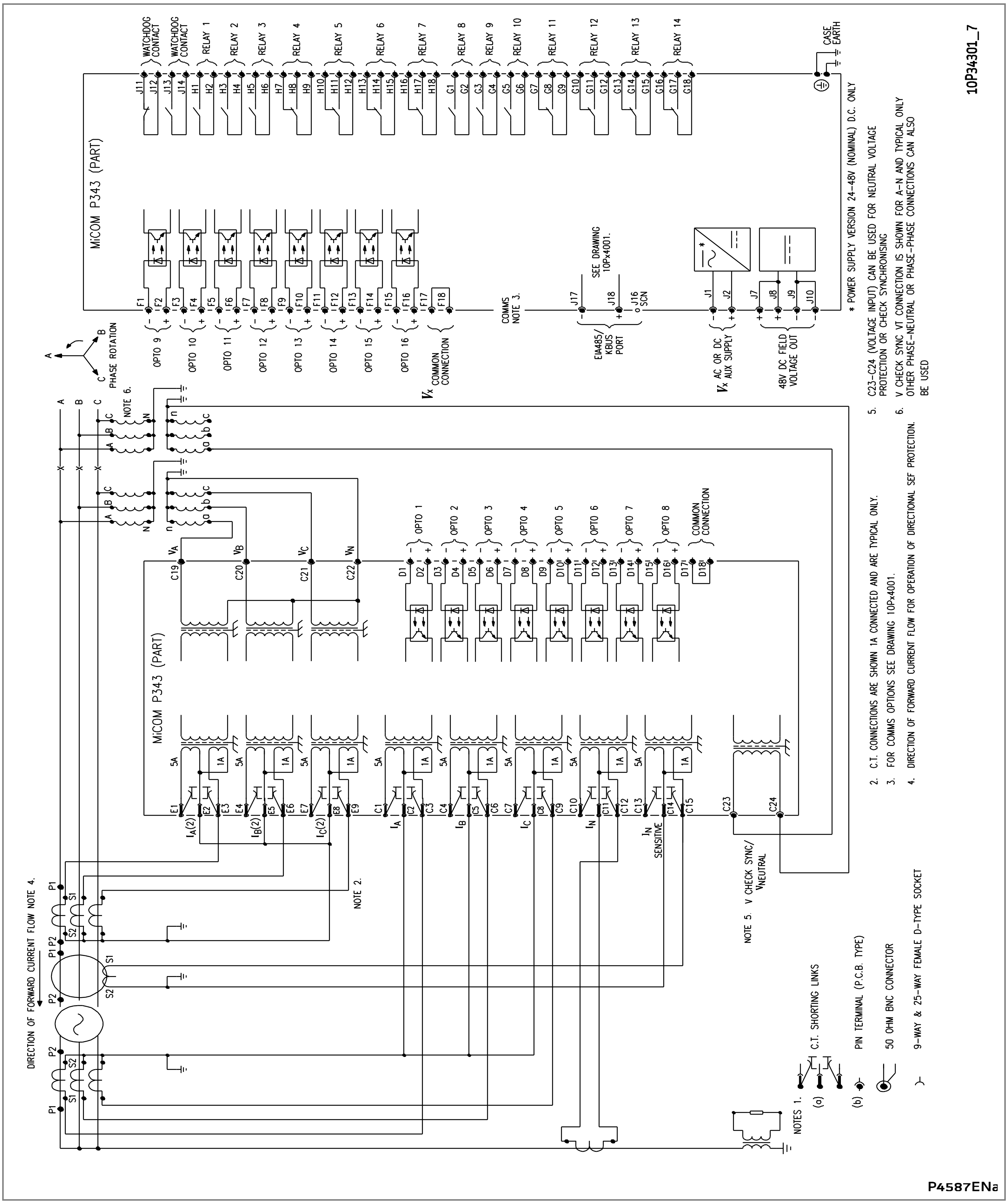


Figure 27 - P343 (60TE) for biased differential and check synchronizing (16 I/P & 14 O/P)

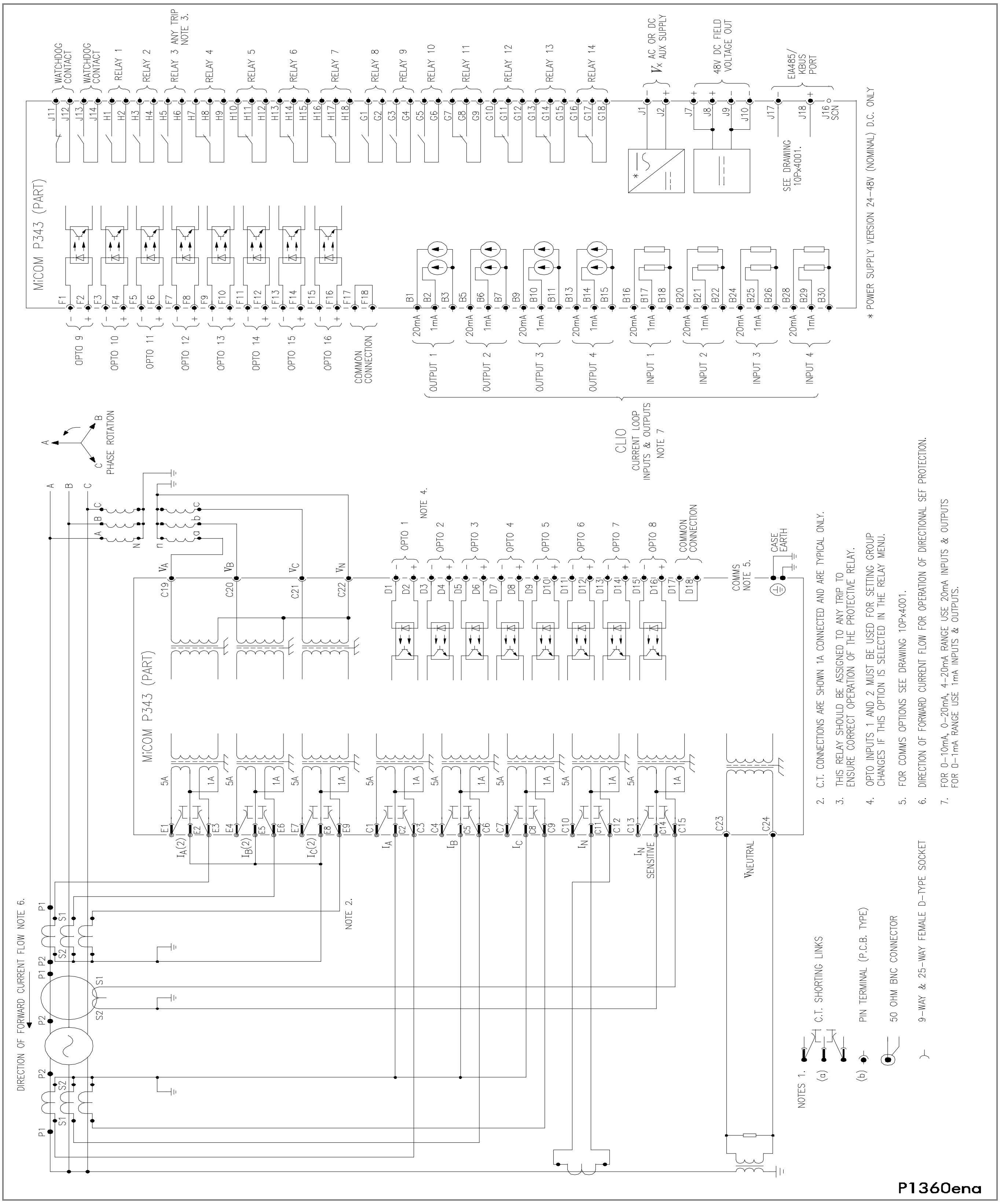


Figure 28 - P343 (60TE) with biased differential (16 I/P & 14 O/P & CLIO)

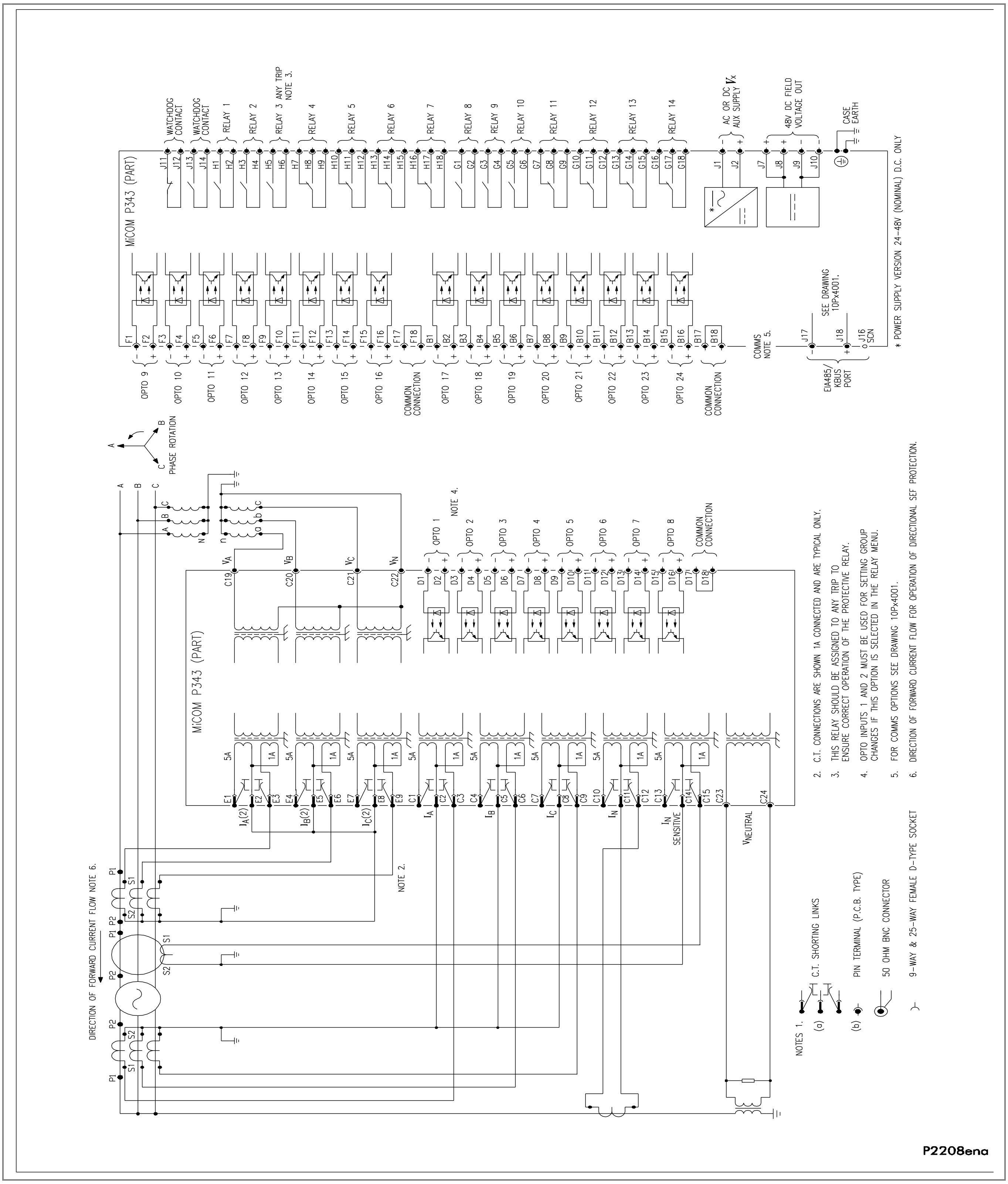


Figure 29 - P343 (60TE) with biased differential (24 I/P & 14 O/P)

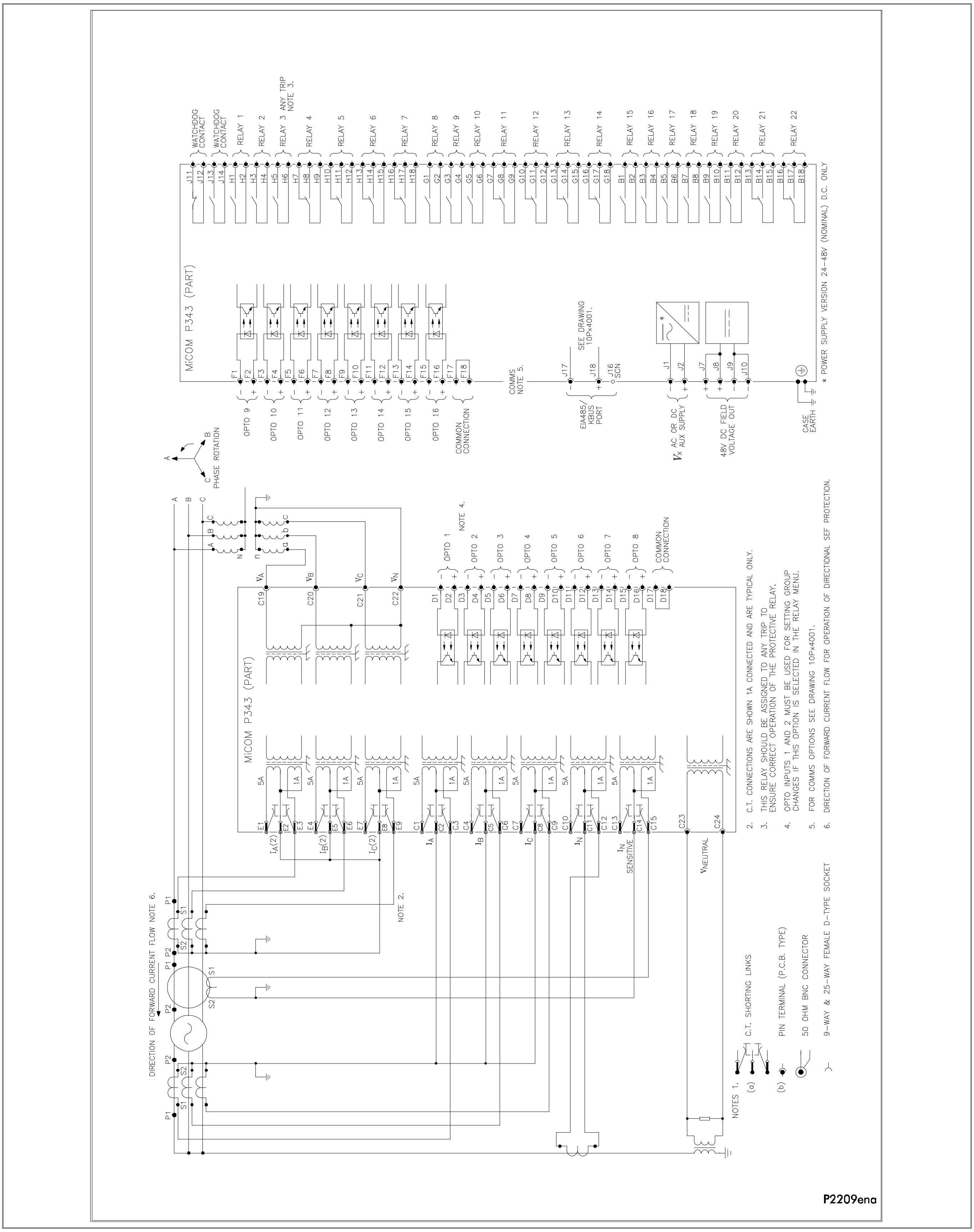


Figure 30 - P343 (60TE) with biased differential (16 I/P & 22 O/P)

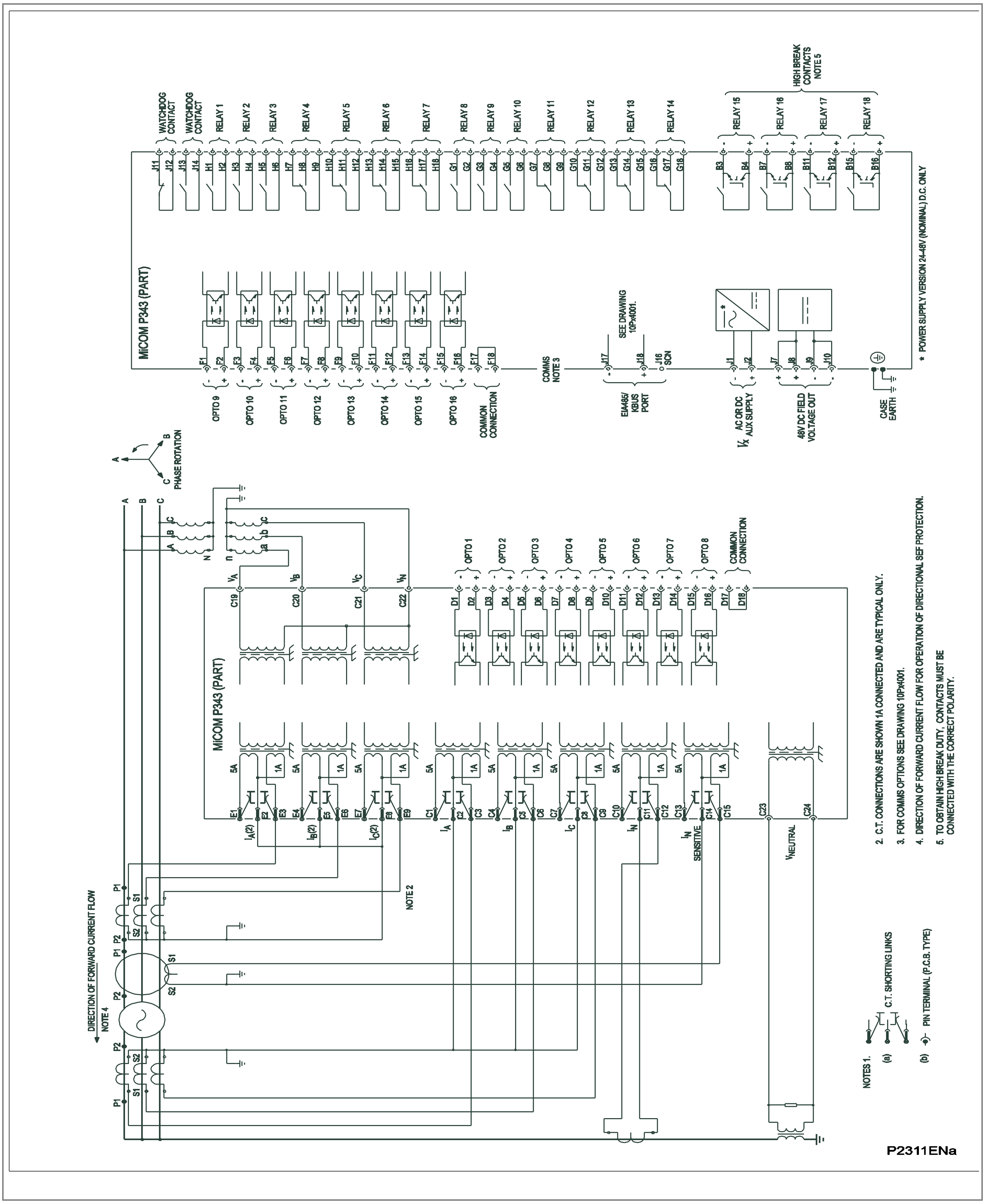


Figure 31 - P343 (60TE) with biased differential (16 I/P & 18 O/P (4HB))

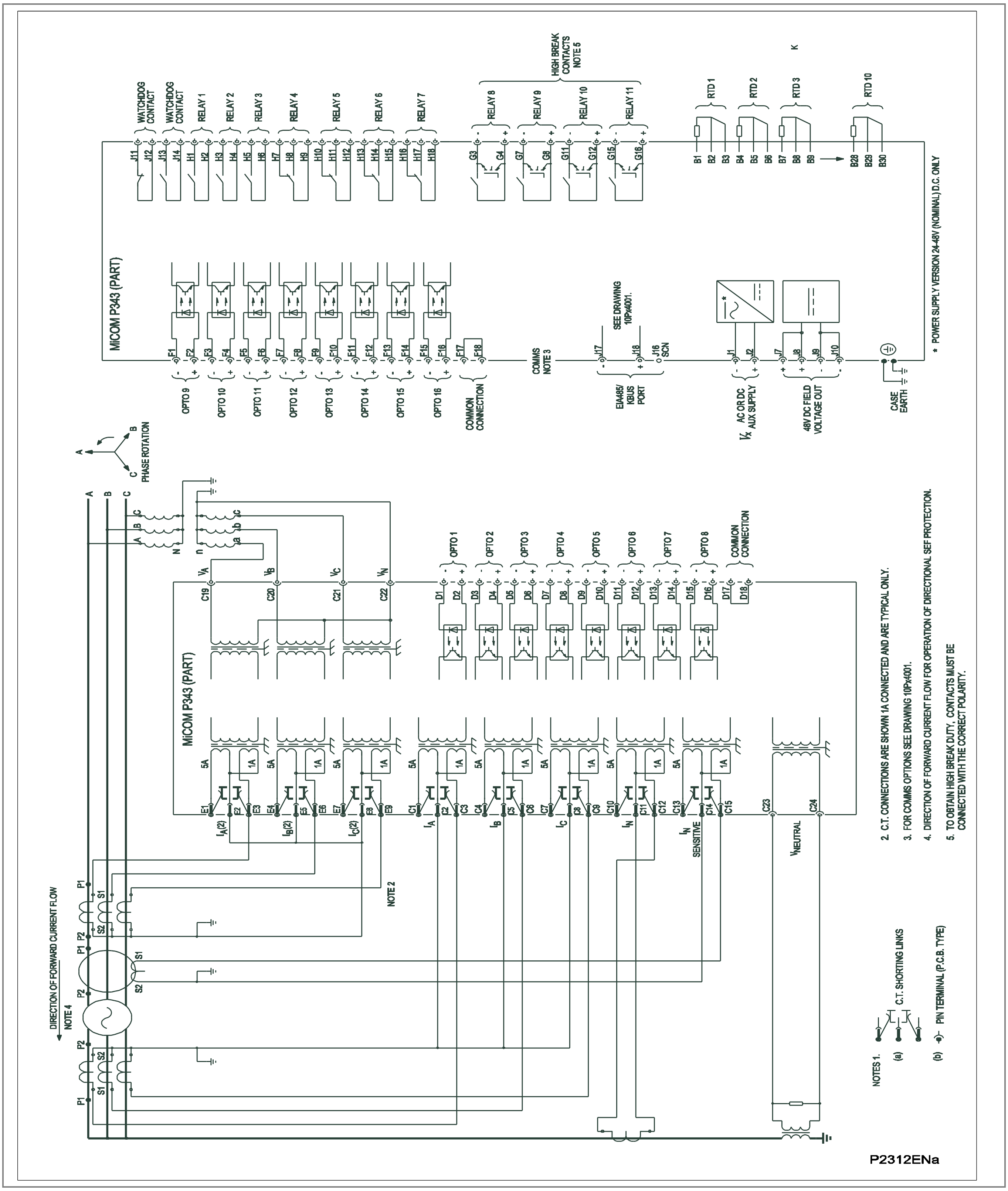


Figure 32 - P343 (60TE) with biased differential (16 I/P & 11 O/P (4HB) & RTD’s)

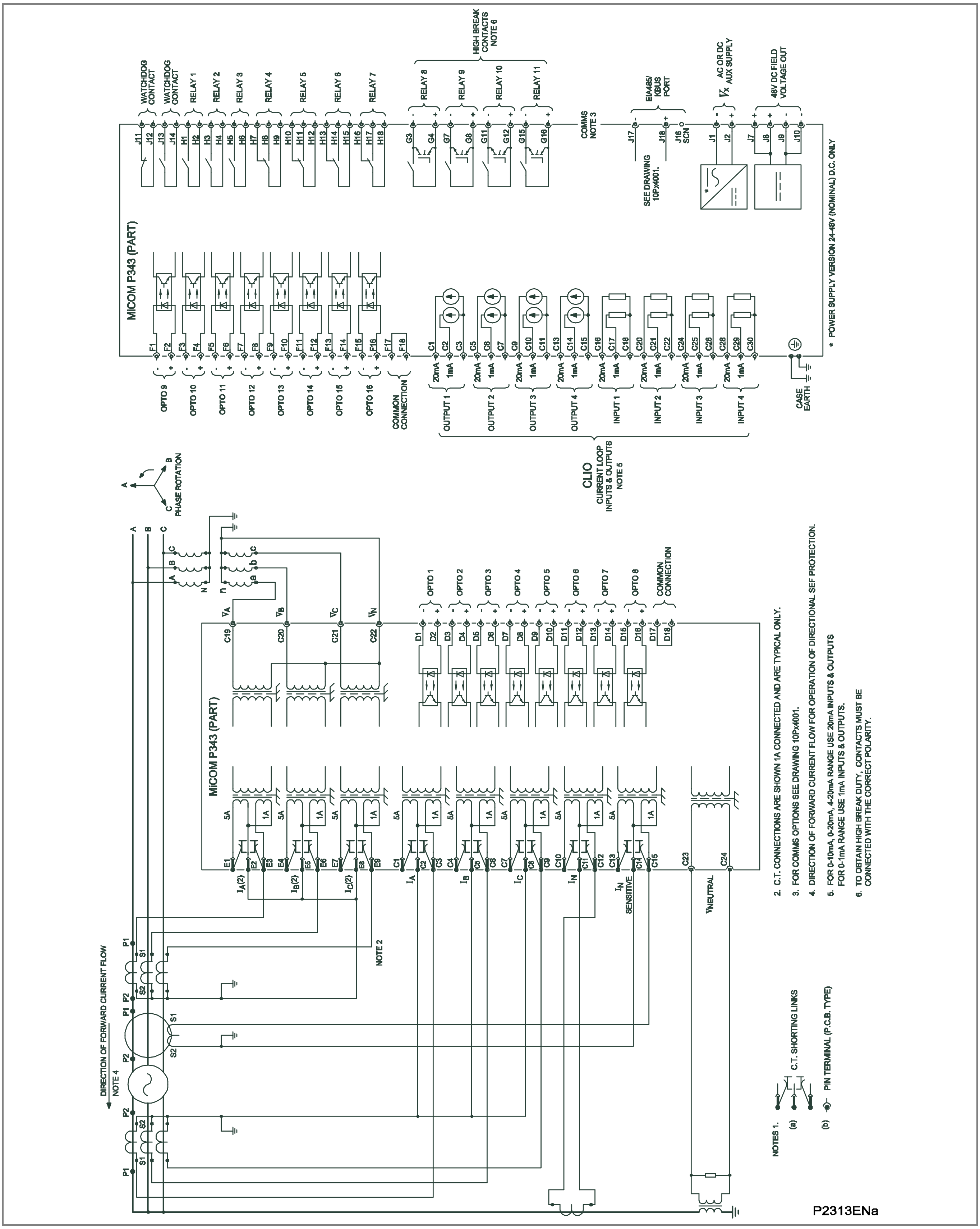


Figure 33 - P343 (60TE) with biased differential (16 I/P & 11 O/P (4HB) & CLIO)

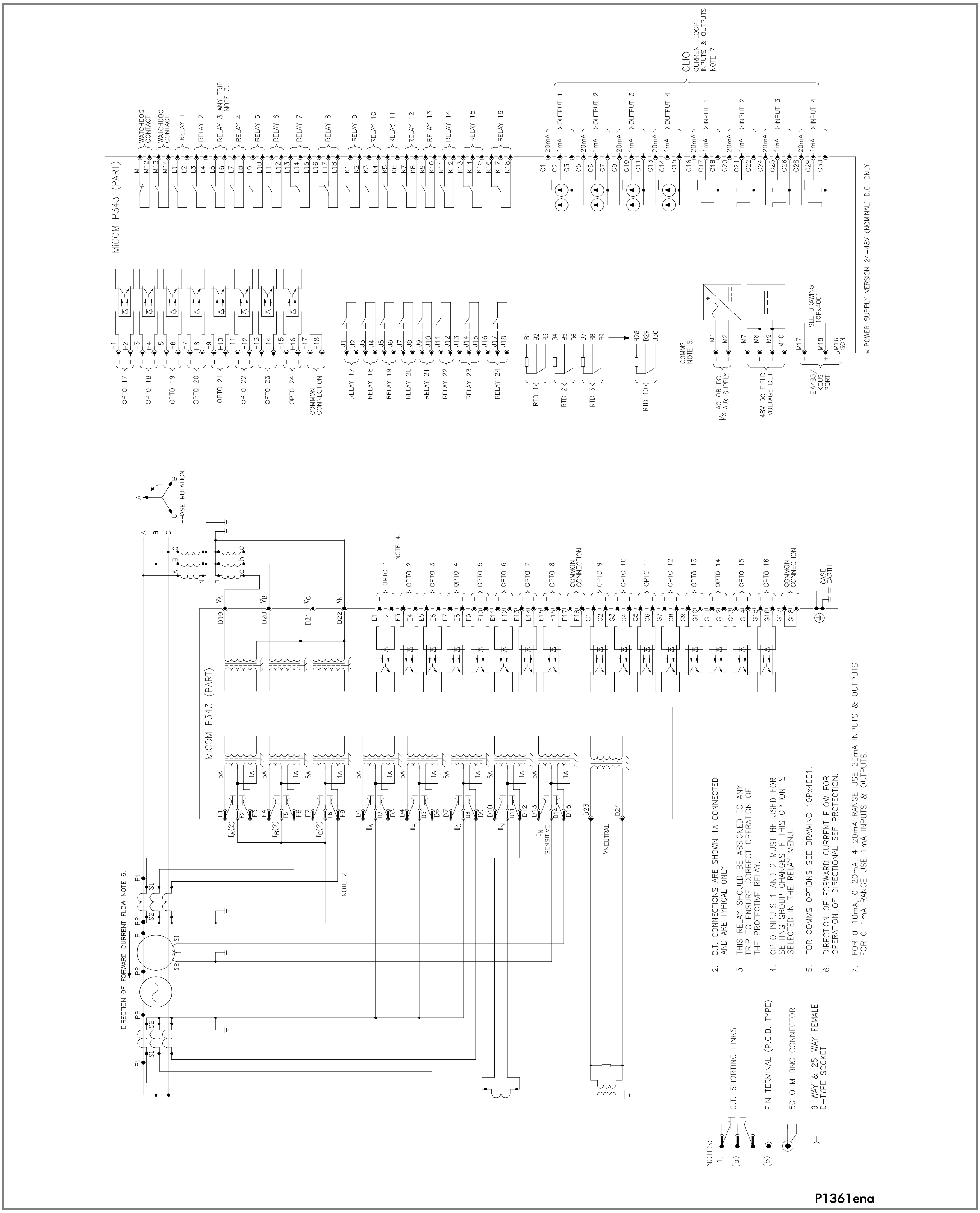


Figure 34 - P343 (80TE) with biased differential (24 I/P & 24 O/P RTD's & CLIO)

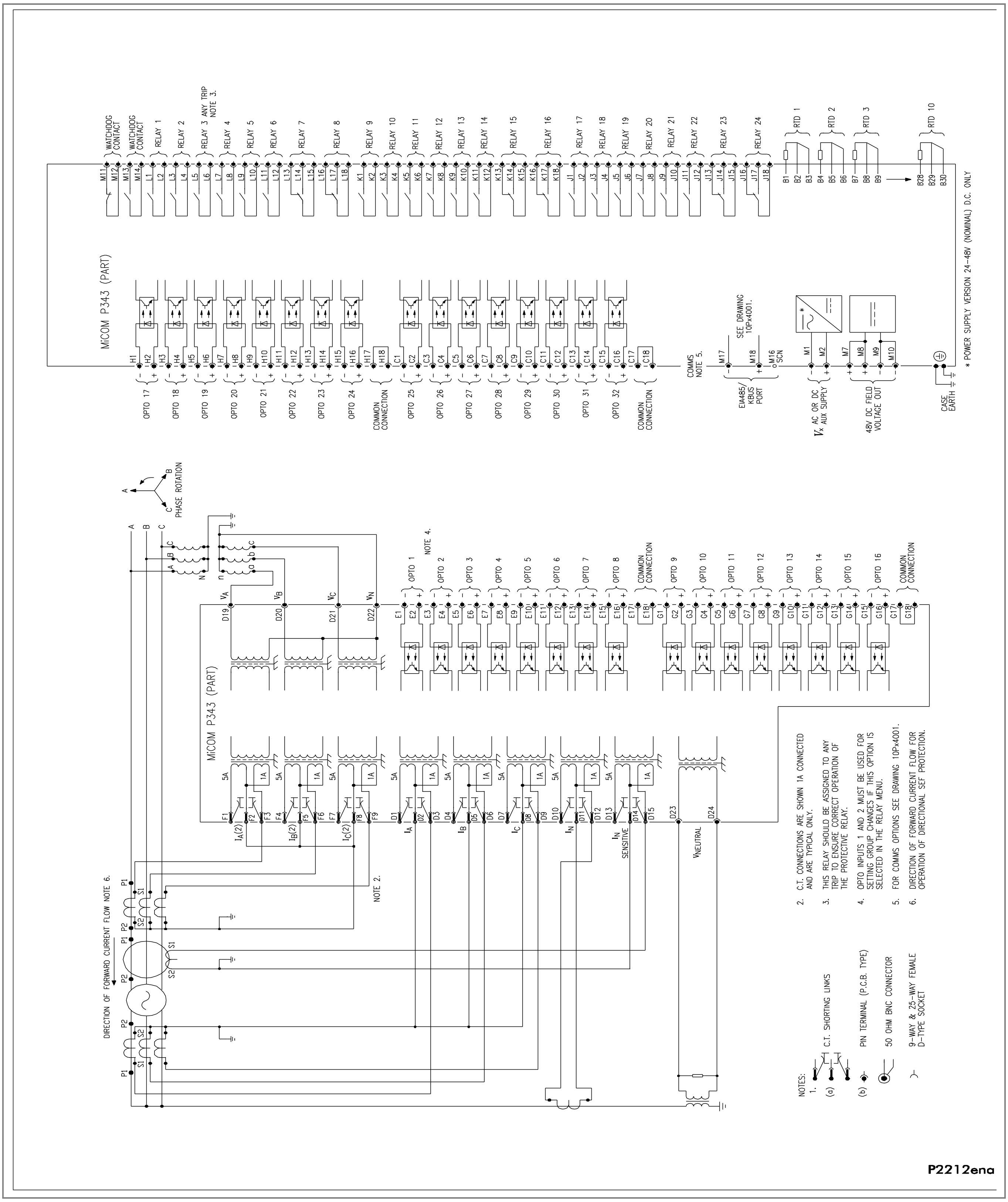


Figure 35 - P343 (80TE) with biased differential (32 I/P & 24 O/P & RTD's)

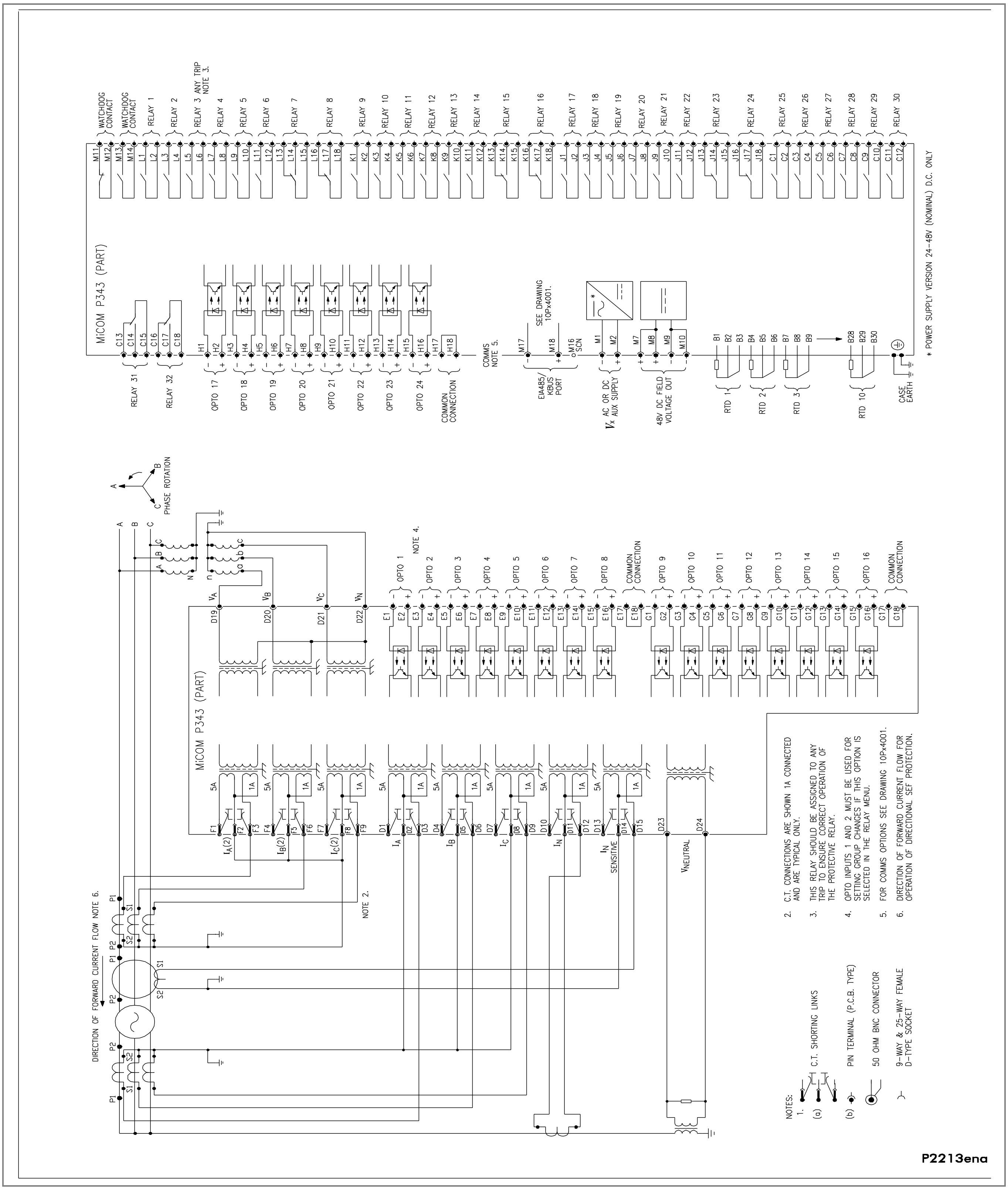


Figure 36 - P343 (80TE) with biased differential (24 I/P & 32 O/P & RTD's)

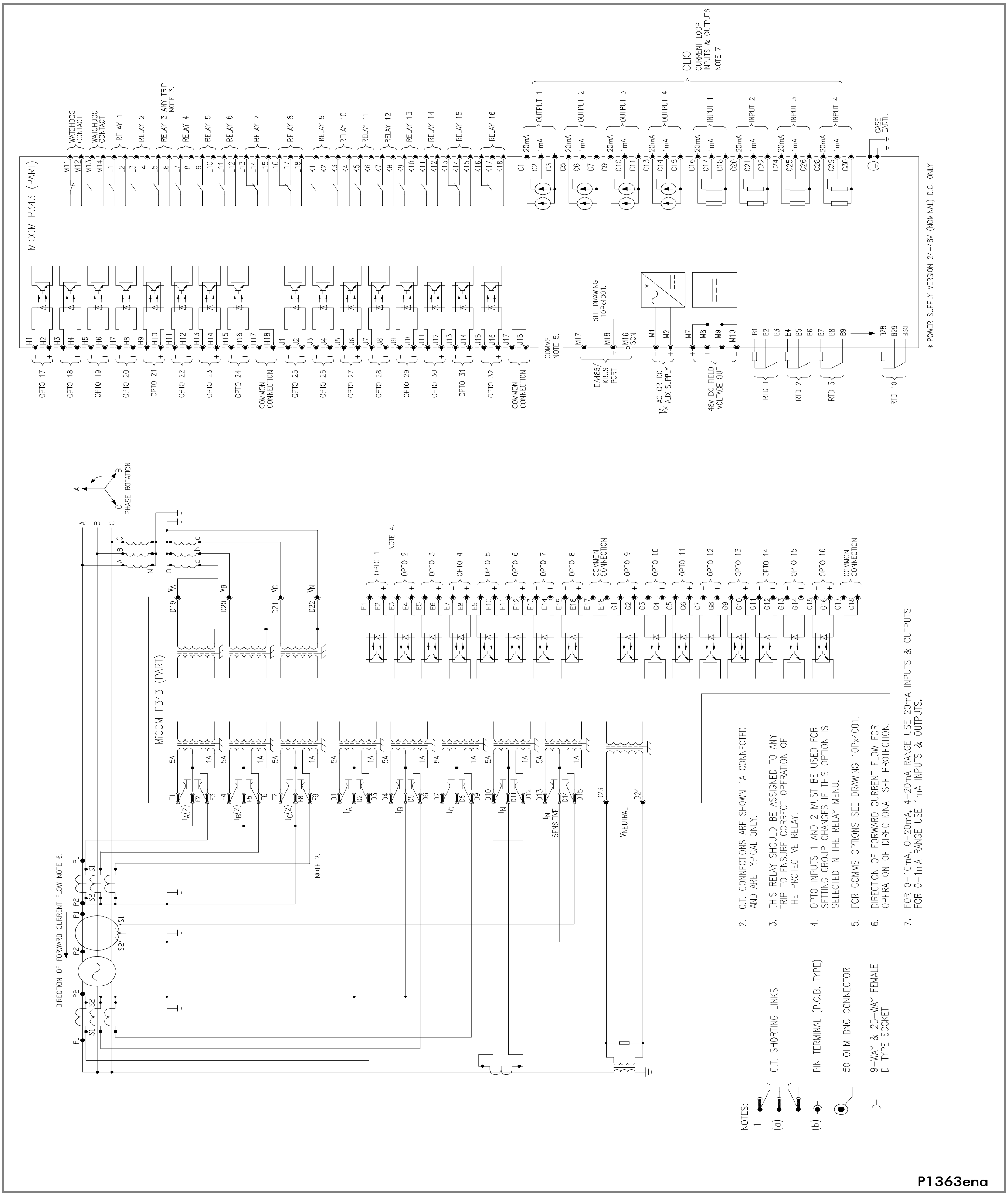


Figure 37 - P343 (80TE) with biased differential (32 I/P & 16 O/P & RTD & CLIO)

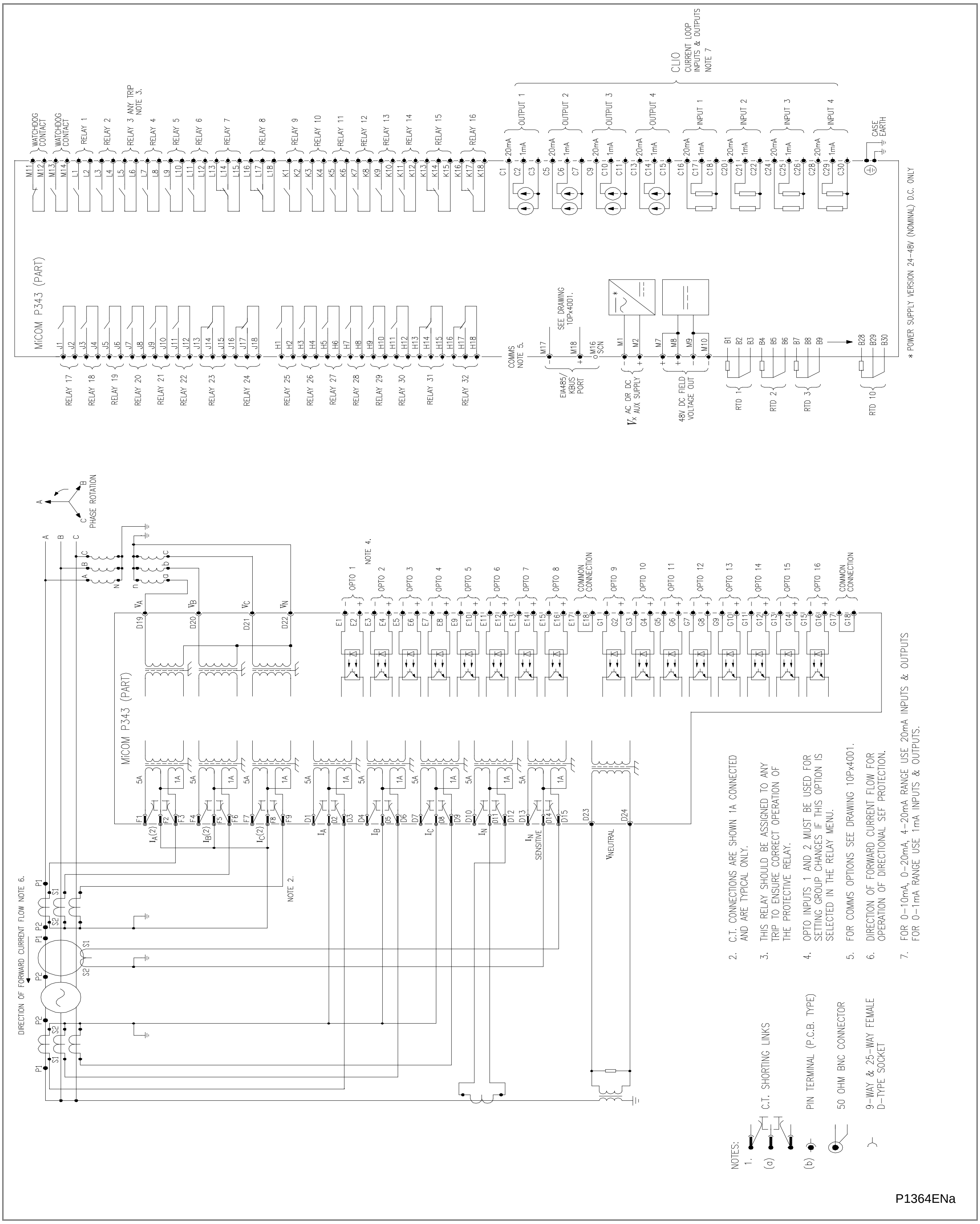


Figure 38 - P343 (80TE) with biased differential (16 I/P & 32 O/P & RTD & CLIO)

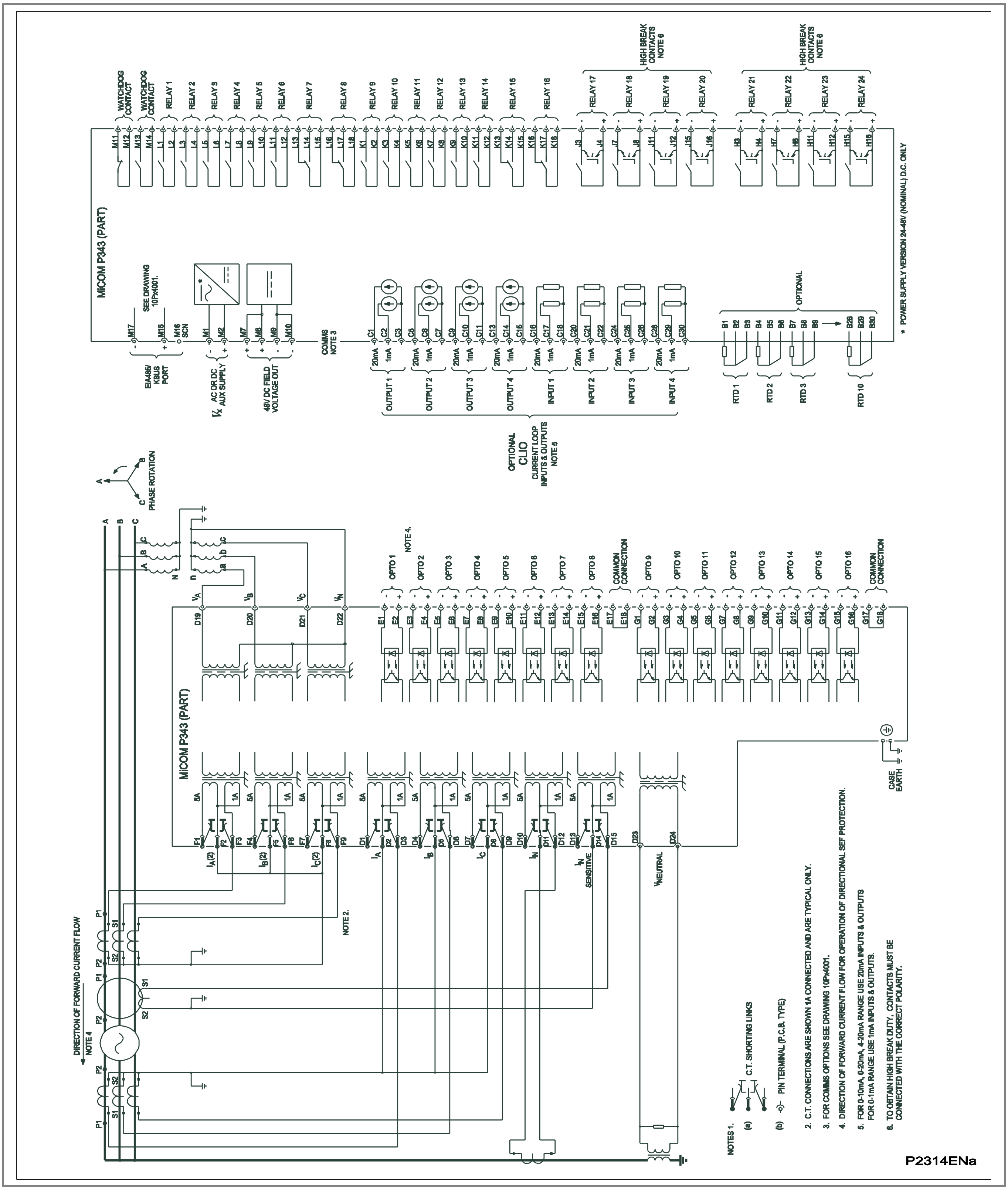


Figure 39 - P343 (80TE) with biased differential (16 I/P & 24 O/P (8 HB) & RTD's & CLIO)

Notes:

7 P344 CONNECTION DIAGRAMS

This section includes the following diagrams:

- Figure 40 - P344 (60TE) for biased generator-transformer differential (24 I/P & 24 O/P)
- Figure 41 - P344 (80TE) for biased differential and check synchronizing (24I/P & 24 O/P)
- Figure 42 - P344 (80TE) with biased differential and zero sequence voltage interturn (24 I/P & 24 O/P & RTD's & CLIO)
- Figure 43 - P344 (80TE) with biased differential and zero sequence voltage interturn (32 I/P & 24 O/P & RTD's)
- Figure 44 - P344 (80TE) with biased differential and zero sequence voltage interturn (24 I/P & 32 O/P & RTD's)
- Figure 45 - P344 (80TE) with biased differential and zero sequence voltage interturn (32 I/P & 16 O/P & RTD's & CLIO)
- Figure 46 - P344 (80TE) with biased differential and zero sequence voltage interturn (16 I/P & 32 O/P & RTD's & CLIO)
- Figure 47 - P344 (80TE) with biased differential and zero sequence voltage interturn (24 I/P & 20 O/P (4HB) & RTD's & CLIO)
- Figure 48 - P344 (80TE) with biased differential and zero sequence voltage interturn (16 I/P & 24 O/P (8HB) & RTD's & CLIO)

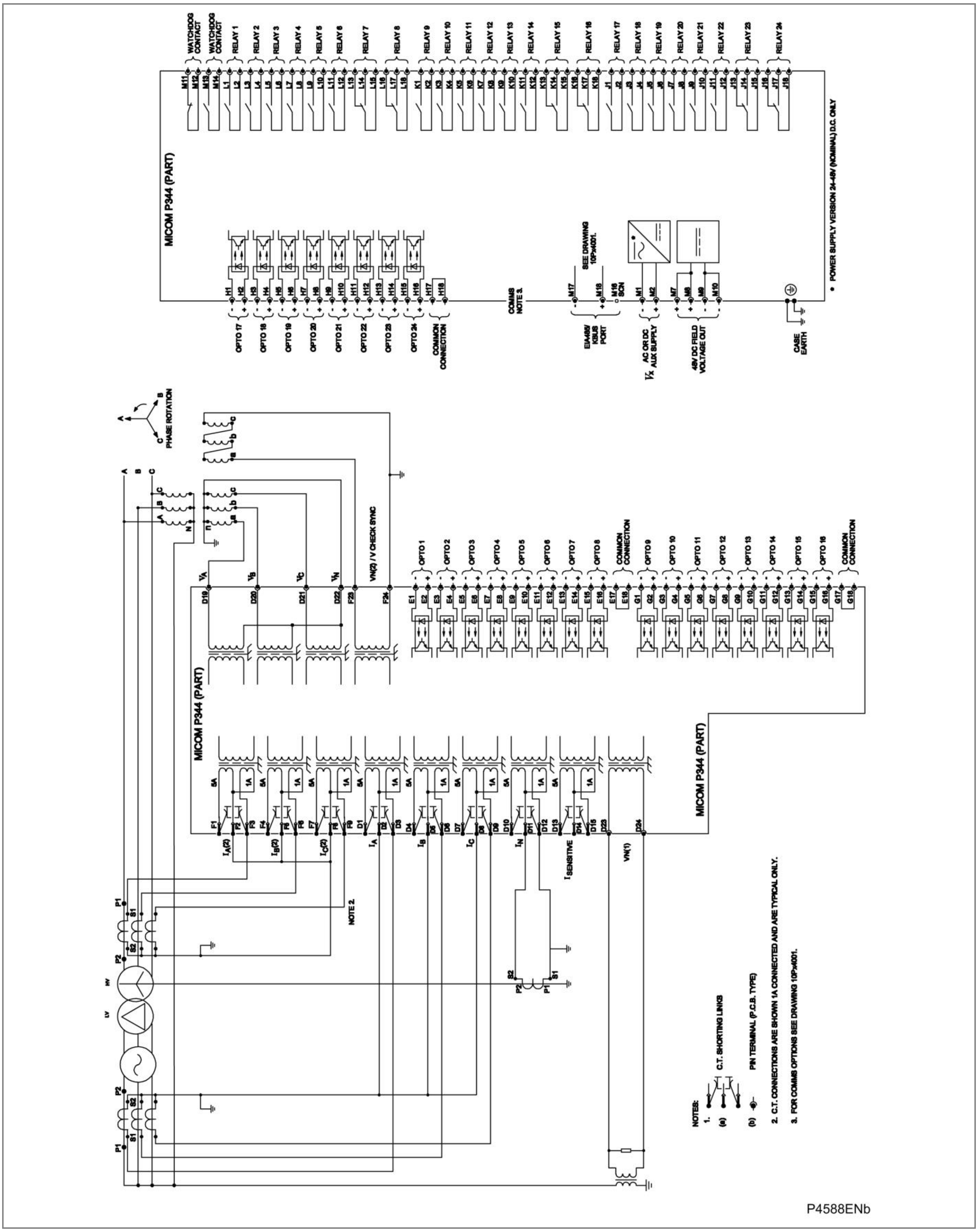


Figure 40 - P344 (60TE) for biased generator-transformer differential (24 I/P & 24 O/P)

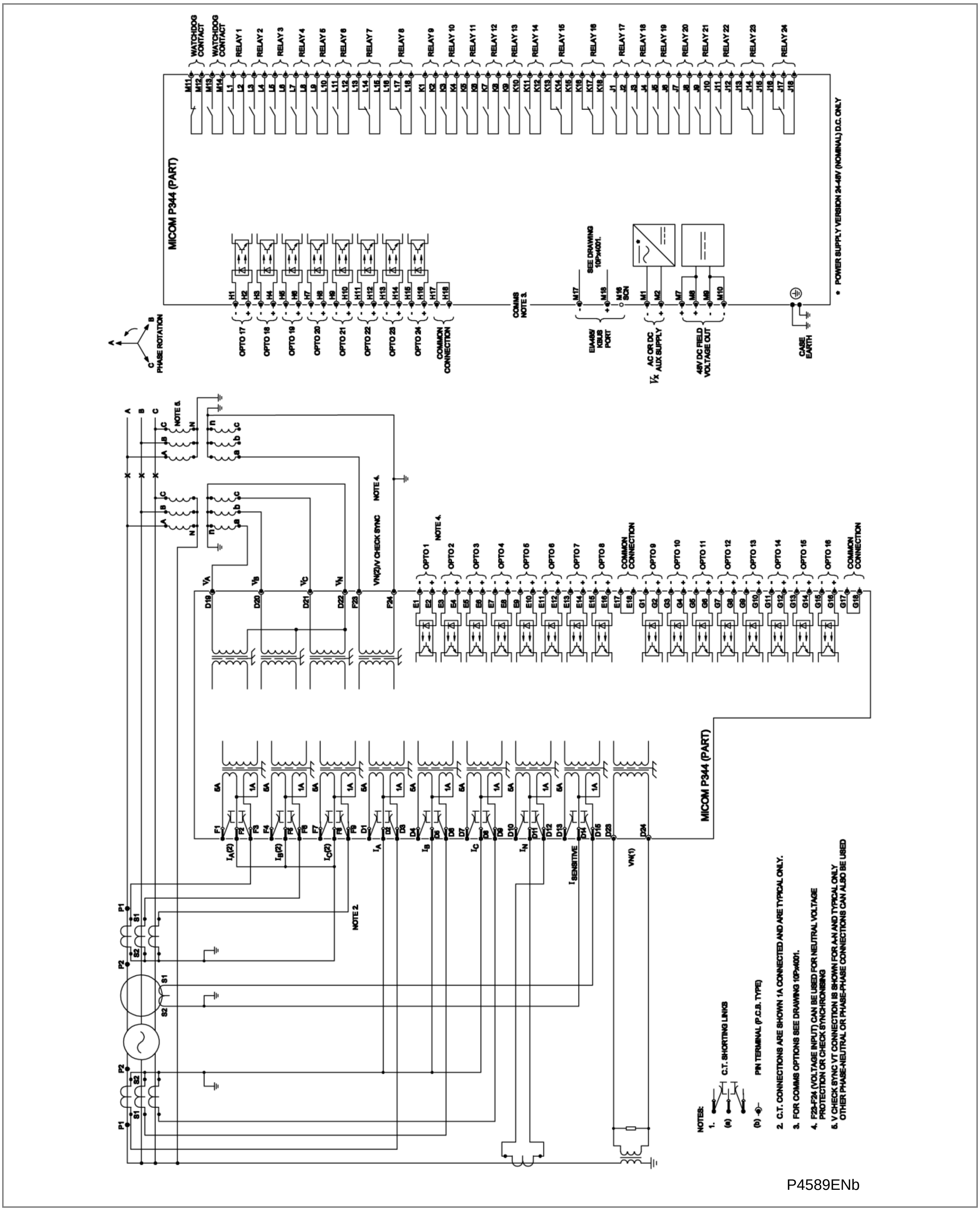


Figure 41 - P344 (80TE) for biased differential and check synchronizing (24I/P & 24 O/P)

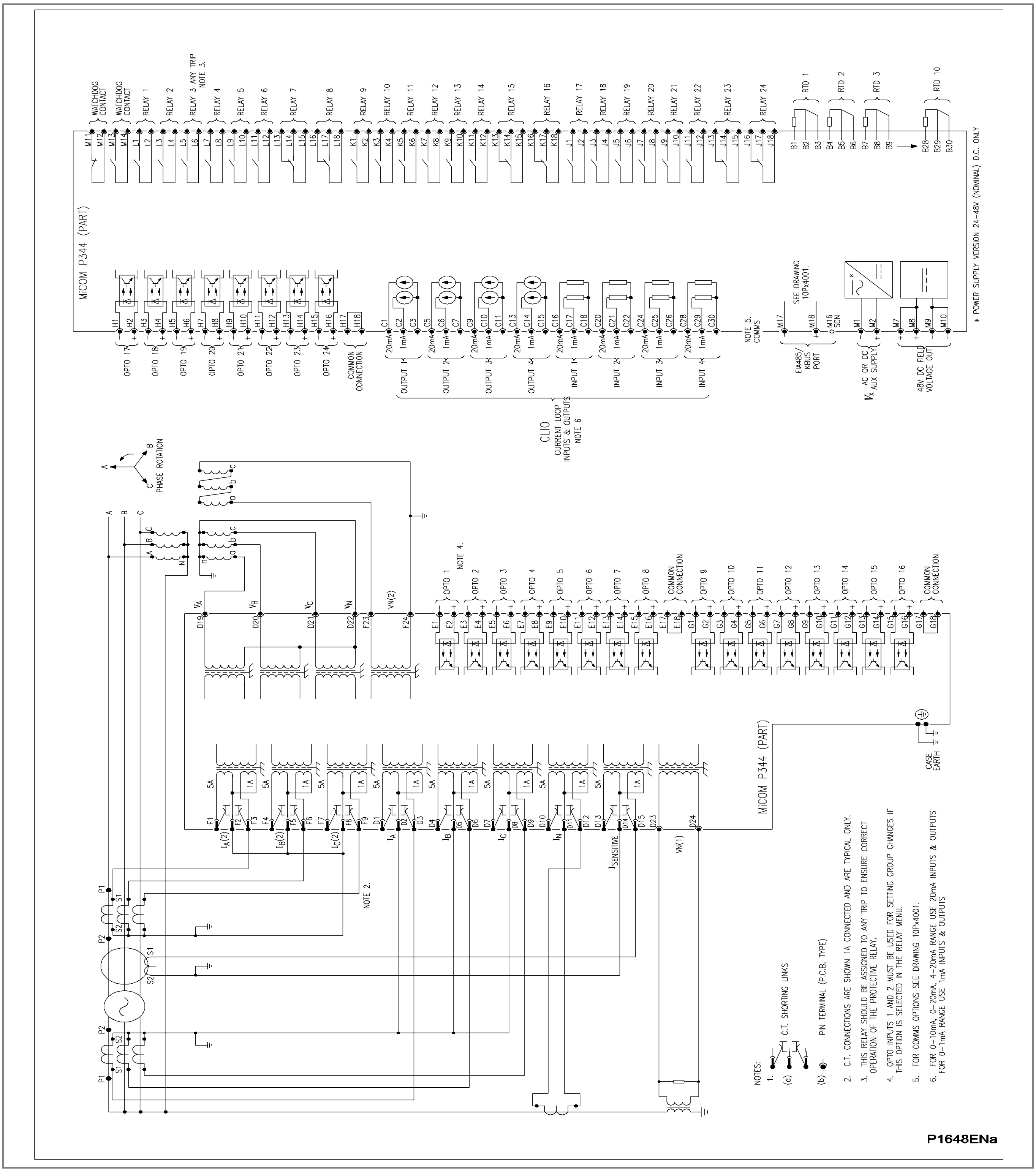


Figure 42 - P344 (80TE) with biased differential and zero sequence voltage interturn (24 I/P & 24 O/P & RTD's & CLIO)

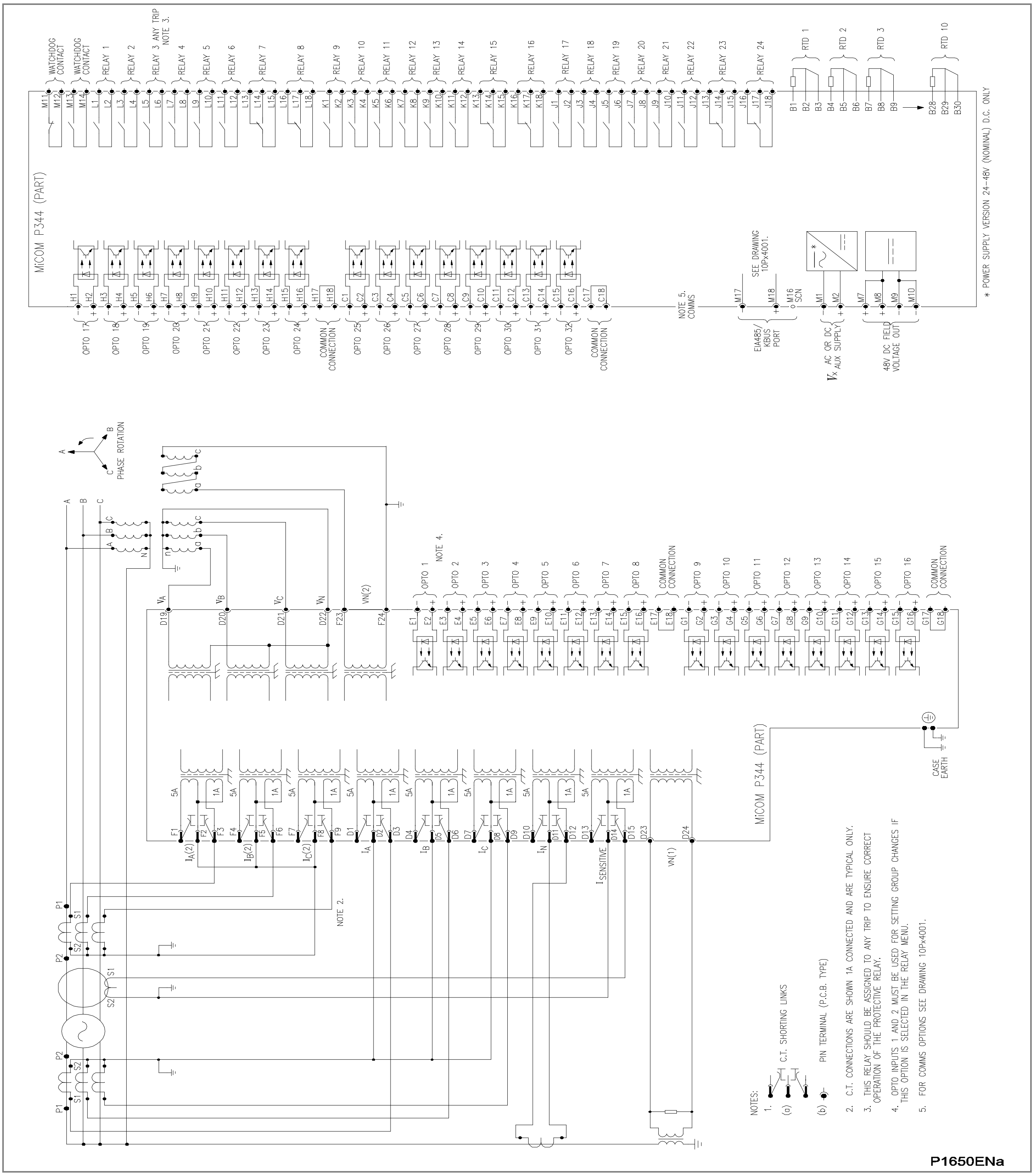


Figure 43 - P344 (80TE) with biased differential and zero sequence voltage interturn (32 I/P & 24 O/P & RTD's)

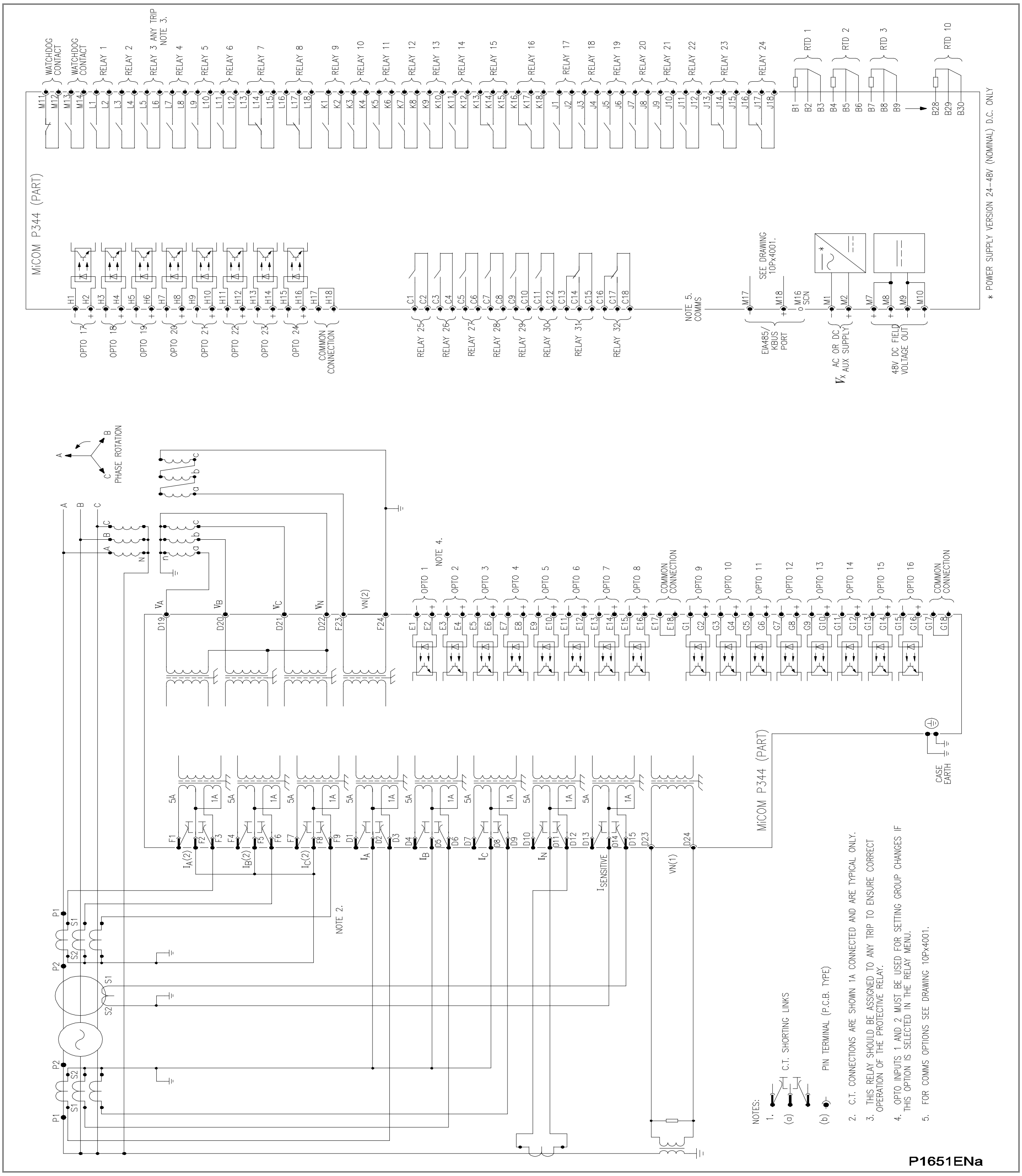


Figure 44 - P344 (80TE) with biased differential and zero sequence voltage interturn (24 I/P & 32 O/P & RTD’s)

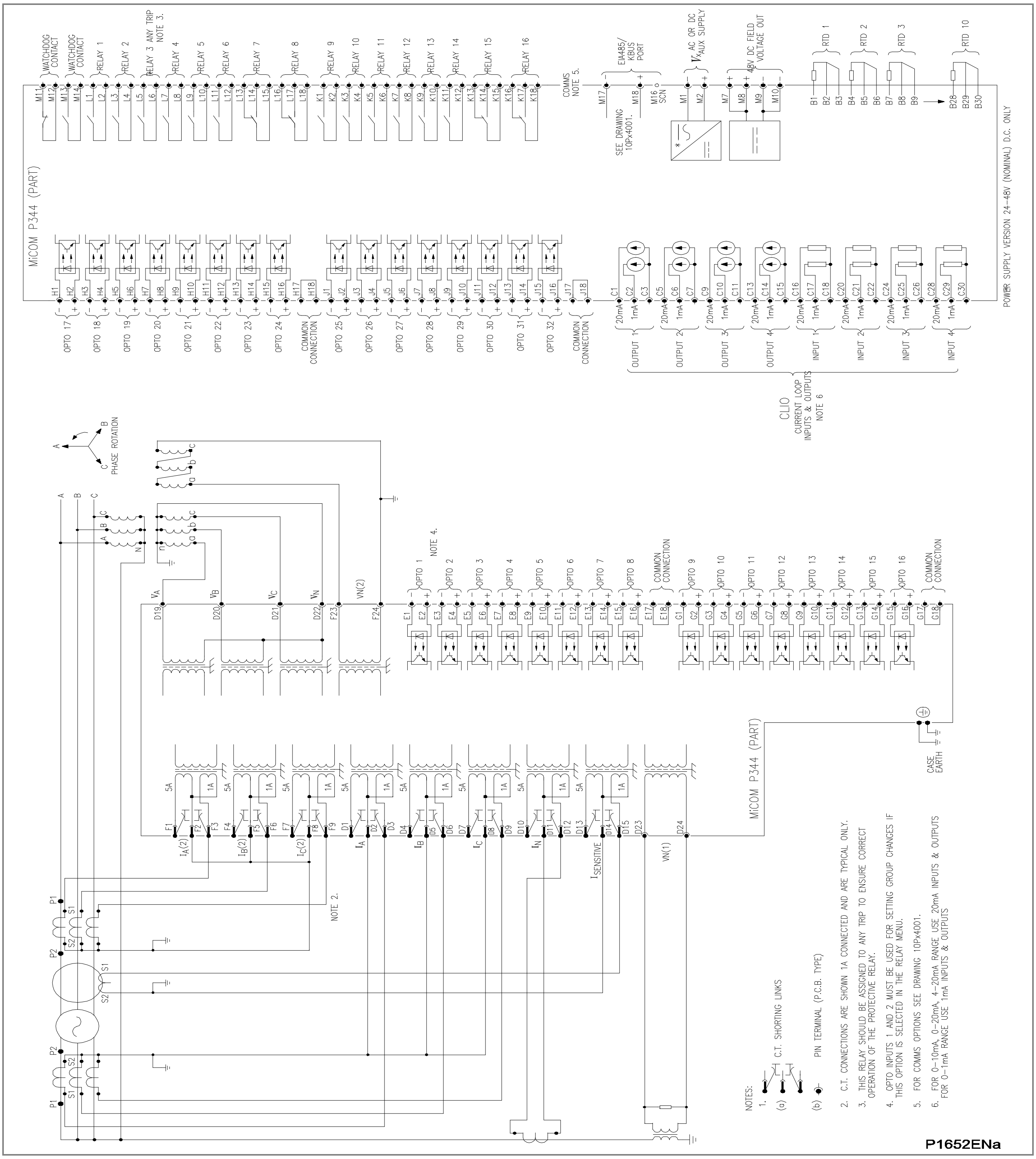


Figure 45 - P344 (80TE) with biased differential and zero sequence voltage interturn (32 I/P & 16 O/P & RTD's & CLIO)

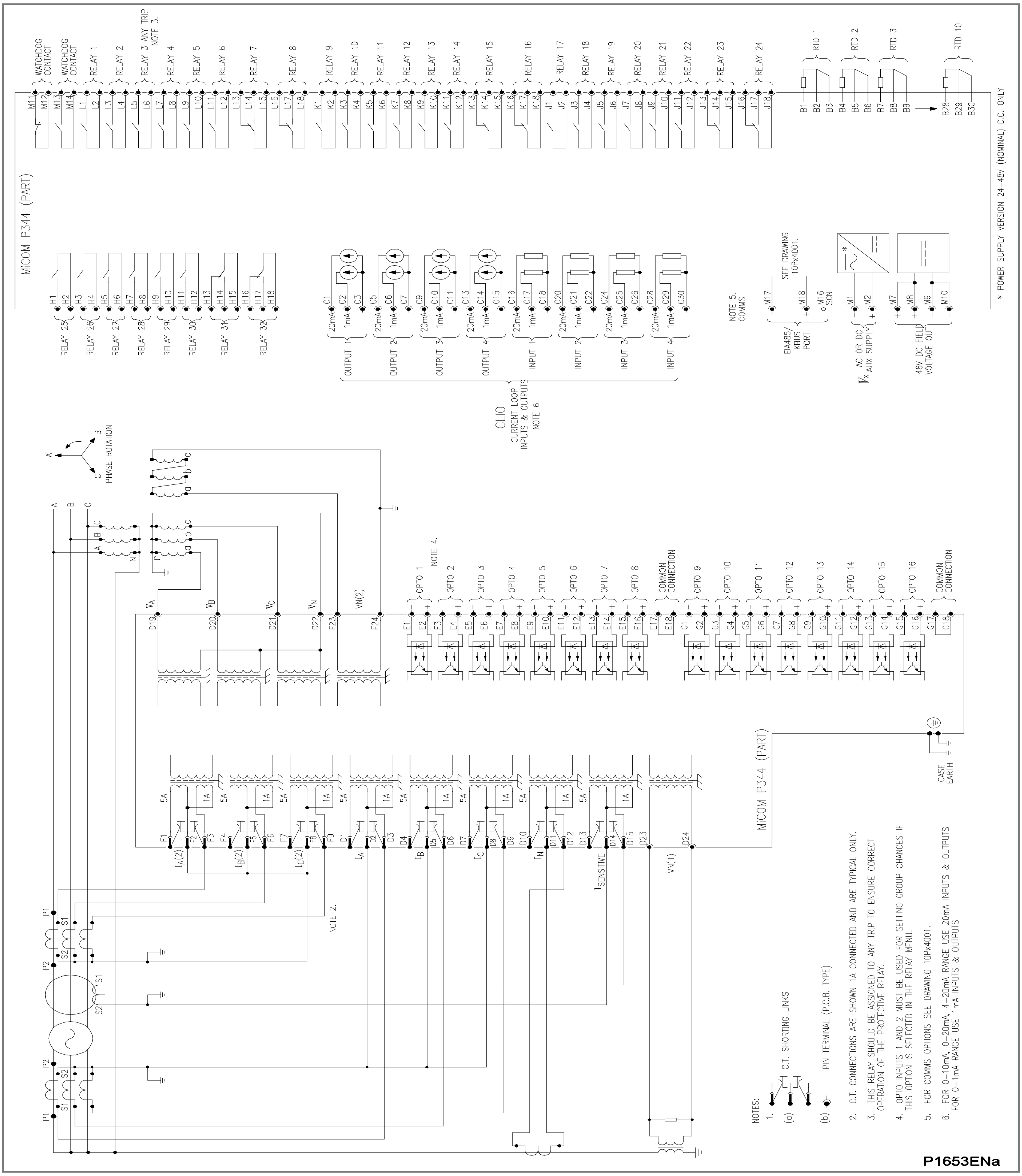


Figure 46 - P344 (80TE) with biased differential and zero sequence voltage interturn (16 I/P & 32 O/P & RTD’s & CLIO)

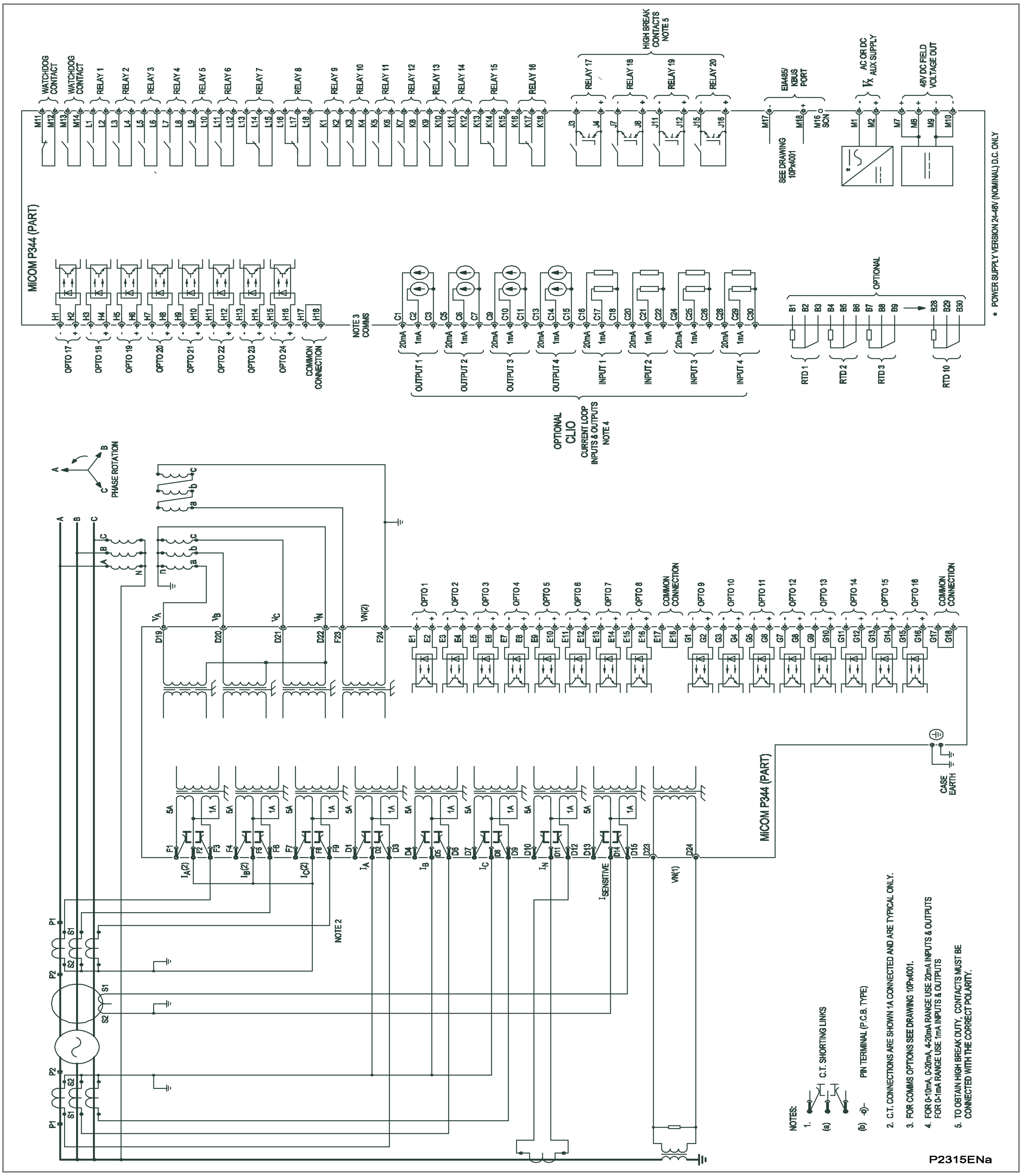


Figure 47 - P344 (80TE) with biased differential and zero sequence voltage interturn (24 I/P & 20 O/P (4HB) & RTD's & CLIO)

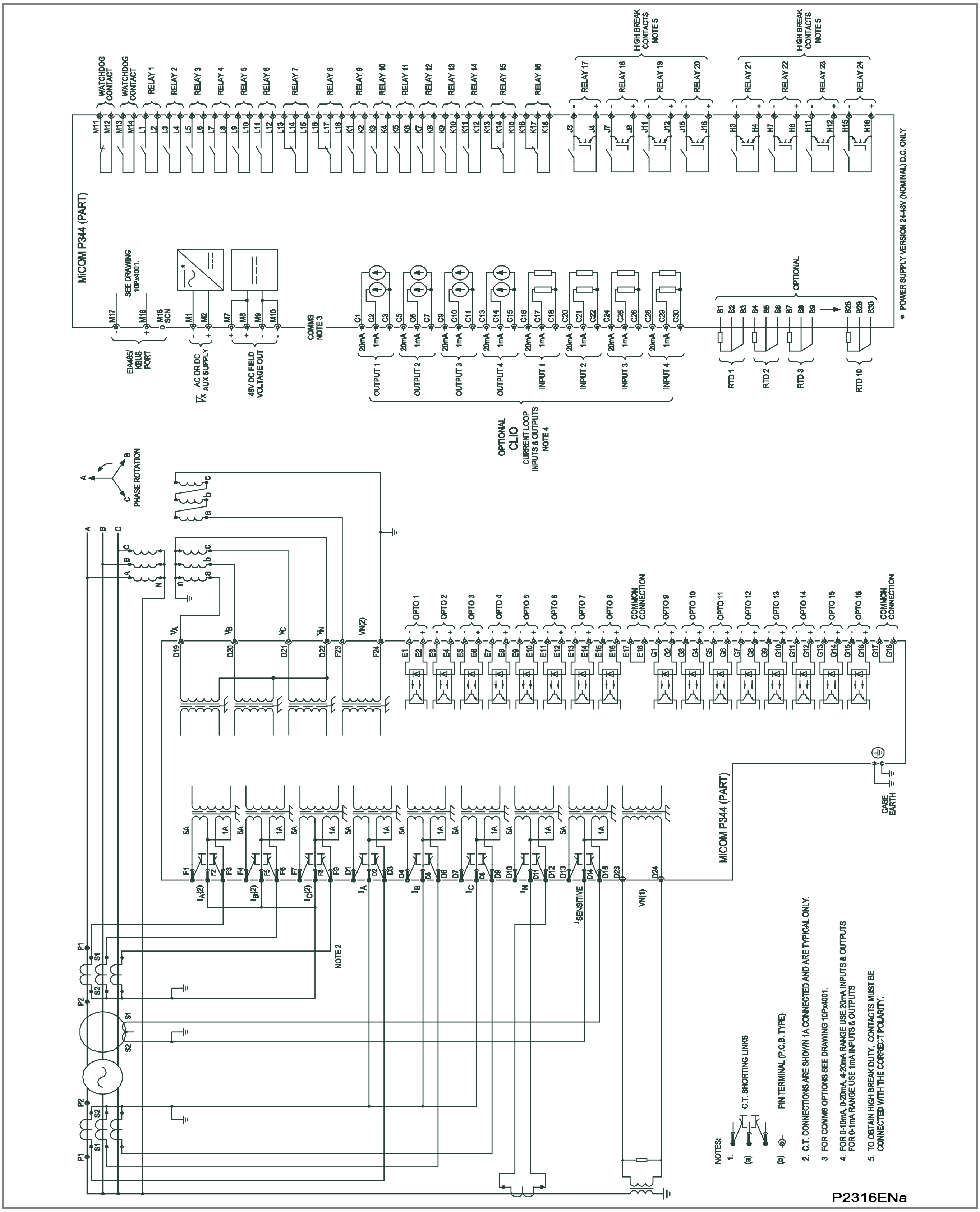


Figure 48 - P344 (80TE) with biased differential and zero sequence voltage interturn (16 I/P & 24 O/P (8HB) & RTD's & CLIO)

8 P345 CONNECTION DIAGRAMS

This section contains the following digrams:

- Figure 49 - P345 (80TE) for biased generator-transformer differential & check synchronizing (24 I/P & 24 O/P & CLIO & RTD)
- Figure 50 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection & check synchronising (24 I/P & 24 O/P & CLIO & RTD)
- Figure 51 - P345 (80TE) with 100% stator earth fault protection via terminal earthing transformer broken delta with secondary loading resistor (24 I/P & 24 O/P & CLIO & RTD)
- Figure 52 - P345 (80TE) with 100% stator earth fault protection via neutral earthing transformer with secondary loading resistor (24 I/P & 24 O/P & CLIO & RTD)
- Figure 53 - P345 (80TE) with 100% stator earth fault protection via neutral earthing transformer with primary loading resistor (24 I/P & 24 O/P & CLIO & RTD)
- Figure 54 - P345 (80TE) 100% stator earth fault via low frequency injection configurations
- Figure 55 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (24 I/P & 32 O/P & RTD)
- Figure 56 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (32 I/P & 24 O/P & RTD)
- Figure 57 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (32 I/P & 16 O/P & CLIO & RTD)
- Figure 58 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (16 I/P & 32 O/P & CLIO & RTD)
- Figure 59 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (24 I/P & 20 O/P (4HB) & CLIO & RTD)
- Figure 60 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (16 I/P & 24 O/P (8HB) & CLIO & RTD)

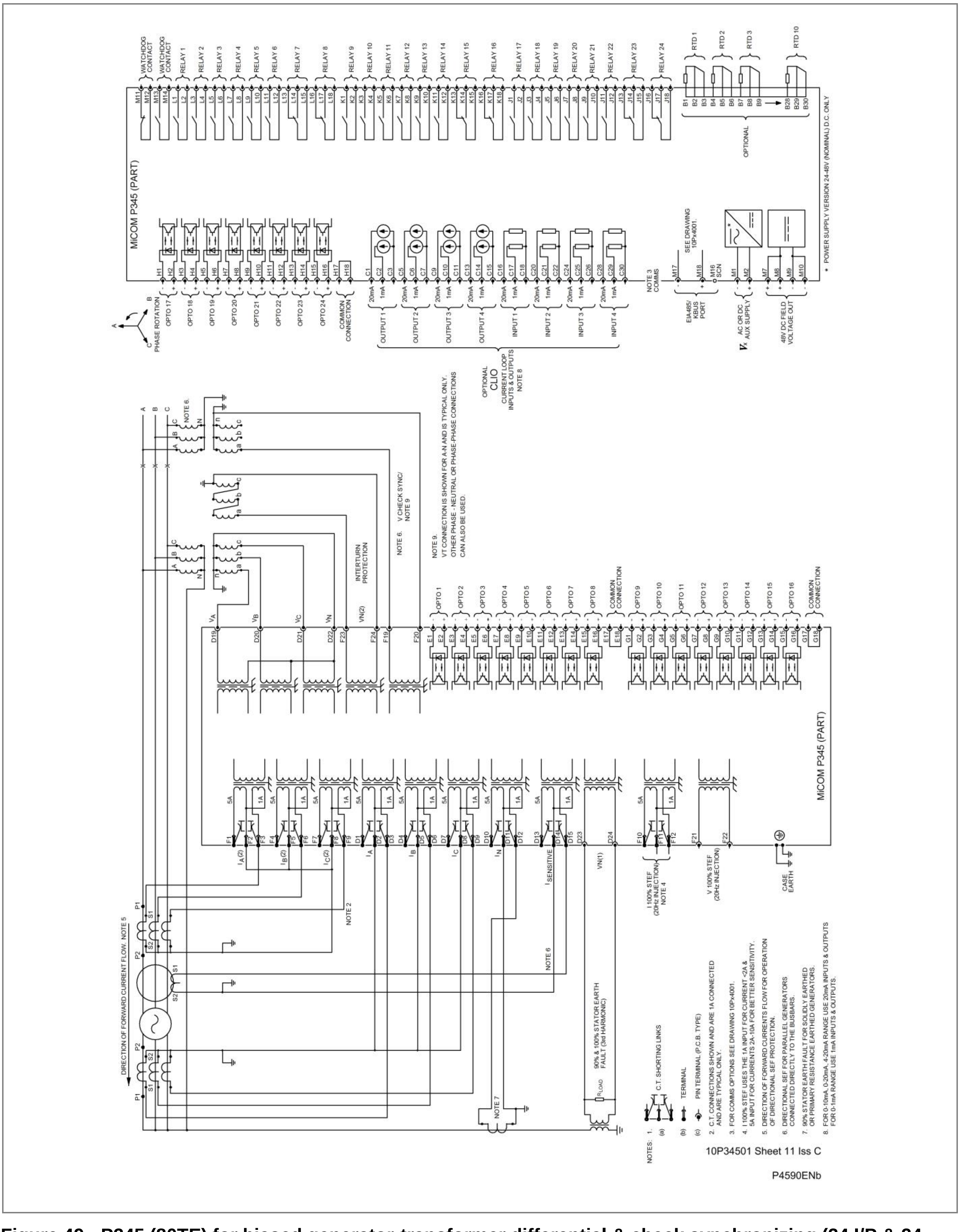


Figure 49 - P345 (80TE) for biased generator-transformer differential & check synchronizing (24 I/P & 24 O/P & CLIO & RTD)

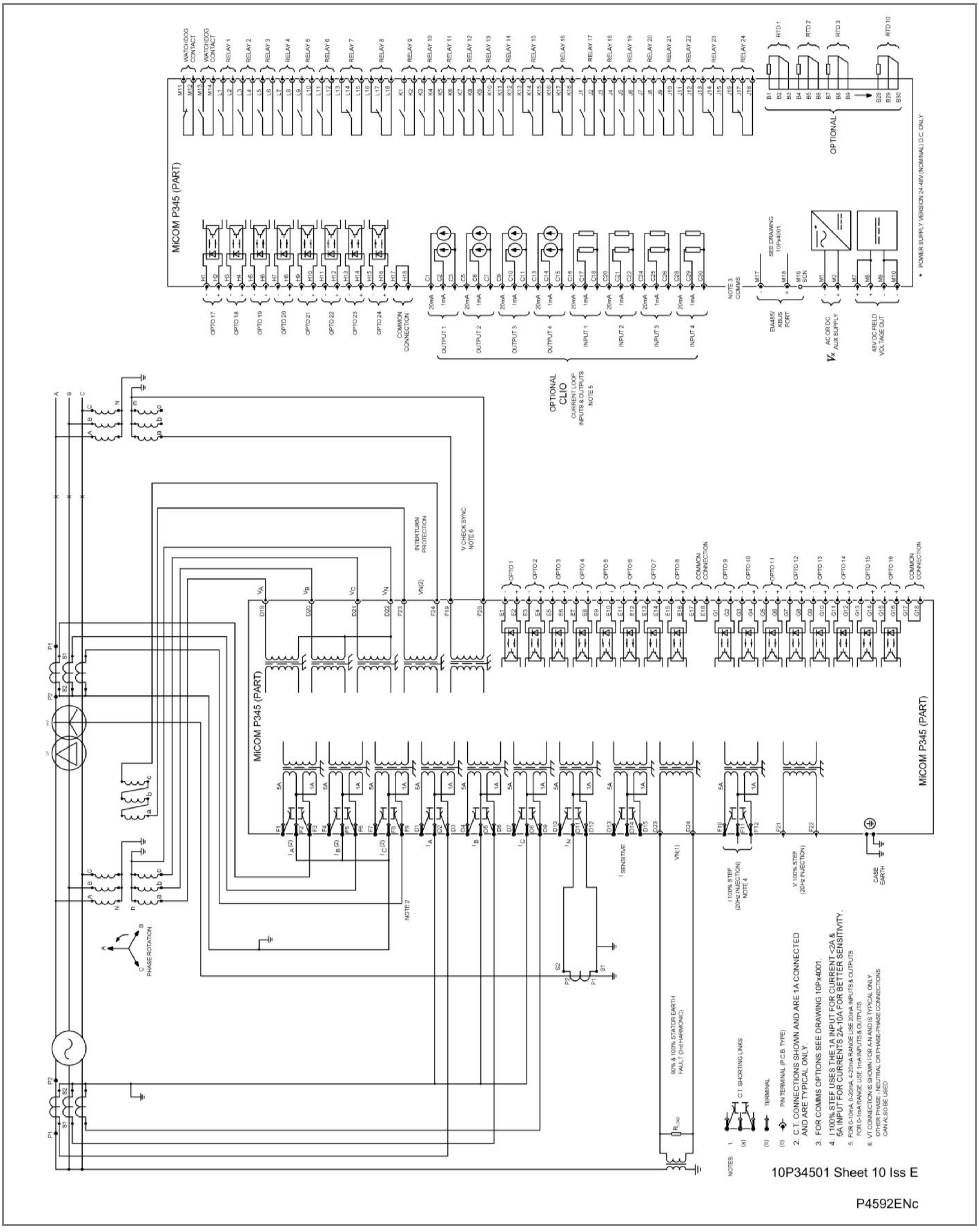


Figure 50 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection & check synchronising (24 I/P & 24 O/P & CLIO & RTD)

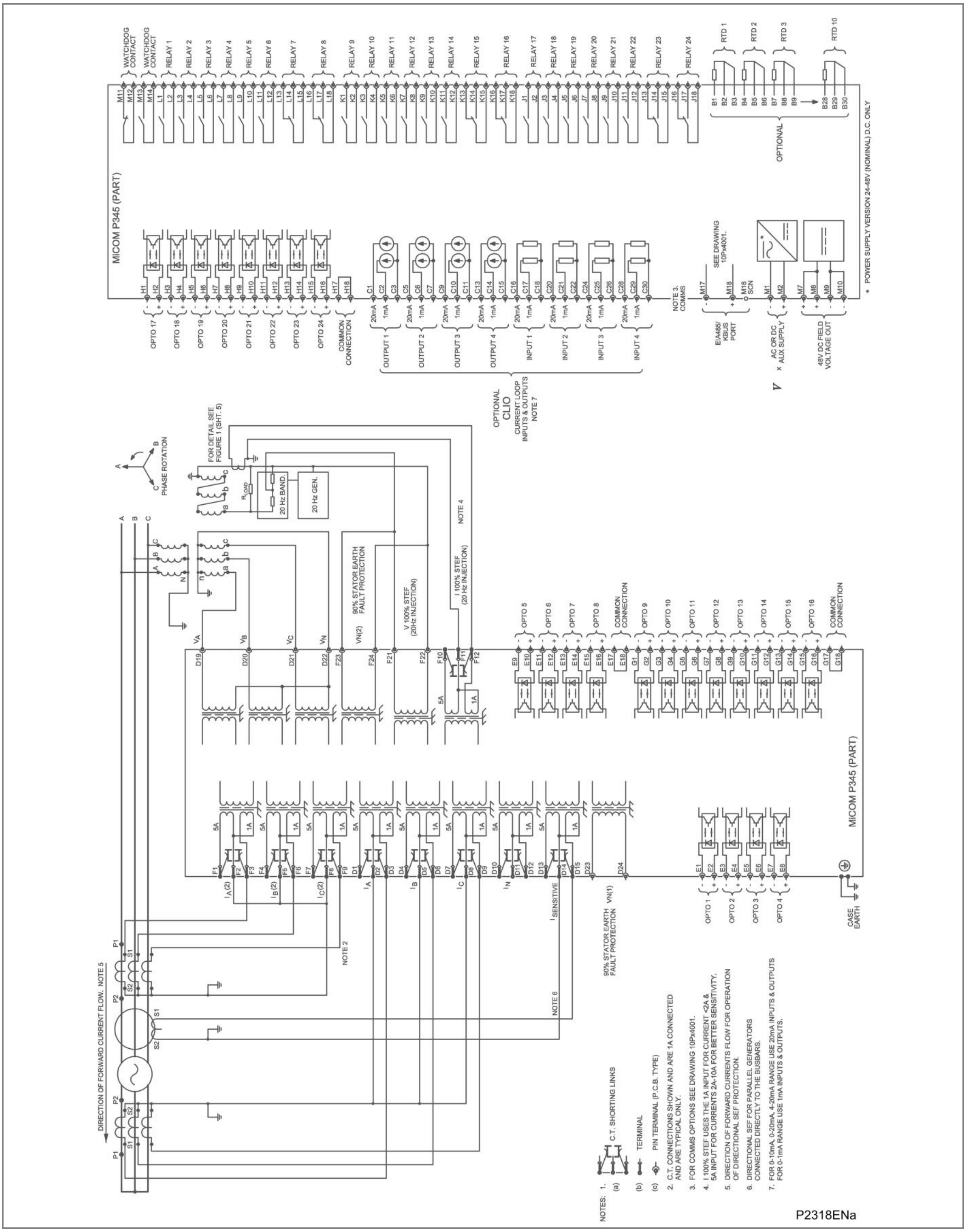


Figure 51 - P345 (80TE) with 100% stator earth fault protection via terminal earthing transformer broken delta with secondary loading resistor (24 I/P & 24 O/P & CLIO & RTD)

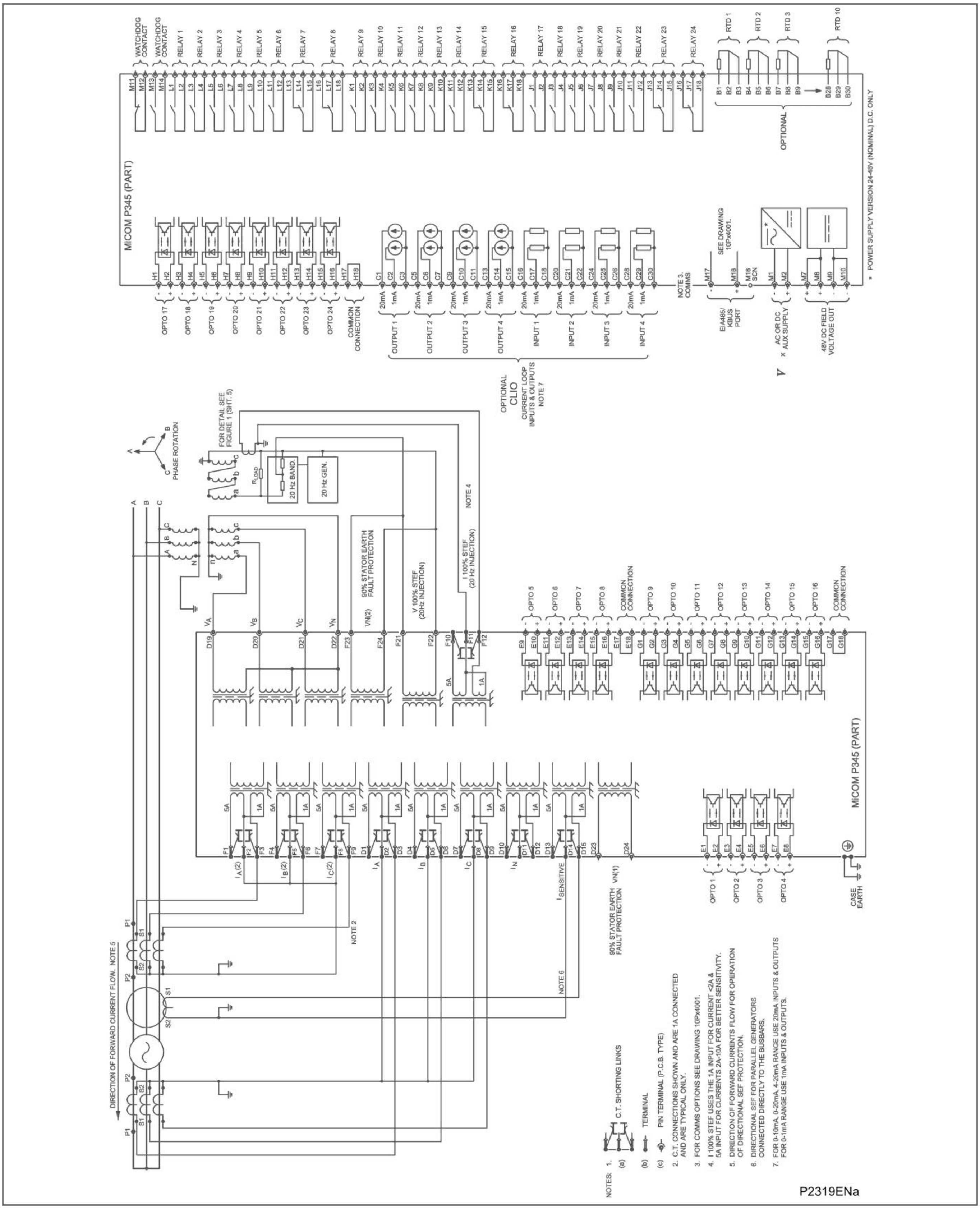


Figure 52 - P345 (80TE) with 100% stator earth fault protection via neutral earthing transformer with secondary loading resistor (24 I/P & 24 O/P & CLIO & RTD)

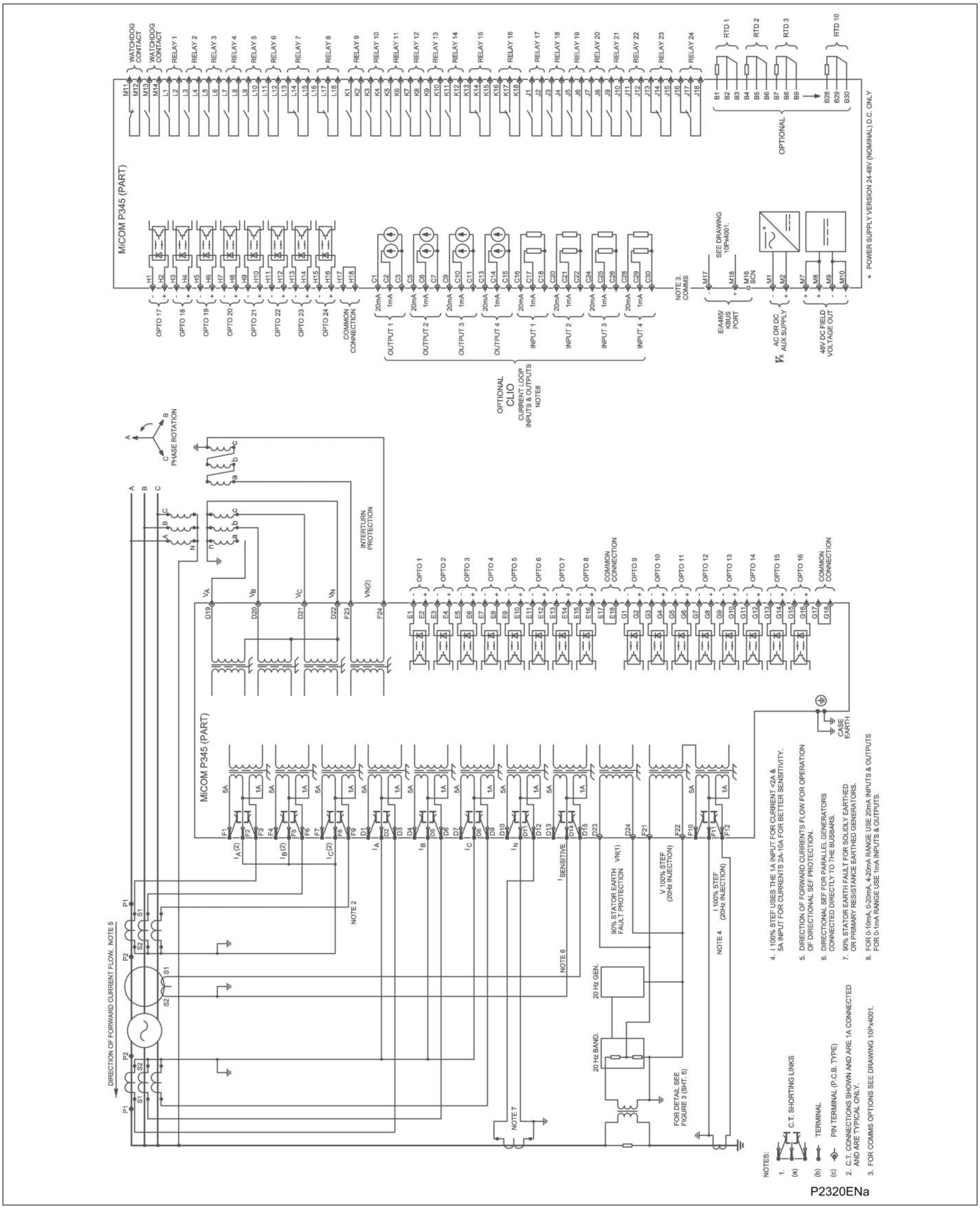


Figure 53 - P345 (80TE) with 100% stator earth fault protection via neutral earthing transformer with primary loading resistor (24 I/P & 24 O/P & CLIO & RTD)

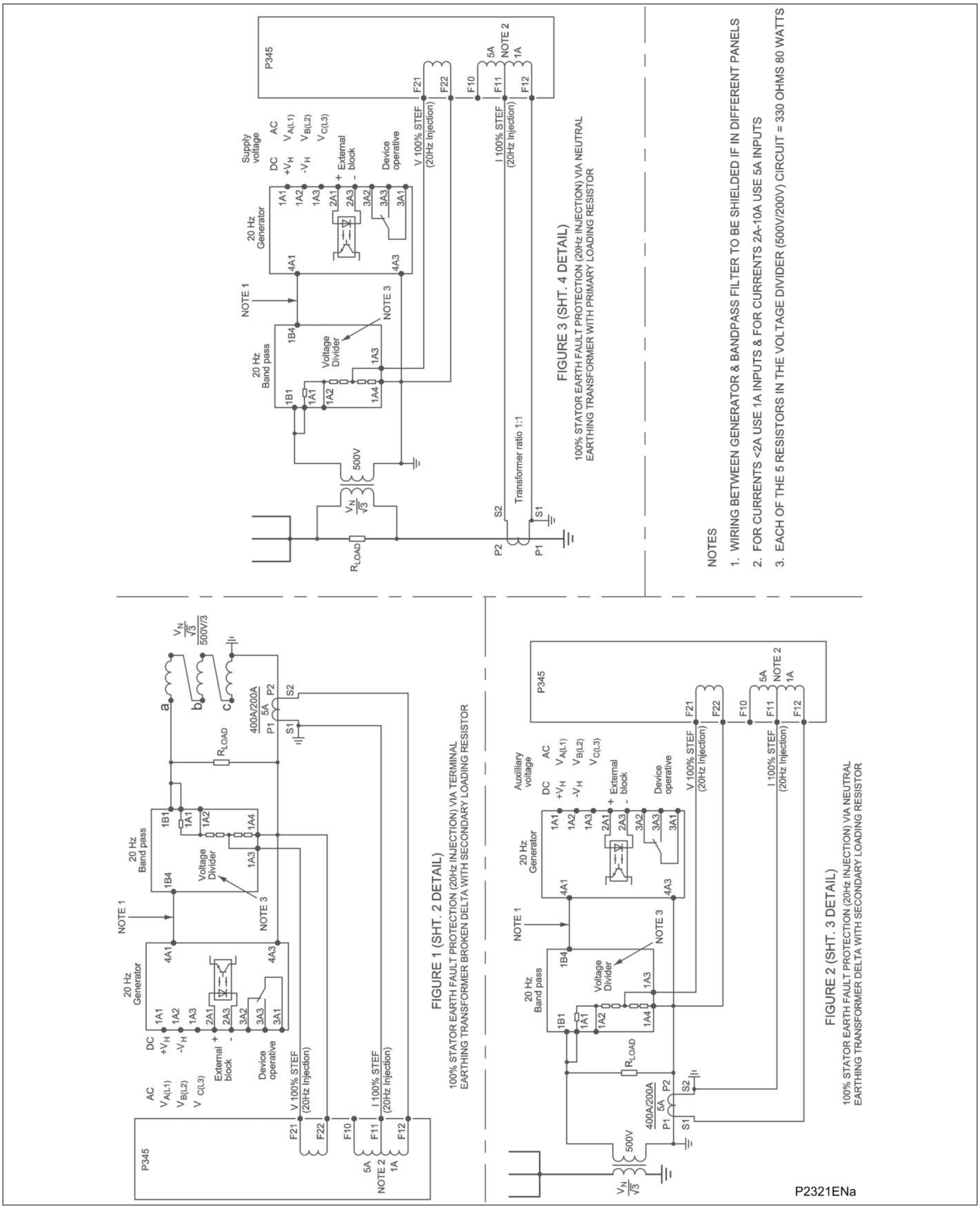


Figure 54 - P345 (80TE) 100% stator earth fault via low frequency injection configurations

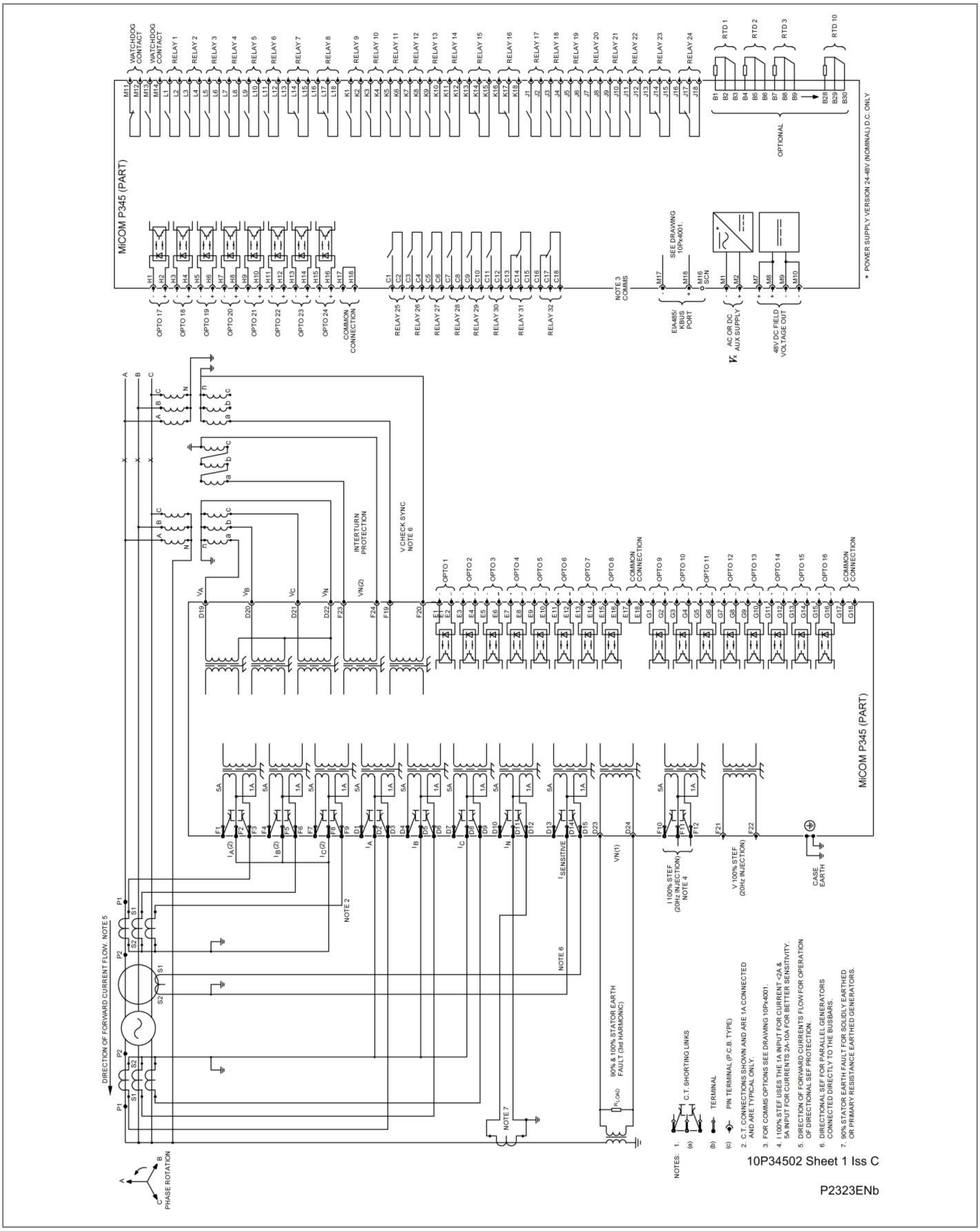


Figure 55 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (24 I/P & 32 O/P & RTD)

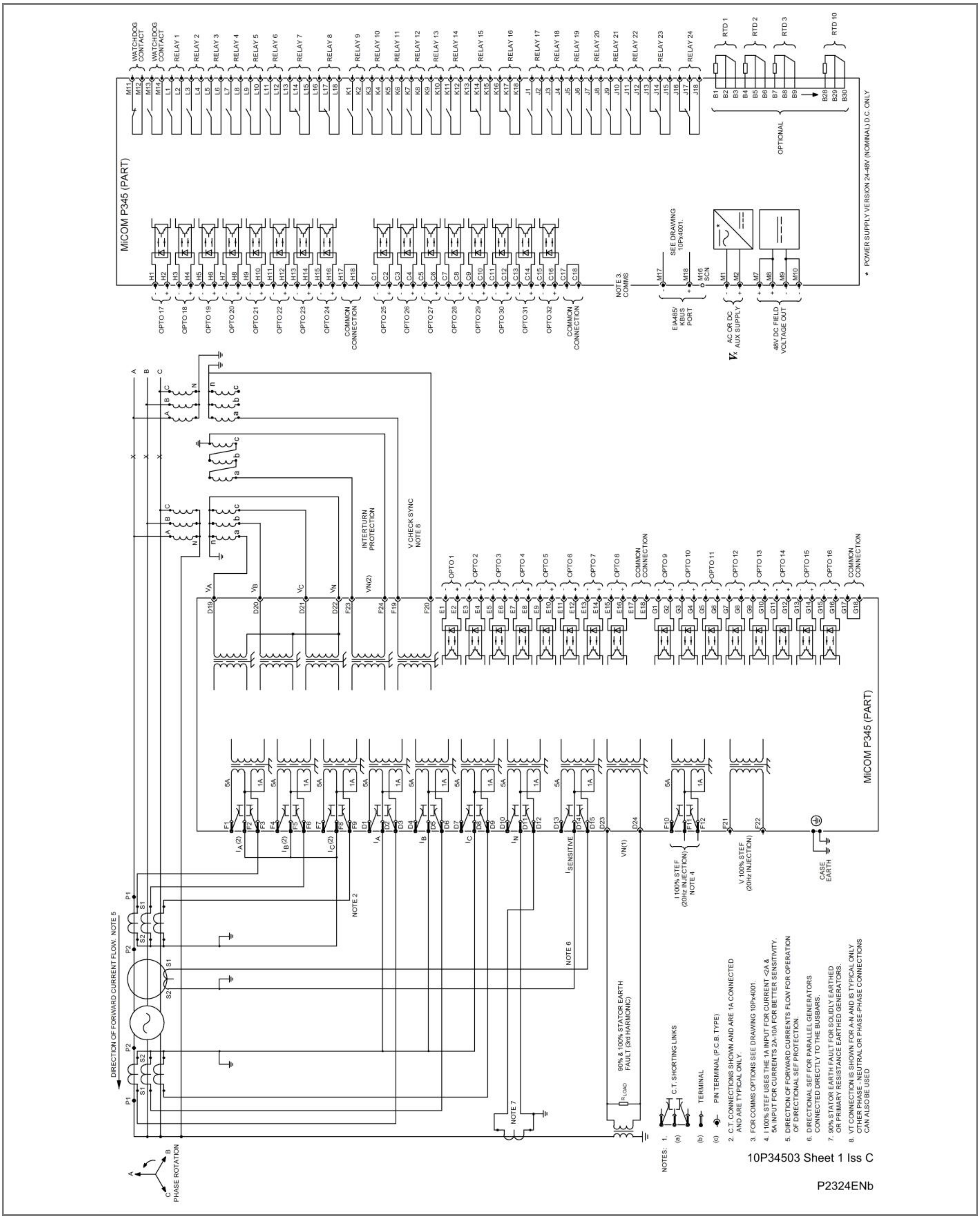


Figure 56 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (32 I/P & 24 O/P & RTD)

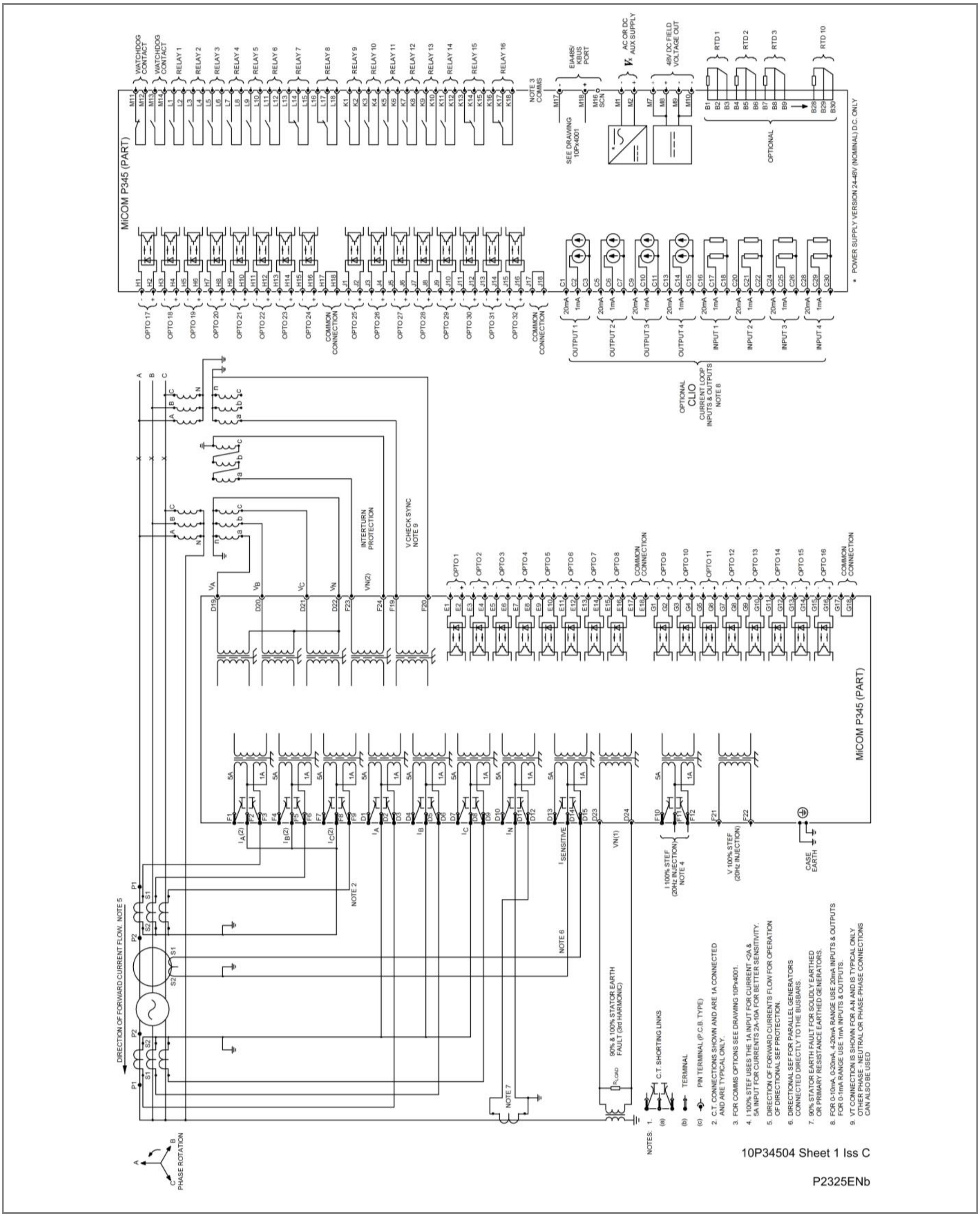


Figure 57 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (32 I/P & 16 O/P & CLIO & RTD)

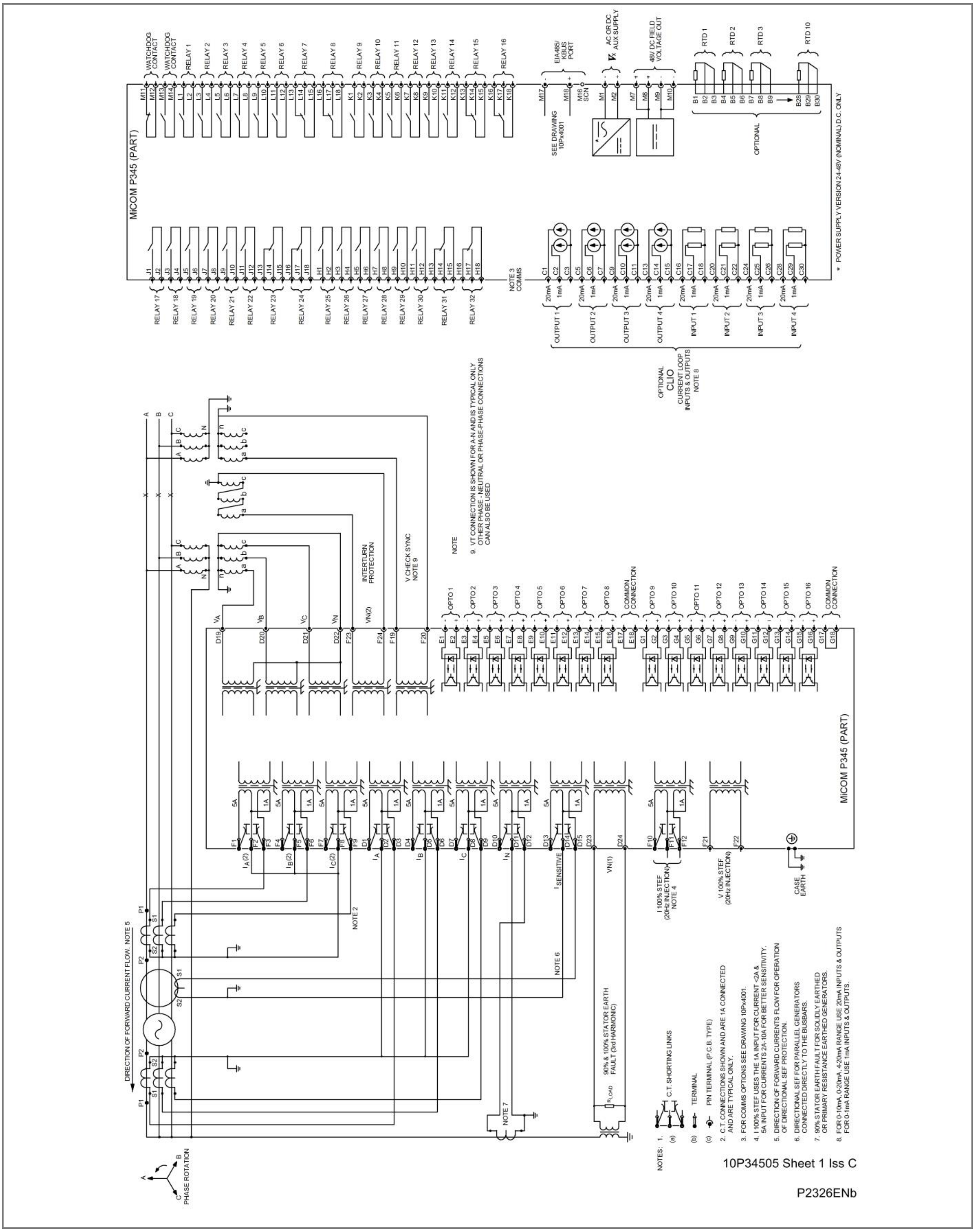


Figure 58 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (16 I/P & 32 O/P & CLIO & RTD)

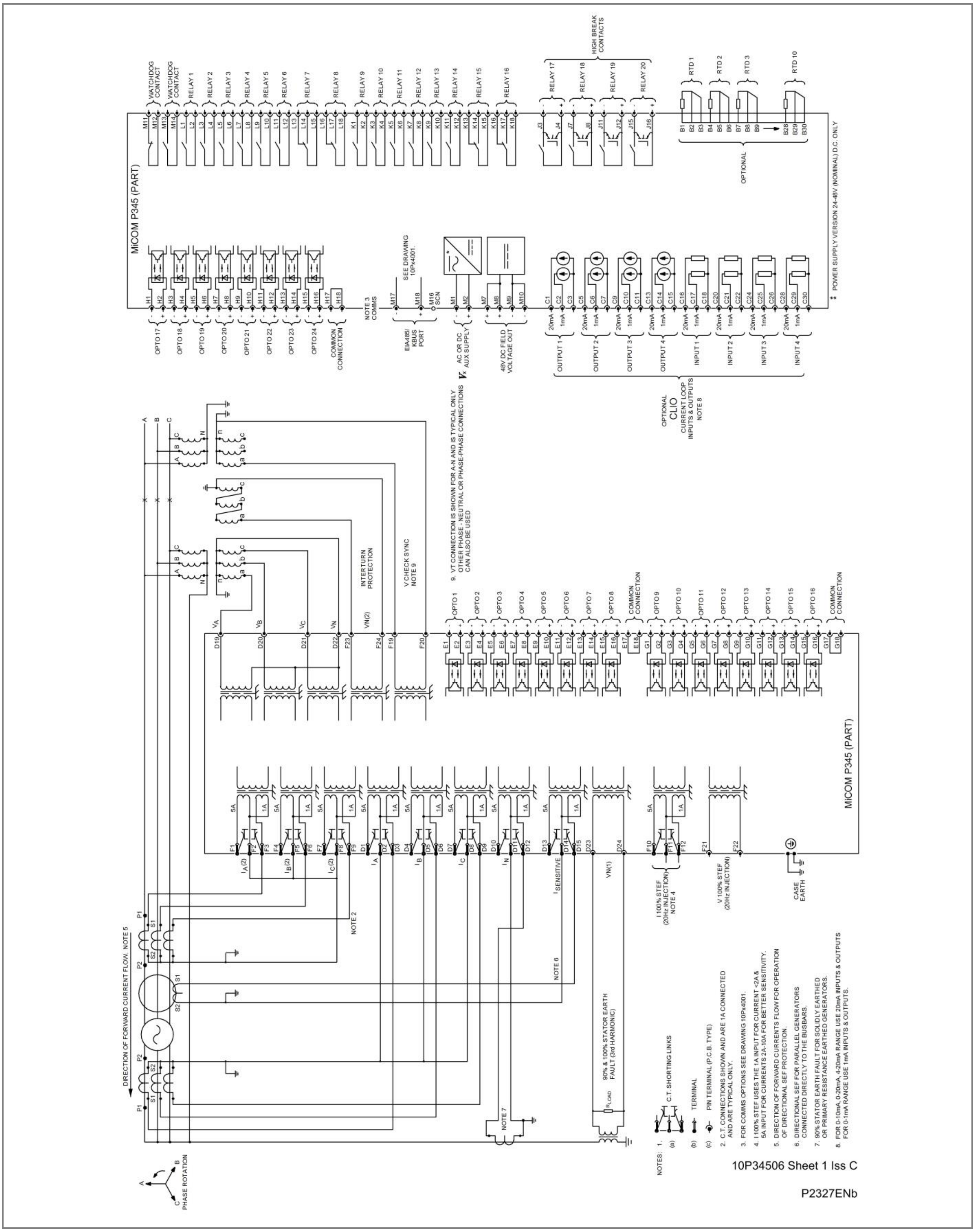


Figure 59 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (24 I/P & 20 O/P (4HB) & CLIO & RTD)

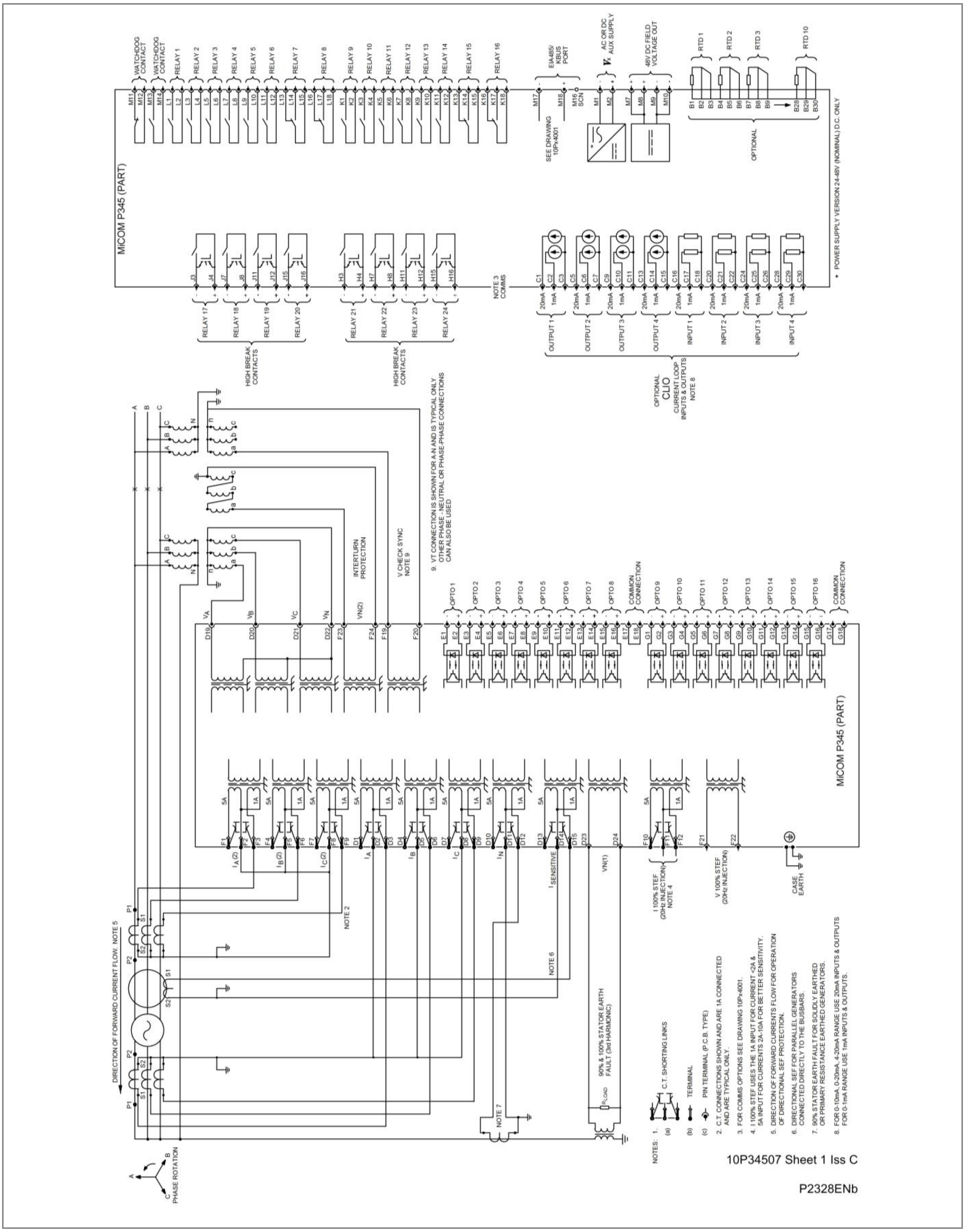
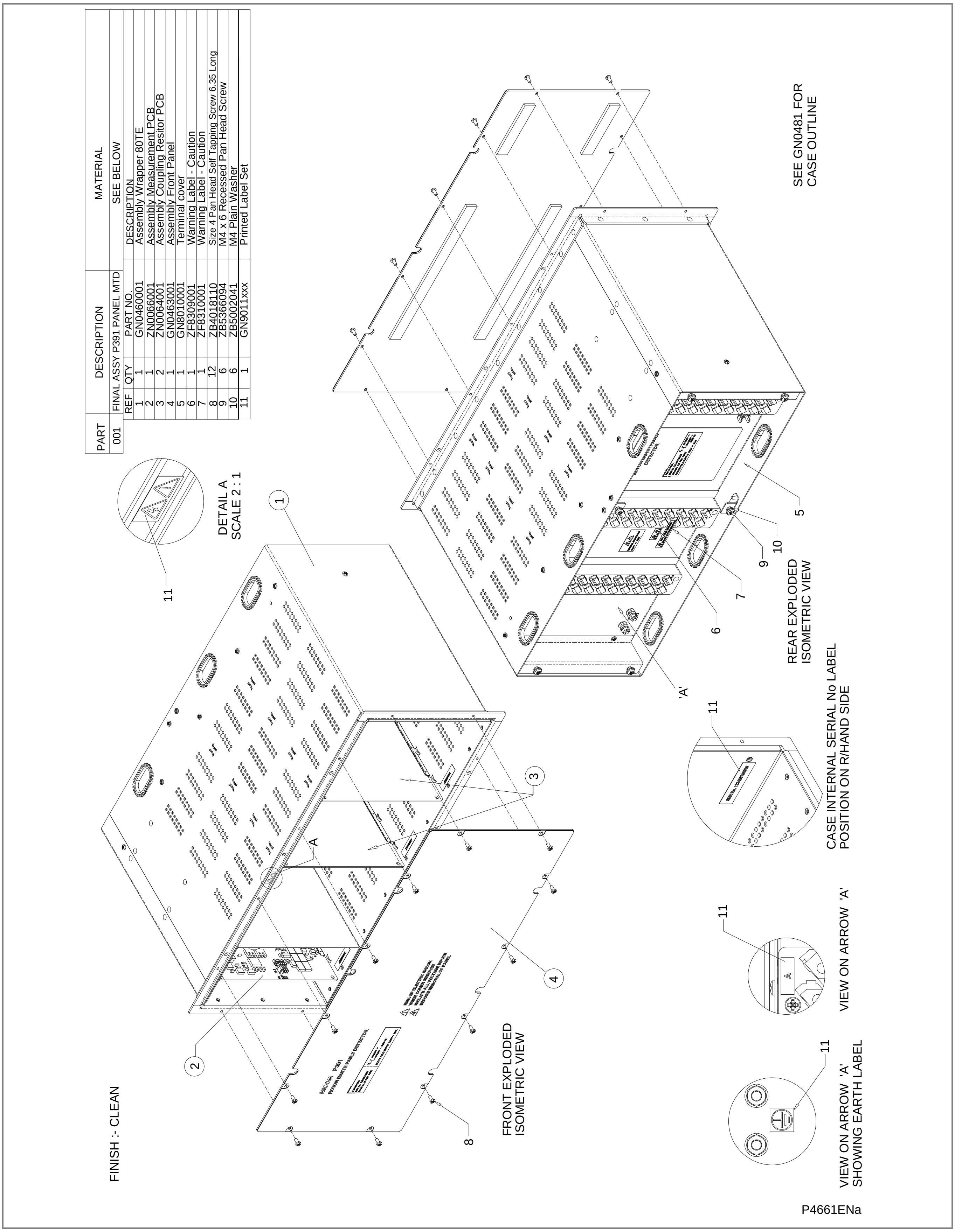


Figure 60 - P345 (80TE) with 90% & 100% (3rd Harmonic) stator earth fault & interturn protection (16 I/P & 24 O/P (8HB) & CLIO & RTD)

Notes:

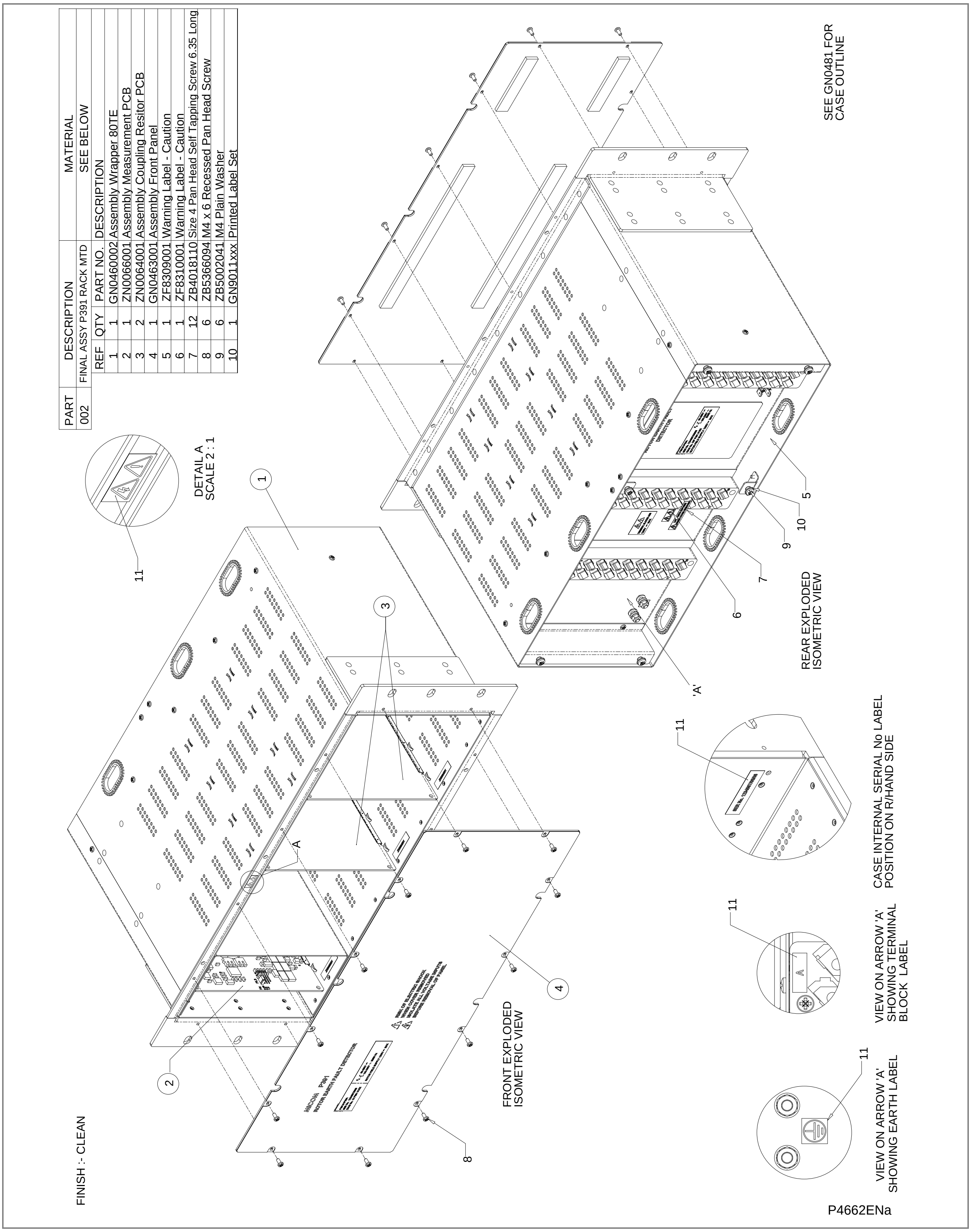
9 ASSEMBLY DRAWINGS

This section includes the following diagrams:



PART	DESCRIPTION			MATERIAL
001	FINAL ASSY P391 PANEL MTD			SEE BELOW
REF	QTY	PART NO.	DESCRIPTION	
1	1	GN0460001	Assembly Wrapper 80TE	
2	1	ZN0066001	Assembly Measurement PCB	
3	2	ZN0064001	Assembly Coupling Resitor PCB	
4	1	GN0463001	Assembly Front Panel	
5	1	GN8010001	Terminal cover	
6	1	ZF8309001	Warning Label - Caution	
7	1	ZF8310001	Warning Label - Caution	
8	12	ZB4018110	Size 4 Pan Head Self Tapping Screw 6.35 Long	
9	6	ZB5366094	M4 x 6 Recessed Pan Head Screw	
10	6	ZB5002041	M4 Plain Washer	
11	1	GN9011xxx	Printed Label Set	

Figure 61 - P391 panel mounted - Final assembly drawing



PART	DESCRIPTION			MATERIAL
002	FINAL ASSY P391 RACK MTD			SEE BELOW
REF	QTY	PART NO.	DESCRIPTION	
1	1	GN0460002	Assembly Wrapper 80TE	
2	1	ZN0066001	Assembly Measurement PCB	
3	2	ZN0064001	Assembly Coupling Resitor PCB	
4	1	GN0463001	Assembly Front Panel	
5	1	ZF8309001	Warning Label - Caution	
6	1	ZF8310001	Warning Label - Caution	
7	12	ZB4018110	Size 4 Pan Head Self Tapping Screw 6.35 Long	
8	6	ZB5366094	M4 x 6 Recessed Pan Head Screw	
9	6	ZB5002041	M4 Plain Washer	
10	1	GN9011xxx	Printed Label Set	

Figure 62 - P391 rack mounted - Final assembly drawing

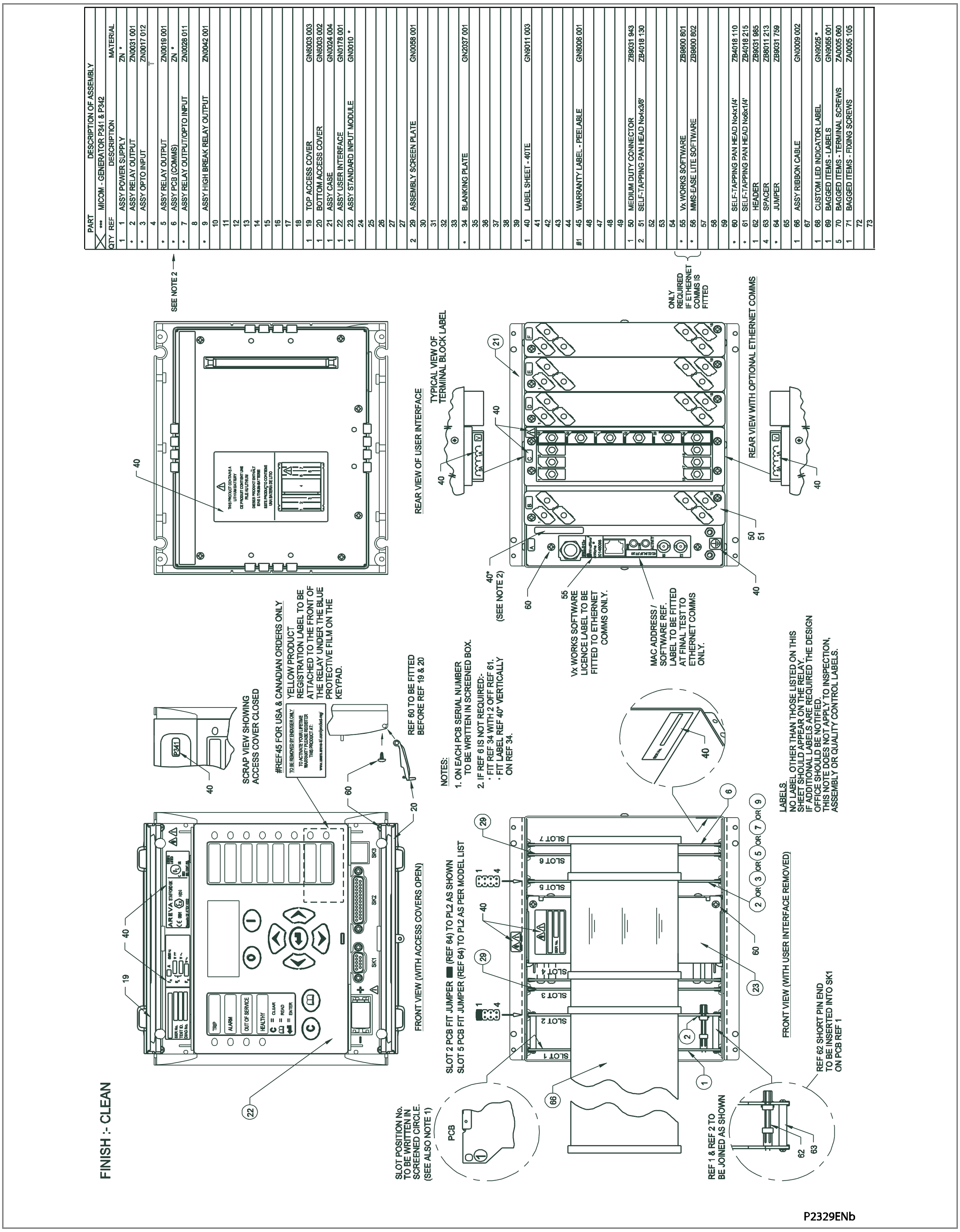


Figure 63 - Assembly P342 (40TE) 8 I/P & 7 O/P with optional I/P & O/P)

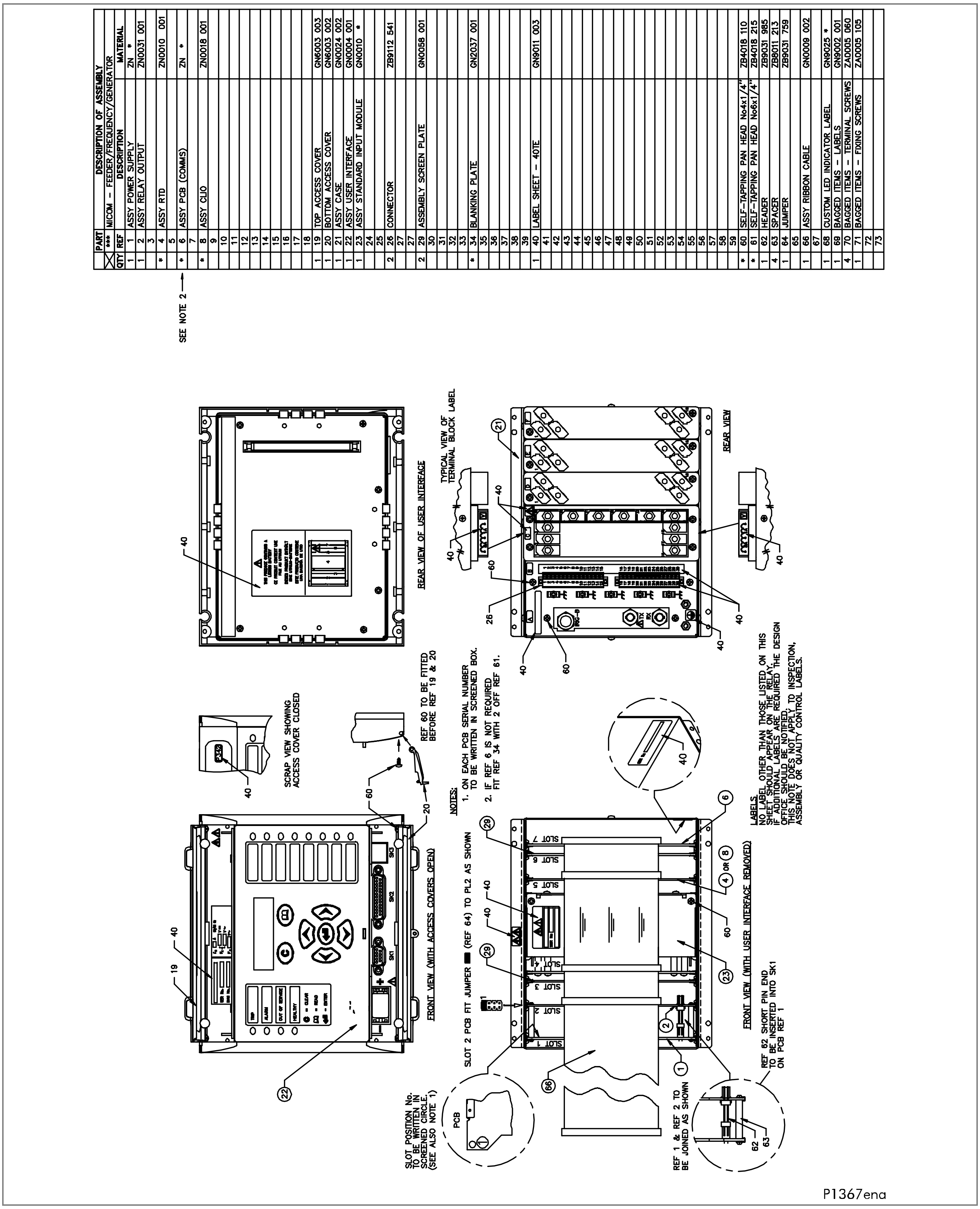


Figure 64 - Assembly P342 (40TE) (8 I/P & 7 O/P with optional RTD & CLIO)

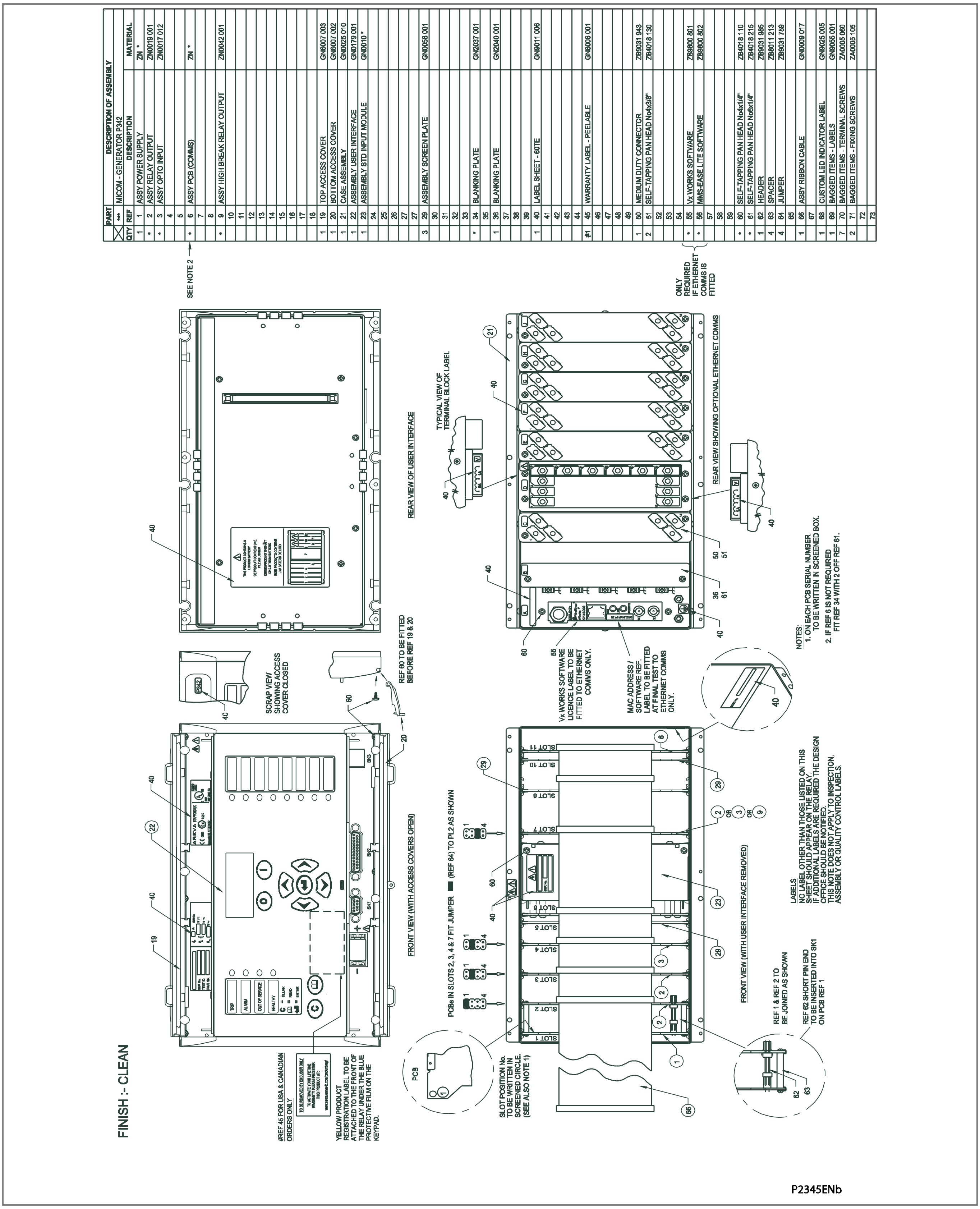


Figure 65 - Assembly P342 (60TE) (16 I/P & 16 O/P with optional I/P & O/P)

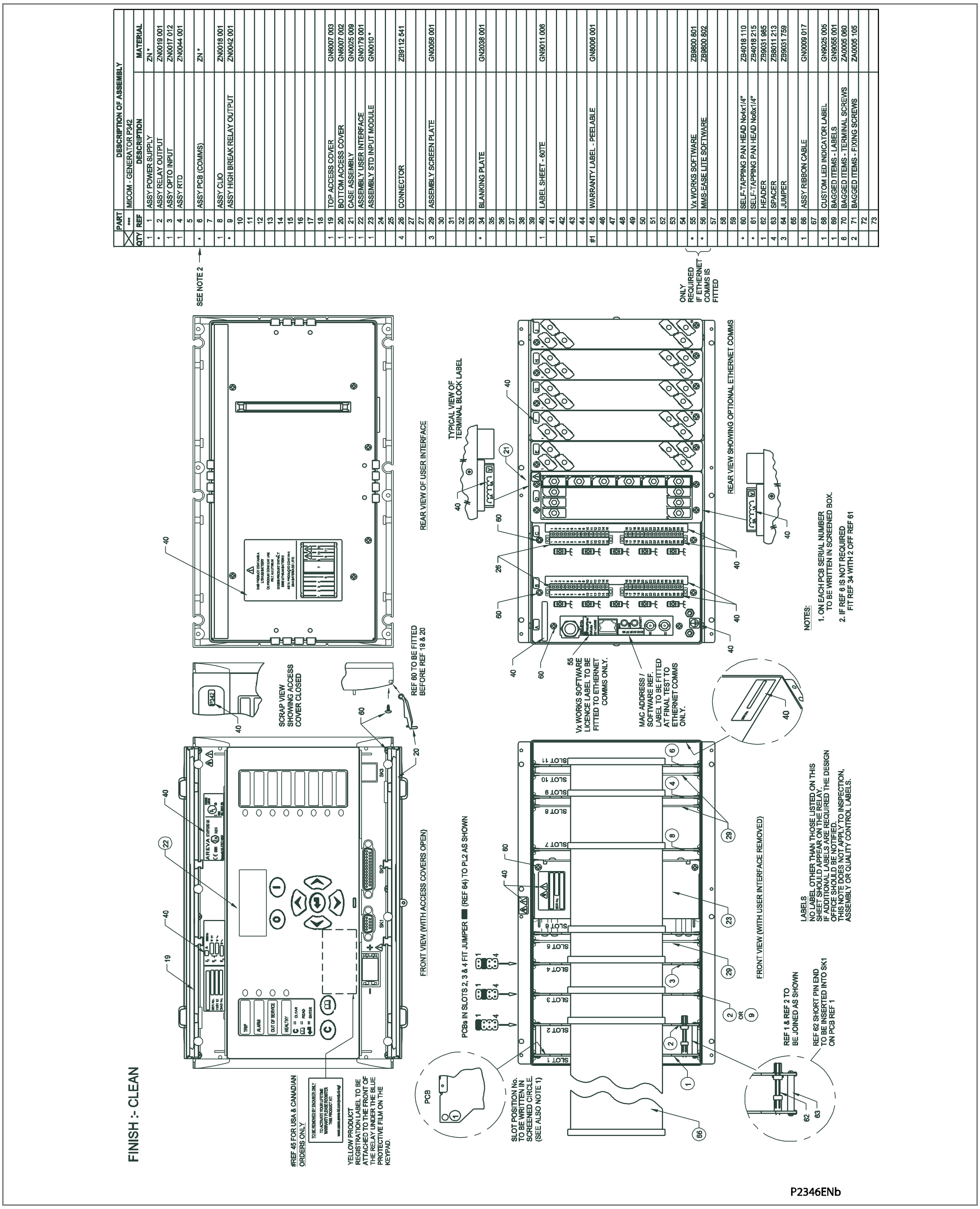


Figure 66 - Assembly P342 (60TE) (16 I/P & 8/16 O/P with optional RTD & CLIO & HB O/P)

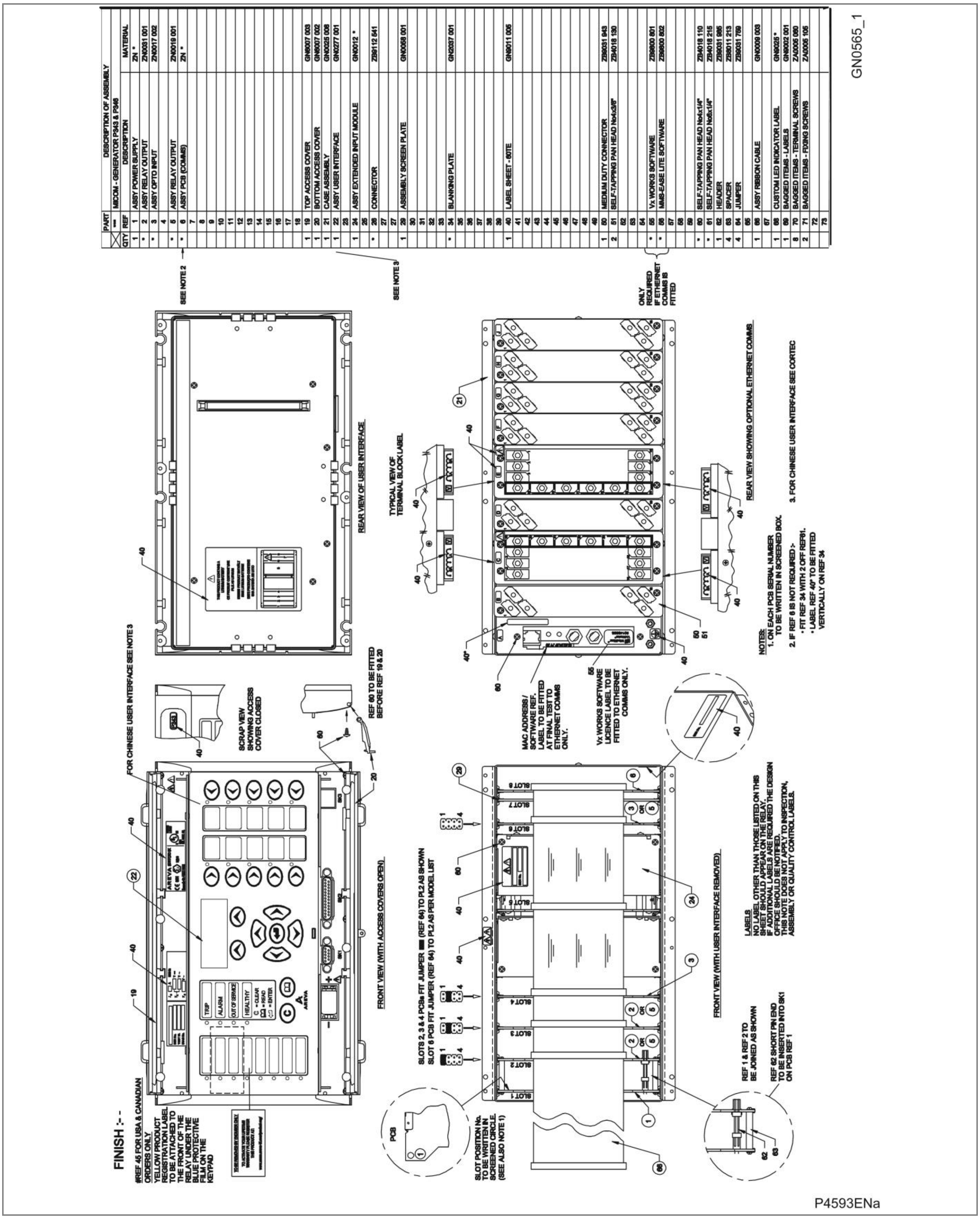


Figure 67 - Assembly P343 (60TE) (16 I/P & 14 O/P with optional I/P & O/P)

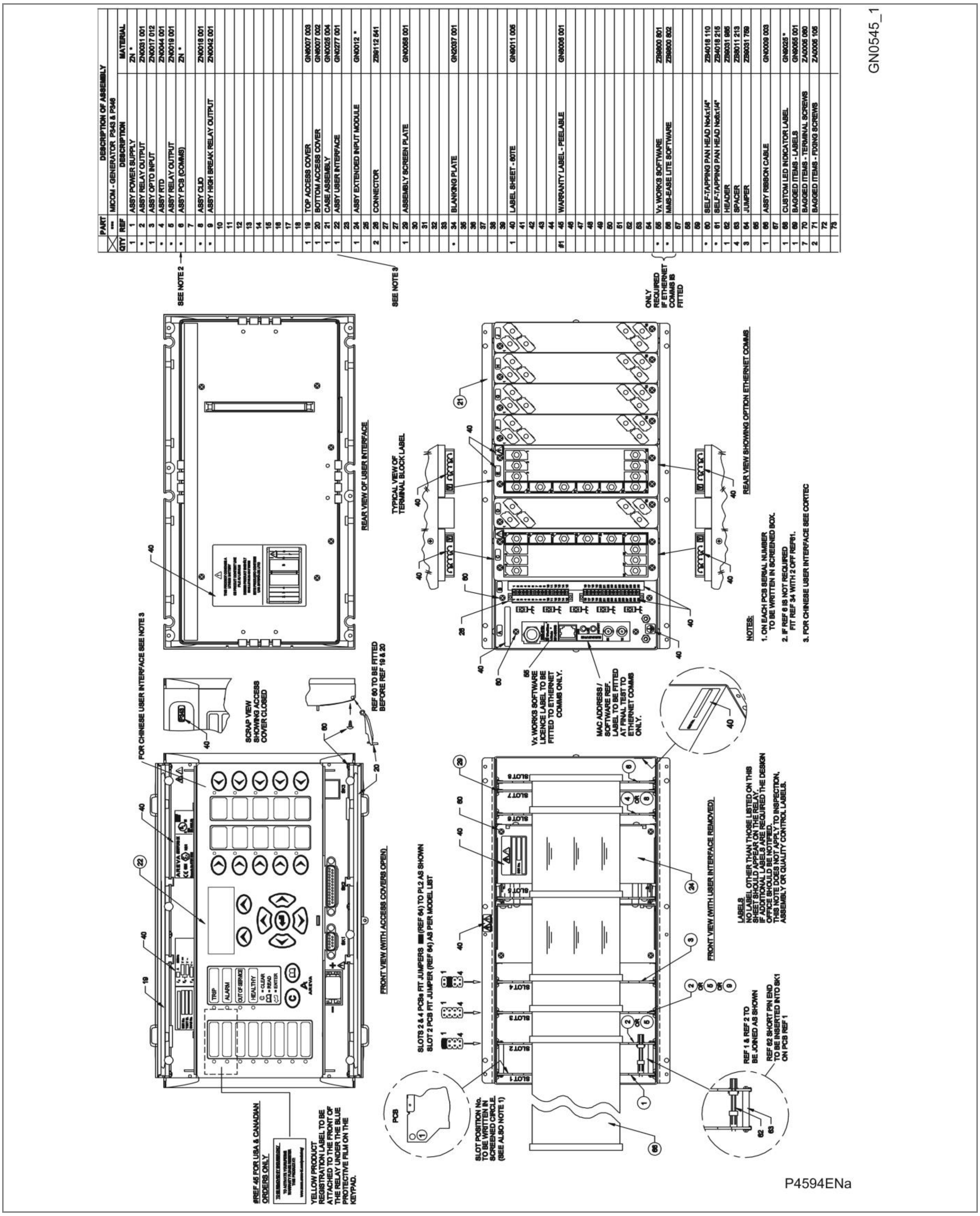


Figure 68 - Assembly P343 (60TE) (16 I/P & 7/14 O/P with optional RTD & CLIO & HB O/P)

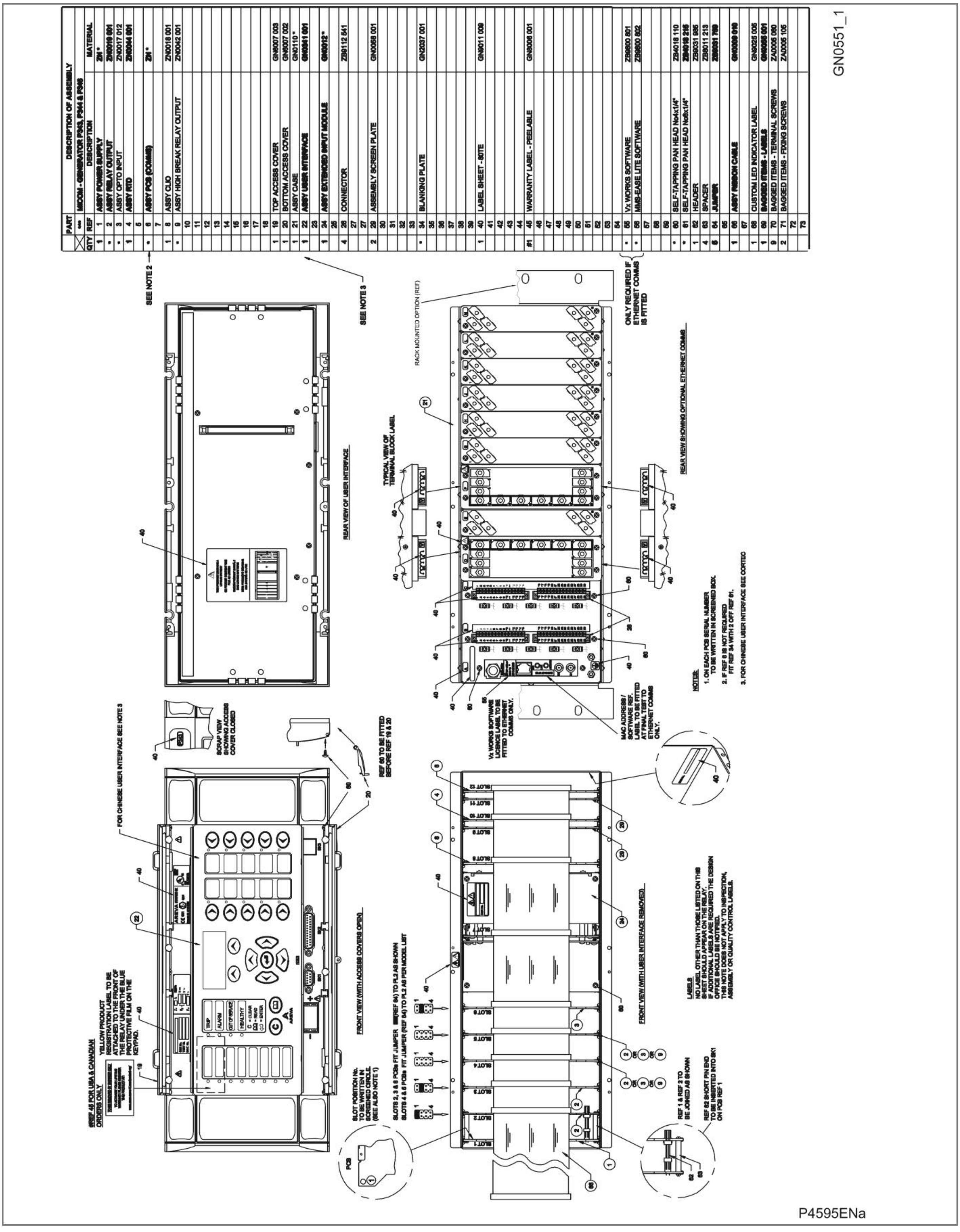


Figure 69 - Assembly P343/P344 (80TE) (16/24 I/P & 16/24 O/P with optional I/P & O/P)

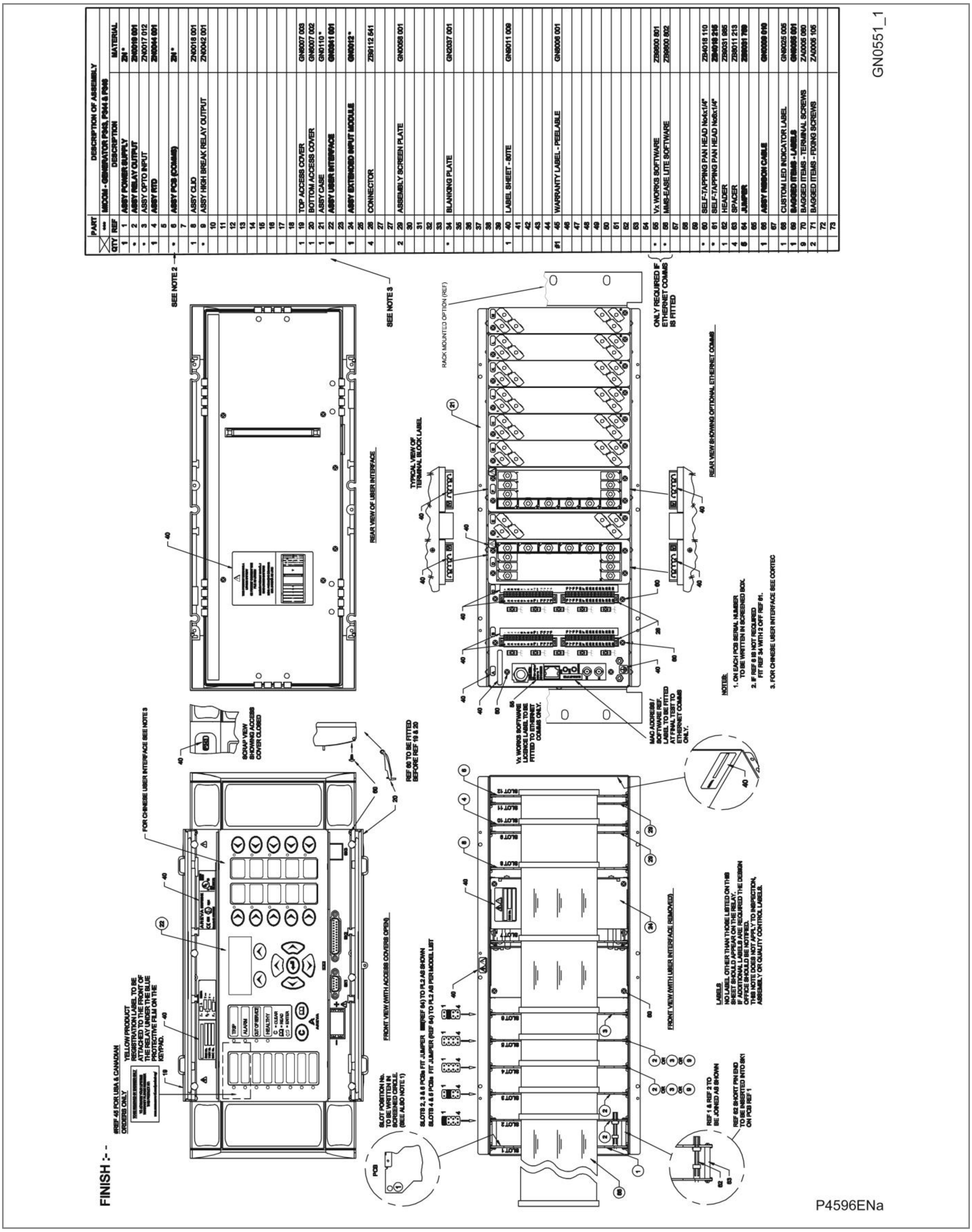


Figure 70 - Assembly P343/P344 (80TE) (16/24 I/P & 16/24 O/P with optional RTD & CLIO & HB O/P)

Notes:

CYBER SECURITY

CHAPTER 18

Date (month/year):	01/2017			
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:	P141/P142/P143 P145 P445 P44x (P442/P444) P44y (P443/P446)	L M L M M	P54x (P543/P544/P545/P546) P642 P643/P645 P746 P841A (one circuit breaker) P841B (two circuit breakers) P849	M L M M M M M
Software Version:	P14x (P141/P142/P143/P145) P445 P44x (P442/P444) P44y (P443/P446)	B2 J4/J6 E1 H4	P54x (P543/P544/P545/P546) P64x (P642/P643/P645) P746 P841A (one circuit breaker) P841B (two circuit breakers) P849	H4 B2 B3/C3 G4 H4 B1
Connection Diagrams:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P445: 10P445xx (xx = 01 to 04) P44x (P442 & P444): 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2)		P54x (P543, P544, P545 & P546): 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) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)	
	Note *This chapter covers the combinations of Products, Software Versions and Hardware Suffixes identified here. If you are using earlier software or hardware, please refer to the Schneider Electric Customer Care Centre (www.schneider-electric.com/ccc) for details of which version of this chapter to refer to.*			

CONTENTS

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FIGURES

1 OVERVIEW

1.1 Definition

Cyber security is a domain that addresses attacks on or by computer systems and through computer networks that can result in accidental or intentional disruptions. Cyber security addresses not only deliberate attacks, such as from disgruntled employees, industrial espionage, and terrorists, but also inadvertent compromises of the information infrastructure due to user errors, equipment failures, and natural disasters.

1.2 Introduction to Cyber Security

The objective of cyber security is to provide increased levels of protection for information and physical assets from theft, corruption, misuse, or accidents while maintaining access for their intended users.

To achieve this objective the owner of the grid must take into account Cyber Security at every level of his organization by the management of an ongoing process that encompasses procedures, policies, technical (software, and hardware asset) and regulatory constraints.

The following diagram outlines some of the associated topics.

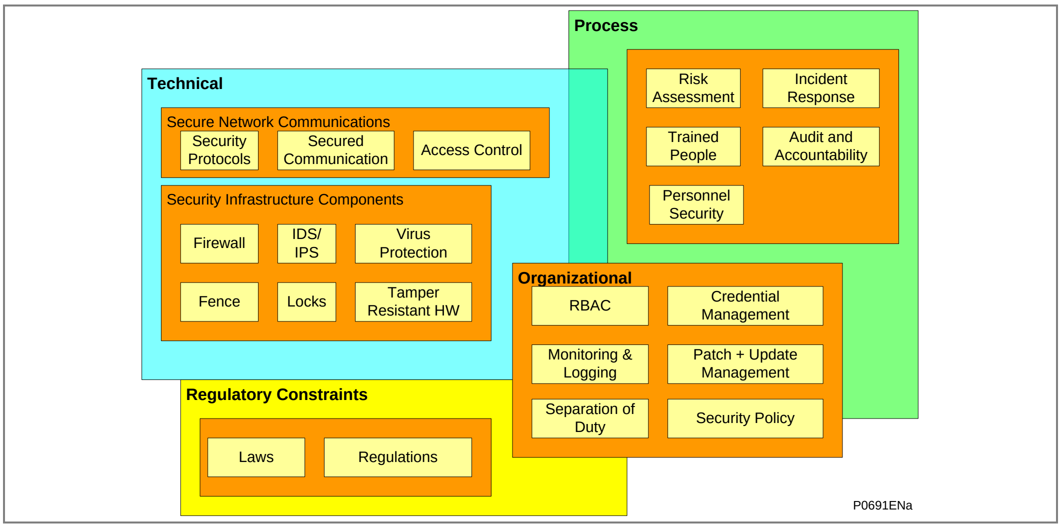

Figure 1 – Associated topics

The asset owner needs to run a continuous improvement process as outlined here:

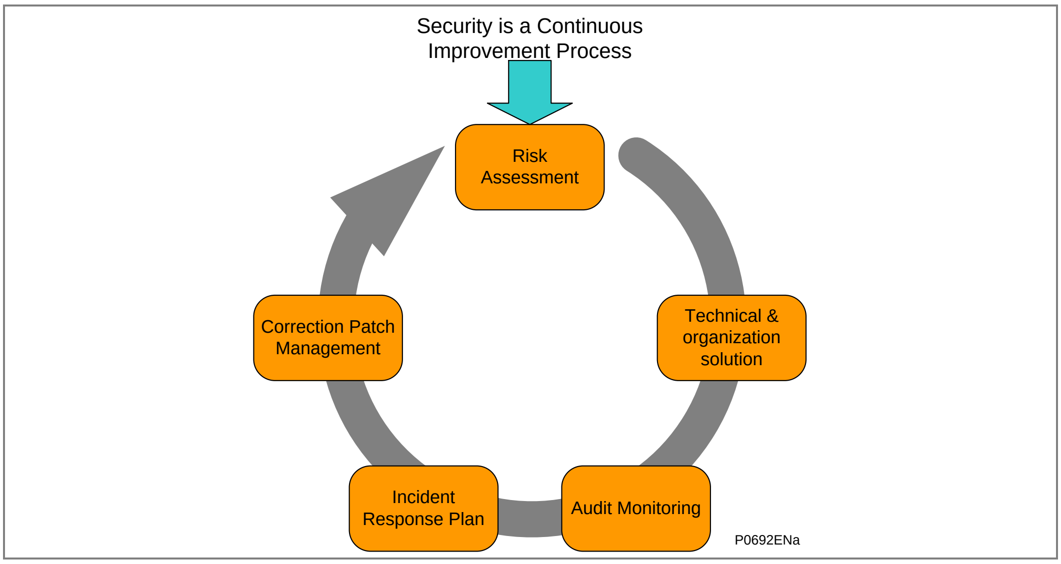

Figure 2 – Continuous improvement process

No single solution can provide adequate protection against all cyber attacks on the control network. Schneider Electric recommends employing a “defense in depth” approach using multiple security techniques to help mitigate risk.

A secured system is to offer:

- Detective controls: Monitor and record specific types of events: Security logs, Intrusion, detection systems, Video Surveillance etc.
- Preventive controls: Help blocking or controlling specific event : Antivirus, White listing, Firewall etc.
- Recovery controls: Help achieve Business continuity and Disaster recovery planning objectives in case of an incident: Backup and Restore solution.

As protective relay vendor, Schneider Electric helps the grid owner to achieve by providing technical features inside the IED, described in the next chapters.

Important	**This product contains a cyber-security function, which manages the encryption of the data exchanged through some of the communication channels. The aim is to protect the data (configuration and process data) from any corruption, malice, attack. Subsequently, this product might be subject to control from customs authorities. It might be necessary to request special authorization from these customs authorities before any export/import operation. For any technical question relating to the characteristics of this encryption please contact your Customer Care Centre - www.schneider-electric.com/ccc.**

1.3 Roles, Rights and relationship between IEC62351 and MiCOM Px4x

1.3.1 Role Based Access Control (RBAC)

The Role Based Access Control (RBAC) is a method to restrict resource access to authorized users. RBAC is an alternative to traditional Mandatory Access Control (MAC) and Discretionary Access Control (DAC).

A key feature of RBAC model is that all access is through roles. A role is essentially a collection of permissions, and all users receive permissions only through the roles to which they are assigned, or through roles they inherit through the role hierarchy.

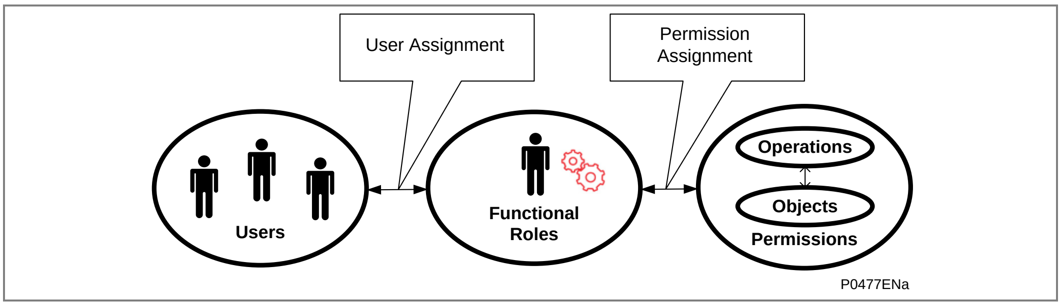

Figure 3 - RBAC Role structure

Roles are created for various job activities. The ***Permissions***, to perform certain operations, are assigned to specific roles. ***Users*** are assigned particular roles, and through those role assignments acquire the computer permissions to perform particular computer-system functions. Since ***users*** are not assigned permissions directly, but only acquire them through their role (or roles), management of individual user rights becomes a matter of simply assigning appropriate roles to the user's account; this simplifies common operations, such as adding a user, or changing user's account.

RBAC defines four different concepts:

RBAC Standard Definition	Description
Object	An ***object*** can represent information containers (e.g. files, directories in an operating system, tables and views in a database management system) or device resources, such as IEDs.
Subject	A ***subject*** is a user of the system. Note that a subject can be a person, or an automated agent / device.
Right	A ***right*** is the ability to access an object in order to perform certain operations (e.g. setting a data or reading a file)
Role	A ***role*** defines a certain authority level in the system. Rights are assigned to roles.

Table 1 – RBAC object, subject, rights and roles definitions

RBAC defines three primary rules:

RBAC Rule	Description
Role assignment	A subject can exercise a permission only if the subject has selected or been assigned a role.
Role authorization	A subject's active role must be authorized for the subject. With rule 1 above, this rule ensures that users can take on only roles for which they are authorized.
Permission authorization	A subject can exercise permission only if the permission is authorized for the subject's active role. With rules 1 and 2, this rule ensures that users can exercise only permissions for which they are authorized.

Table 2 – RBAC permission and authorization rules

1.3.2 User Roles

Different named roles are associated with different access rights. Roles and Rights are setup in a pre-defined arrangement, according to the IEC62351 standard, but customized to the MiCOM Px4x equipment.

When the user tries to access an IED, they need to login using their own username and their own password. The username/password combination is then checked against the records stored on the IED. If they are allowed to login, a message appears which shows them what Role they have been assigned to. It is the role that defines their access to the relevant parts of the system.

The default user roles for MiCOM Px4x are shown here:

Role	Description
VIEWER	Can View what objects are present within a Logical-Device by presenting the type ID of those objects.
OPERATOR	An Operator can view what objects and values are present within a Logical-Device by presenting the type ID of those objects as well as perform control actions.
ENGINEER	An Engineer can view what objects and values are present within a Logical-Device by presenting the type ID of those objects. Moreover, an engineer has full access to Datasets and Files and can configure the server locally or remotely.
SECADM	Security Administrator can change subject-to-role assignments (outside the device) and role-to-right assignment (inside the device) and security policy setting; change security setting such as certificates for subject authentication and access token verification.
SECAUD	Security Auditor can view audit logs

Table 3 – Default user roles summary for MiCOM Px4x

Each authorized user must be placed into at least ONE of these roles that most suits their job description. It is possible to assign a user into a different role; and/or to change the rights associated with a particular role. This means that the administrator can change the access rights for one role; and this will affect ALL the users who are assigned to that role.

It is possible for MiCOM Px4x to create the customized user roles.

1.3.3 Rights

In a similar way in which a set of pre-defined Roles have been created, a pre-defined set of Rights have been created.

These Rights give different permissions to look at what devices may be present, what those devices may contain, manage data within those devices (directly or by using files) and configure rights for other people.

A list of the pre-defined Rights for IEC 62351-8 is given here:

Right	Description
VIEW	Allows the subject/role to discover what objects are present within a Logical-Device by presenting the type ID of those objects. If this right is not granted to a subject/role, the Logical-Device for which the View right has not been granted shall not appear
READ	Allows the subject/role to obtain all or some of the values in addition to the type and ID of objects that are present within a Logical-Device;
DATASET	Allows the subject/role to have full management rights for both permanent and non-permanent Datasets;
REPORTING	Allows a subject/role to use buffered reporting as well as un-buffered reporting;
FILEREAD	Allows the subject/role to have read rights for file objects;
FILEWRITE	Allows the subject/role to have write rights for file objects. This right includes the FILEREAD right
CONTROL	Allows a subject to perform control operations;
CONFIG	Allows a subject to locally or remotely configure certain aspects of the server;
SETTINGGROUP	Allows a subject to remotely configure Settings Groups;
FILEMNGT	Allows the role to transfer files to the Logical-Device, as well as delete existing files on the Logical-Device;
SECURITY	Allows a subject/role to perform security functions at both a Server/Service Access Point and Logical-Device basis. To add Information about the concept of Rights.

Table 4 – Pre-defined rights for IEC 62351-8

The specific Rights for MiCOM Px4x are listed below. These are dependent on the IED data type. Please refer to each product MD file (Menu Database) for the IED data type.

Rights	Authorized Actions to IED	IED_DESC	IED_DATA	DISPLAY	IED_CONFIG	PROT_CONFIG	IEC_COMMAND	AUDIT	IED_FN_KEY	IED_CLEAR
Read Only (SAT default_access_right)	Read	x	x	x	x		x			
	Write	x								
IED Configuration (SAT configuration_right)	Read/write/upload/do wnload				x					
HMI Display Settings (SAT display_action_right)	Read/write/select			x						
Protection Configuration (SAT protection_configuration_right)	Read/write					x				
IED Commands (SAT control_right)	Read/write/clear/reset /select						x			
Reading of Records & Events (SAT audit_read_right)	Read/select/upload							x		
Extraction of Records and Events (SAT audit_write_right)	Send/accept							x		
IED Function Key (SAT fn_key_access_right)	Write								x	
IED Records Clear (SAT clear_right)	Read/write/clear									x

Table 5 – Specific rights for MiCOM Px4x

1.3.4 Roles and their Access Rights

A complete list of the Roles and their access Rights is shown in this table:

Rights \ Roles		VIEWER	OPERATOR	ENGINEER	SECADM	SECAUD
Pre-defined Rights for IEC 62351	VIEW	X	X	X	X	X
	READ		X	X	X	X
	DATASET			X		
	REPORTING	X	X	X		X
	FILEREAD					X
	FILEWRITE			X	X	
	FILEMNGT			X	X	
	CONTROL		X		X	
	CONFIG			X	X	
	SETTINGGROUP				X	
	LOGS				X	X
	SECURITY				X	
Specific Rights for MiCOM Px4x	Read Only	X	X	X		X
	IED Configuration			X		
	HMI Display Settings		X	X		
	Protection Configuration			X		
	IED Commands		X	X		
	Reading of Records and Events	X	X	X		X
	Extraction of Records and Events		X	X		X
	IED Function Key		X	X		
	IED Clear			X		

Table 6 – Pre-defined roles (and rights) for IEC 62351-8 and MiCOM Px4x

Important **The reason why these are described as Default, is that it is possible to change the definitions of Roles and Rights, using the full version of the SAT software. Depending on the work done by the system administrator, it is possible that your own situation may vary from these initial recommendations.**

1.4 Security Administration Tool (SAT) Software

Important **This can only be used with Px4x relays with cyber security CSL1 features.**

Important **For Dual Ethernet cards the SAT functionality is available from communication interface 1. The connection to the SAT would be available from interface 2 only when interface 1 is disconnected from the network.**

The Security Administration Tool (SAT) is the security configuration tool of MiCOM Px4x equipment. It allows the security administrator to define the security policy to the IEDs.

The Security Administrator manages RBAC and security policies data. Security Administrator defines needs to protect devices in accordance with user privileges. Thus, the system security can be configured easily and precisely.

The SAT is used by the Security Administrator to manage the system's security database and deploys security configurations to IED(s).

The SAT allows to Manage User Accounts, Roles, Permission, Elements to Secure (ETS) and Security Server parameters without connection with devices. Information is store on the MS SQL database. This is the Offline mode. SAT allows devices management connected on network. This is the online mode.

The Role Based Access Control (RBAC) is a method to restrict resource access to authorized users. Please refer to this documentation on section "*System RBAC Management*" for more details.

The following table contains the main user main functions of the SAT:

Category	User Function	Note
Offline General Administration	User Accounts Management	User Account Functions: * Creation * Edition * Suppress * Viewing * Sorting * Filtering
	Server Configuration	
	Users Accounts & Roles association Management	Associate a role to the user account
Offline Advanced Administration	Roles Management	Roles Functions: * Creation * Edition * Suppress * Viewing * Sorting
	Element To Secure (ETS) Management	Define ETS which are in fact the PACiS assets present in the project (C264, PACiS Gateway, ECOSUI, IED and SAM). Add, Suppress and Sort permissions associated with the ETS.
	Global Security Management	The Global Security allows scope(s) and associate or disassociate role(s) management for each user account. The security administrator manages the current scope by the Roles: * View Roles List, User Account List and associations User-Roles or Role-Users * Associate / dissociate role(s) for each User Account * Add / Suppress User account(s) for each Role
	Permission access	Define parameters: * Password validity * Inactivity period * Automatic logout period * Maximum attempts of login and lockout period
Communication	Refresh IED list	
	Display IED Logs	
	Display SAM Logs	
	Push RBAC and Security Policies	Send Security Configuration to all Devices integrating Security features.

Table 7 – Main SAT user functions

The details of how to use the SAT are provided in the SAT documentation:

SAT (Security Administration Tool) Documentation - User Guide

This is available from the Schneider Electric website: www.schneider-electric.com.

2 MICOM PX4X CYBER SECURITY IMPLEMENTATION

Schneider Electric MiCOM Px4x IEDs have always been and will continue to be equipped with state-of-the-art security measures. Due to the ever-evolving communication technology and new threats to security, this requirement is not static. Hardware and software security measures are continuously being developed and implemented to mitigate the associated threats and risks.

Considered some users may not want to use the cyber security, Schneider Electric offers MiCOM Px4x relays with CSL0 and CSL1 as below:

CSL0: Simple password management, No SAT required.

CSL1: Advanced cyber security, SAT required.

This depends on the model number, as CSL1 is depend on the Ethernet communication. Hence if the IED if supports only legacy protocol this will be CLS0 default as. The digit position number 9 (protocol options) in the Cortec / model number is used to distinguish it.

Protocol Option Number	Protocol options	Cyber Security options
1	K-Bus/Courier	CSL0
2	Modbus	CSL0
3	IEC 60870 -5 - 103	CSL0
4	DNP3.0	CSL0
6	IEC 61850 Edition 1 / 2 and Courier via rear K-Bus/RS485	CSL0
7	IEC 61850 Edition 1 / 2 and CS103 via rear port RS485	CSL0
B	IEC 61850 Edition 1 / 2 and DNP3oE and DNP Serial	CSL0
G	IEC 61850 Edition 1 / 2 and Courier via rear K-Bus/RS485	CSL1
H	IEC 61850 Edition 1 / 2 and CS103 via rear port RS485	CSL1
L	IEC 61850 Edition 1 / 2 and DNP3oE and DNP3 serial	CSL1

Table 8 – MiCOM Px4x protocol options for cyber security options

2.1 MiCOM Px4x with CSL1 - Advanced Cyber Security

For MiCOM Px4x IEDs which support CSL1, this means the IED supports advanced user account right management. Moreover, the IED supports security logs/events and secure administration capability.
If you want to use cyber security, you need to order the IED that supports CSL1. In this case, the Security Administration Tool (SAT) is required for RBAC configuration.
At the IED level, these cyber security features have been implemented:

- Passwords management (via the SAT)
- RBAC Management (via the SAT)
- User Locking
- Inactivity Timer
- RBAC recovery
- Port Disablement (via S1 Studio or the front panel)
- Simple Network Management Protocol (SNMP)
- Security Logs

2.1.1 Password Management (via the SAT)

For the IED if CSL1 supported, there are two types of password possible for the IED access: alphanumeric password or Arrow Key password.

The alphanumeric password is only settable via the SAT:

- Passwords may be any length between 1 and 32 characters long
- Passwords may contain any ASCII character in the range ASCII code 33 (21 Hex) to ASCII code 122 (7A Hex) inclusive
- Passwords may or may not be NERC/IEEE 1686 compliant
- The alphanumeric password will used for courier client access

For more details about NERC/IEEE 1686 password compliant, please check the standard.

The Arrow Key password is only settable via the SAT:

- The Arrow Key password is a combination of the four arrow keys on the front panel
- The Arrow Key password may be any length between 1 and 8 of arrow keys long
- The Arrow Key password can only used in the front panel
- The user also can disable the Arrow Key password by not setting it

Important	**If the Arrow Key password is not configured, the alphanumeric password will be used for the front panel access. In this case, alphanumeric passwords longer than 16 characters are not allowed.** **MiCOM S1 Studio and the front panel are not allowed to change the password.**

2.1.2 RBAC Management (via the SAT)

By default, the IED includes a factory RBAC which has three users, and for each user, the Rights depend on the user Role. Please refer to the *Roles and their Access Rights* section for more details.

Username	Role	Default password
SecurityAdmin	SECADM	AAAAAAAA
EngineerLevel	ENGINEER	AAAA
OperatorLevel	OPERATOR	AAAA

Table 9 – Factory RBAC

A Local Default Access function also available for the default RBAC, with the VIEWER role, which allows everyone login the IED in the front panel with VIEWER role. For more details about the Local Default Access function, please refer to the *Local Default Access* section.

For more information about how the SAT management the RBAC and cyber security policies, please see the *Security Administration Tool (SAT)* section.

2.1.3 User Locking

The user is locked out temporarily, after a defined number of failed password entry attempts.

Important	**If a user is locked out, the block is applied to that named user and to the all IED interfaces. The blocking of one user, does not apply blocks to others. If the user entry is blocked, recover the RBAC or push a new RBAC will not reset the blocked user entry, but IED reboot will reset the blocking time and attempts count, so the user entry will be unblocked.**

An invalid password entry will display a 'Login Failed PW Incorrect' message for 2s. It also reduces the Attempts Remaining Counter (Attempts Remain) by 1 and it remains at this level until the interface inactivity timer expires (CSL0 models) or until the Password Attempts Timer configured in SAT expires (CSL1 models) or another password entry is made. If Attempts Remain equals 1 then a '1 Attempt Left' warning will also be issued for 2s. When Attempts Remain equals 0 then a 'USER LOCKED OUT' warning is displayed for 2s and access for that user is blocked. If the Blocking Timer expires, or the correct password is entered before Attempts Remain reaches zero, then the Attempts Remain is reset to the Attempts Limit.

Once the user entry is blocked, the Blocking Timer is initiated. If the locked out user is selected whilst the Attempts Remain is zero a 'USER LOCKED OUT' error message is displayed.

2.1.4 Inactivity Timer

The MiCOM device runs an inactivity timer, which means that it records the last time an action was taken by a user who was logged in.

If the user does not perform an action within a pre-defined interval, the user will be logged off. This is to reduce the risk that a device can accidentally be left open to access by unauthorized people.

The inactivity timer is separate for each interface.

The inactivity timer is configurable by using the SAT.

Important	**In case of a connection through an Ethernet interface, the actual inactive time depends on the setting value of both "Minimum inactivity period" & "[0E A7] ETH Tunl Timeout", the smaller value of both timers will be applied.**

Refer to the Table 12 for more details about the settings.

2.1.5 RBAC Recovery

RBAC recovery is the means by which the device can be reset to the factory RBAC settings if required. To obtain the recovery password, the customer must go to www.schneider-electric.com/ccc to raise a recovery password request and supply the IED *Security Code*.

Caution	**The "recovery" password gives you access to the Factory RBAC Configuration. This action deletes all existing users (and their passwords), and restores to Factory RBAC Configuration. Recover the RBAC does not affect relay proper settings and does not provoke reboot of the relay - the protection functions of the relay are always maintained.**

2.1.5.1 Generate Security Code

The security code is a 16-character ASCII string. It is a read-only parameter. The IED generates its own random security code. This is when a new code is generated:

- On power up
- On expiry of validity timer (see below)
- When the recovery password is entered

As soon as the security code is ***first*** displayed on the LCD display, a validity timer is started. This validity timer is set to 120 hours and is not configurable. The validity timer is not reset if you request a subsequent code within the 120 hour period.

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

```
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.

Important	**The recover password will be invalid once the new Security Code is generated, so please make sure the IED is always powered on before you get the reover password, and make sure you input the recover password within 120 hours.**

2.1.5.2 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 is done at the local front panel and it causes the IED to reset the RBAC back to default.

On this action, the following message is displayed on the front panel of the IED:

```
RBAC reset done
Press any key
```

2.1.6 Port Disabling (Equipment Hardening)

The availability of unused ports could provide a security risk. Hence, unused ports can be disabled (also known as equipment hardening) – either via the front panel or by MiCOM S1 Studio. An Engineer role is needed to perform this action.

These physical ports and logical ports can be enabled/disabled:

Port types	Menu text	Col	Row	Default Setting	Available Value
Physical Ports	Front port	25	05	Enable	Enable/Disable
	Rear Port 1	25	06	Enable	Enable/Disable
	Rear Port 2	25	07	Enable	Enable/Disable
	Ethernet Port 1	25	08	Enable	Enable/Disable
	Ethernet Port 1/2	25	09	Enable	Enable/Disable
	Ethernet Port 2/3	25	0A	Enable	Enable/Disable
	Ethernet Port 3	25	0B	Enable	Enable/Disable
Logical Ports	Courier Tunnel	25	0C	Enable	Enable/Disable
	IEC61850	25	0D	Enable	Enable/Disable
	DNP3oE	25	0E	Enable	Enable/Disable

Table 10 - Port hardening settings

Note	*The port disabling setting cells are not provided in the settings file. In addition, it is not possible to disable simultaneously more than one physical port or Logical port.* *New redundant Ethernet boards have three physical ports but total two interfaces. The actual disabled physical port is depended on the redundant communication mode (PRP, HSR or Dual IP). Refer to the Dual Redundant Ethernet Board (Upgrade) (DREB) chapter (Px4x/EN EB) for more details.*

When the Ethernet board related physical ports or logical ports are disabled or enabled, the Ethernet card will reboot. The status of the ports will be available after reboot of the Ethernet board.

For more details about how to disable/enable the unused ports, please see sections:

- How to Disable a Physical Port
- How to Disable a Logical Port

2.1.7 Simple Network Management Protocol (SNMP)

Simple Network Management Protocol (SNMP) allows security monitoring of events and alarms. Standard third-party SNMP client software can be used to access the log of these events and alarms. Access to the SNMP MIB is given on a read-only basis. For further details of gaining access to the MIB, please contact Schneider Electric.

2.1.8 Security Logs

The Security Logs needs to store logs from each item of equipment. These logs are generated by the system, and cannot be edited by the user. A variety of different items are recorded, including: bad/faulty access attempts, login attempts, authentication errors, changes to roles, users and access control lists, network backup and configuration changes, communication failures and so on.

Security logs emissions depend on the security standards that are configurable by the SAT.

The security logs will push to a Syslog server if the Syslog server IP address and Syslog server IP port are configured and connected.

SAT also can be used to explore the security logs but MiCOM S1 studio is not supported.

The settings for the security log standards and Syslog server IP address and ports are listed in the *Configurable cyber security settings* table. For more detail about the security log configuration, please refer to the SAT documentation.

Note	*The Security logs time stamp may be time shifted by several milliseconds compared with local event log.* *The security logs will not be generated if the Ethernet card is starting up.* *If the Syslog server is unavailable, the new logs will be stored and overwriting the oldest logs.*

This table lists the security logs categories available for each standard.

Log ID	Additional field	Explanation	Level	Standards					
				BDEW	E3	NERC CIP	IEEE 1686	IEC 62351	CS Phase 1
CONNECTION_SUCCESS	The additional field will contain the issuer of the connection: LOCAL or NETWORK	Successful connection	INFO	x	x	x	x		x
CONNECTION_FAILURE		Failed connection (wrong credentials)	WARNING	x	x	x	x		x
CONNECTION_FAILURE_ AND_BLOCK		Failed connection (wrong credentials) triggering the blocking of the account on the IED	DANGER	x	x	x	x		x
CONNECTION_FAILURE_ ALREADY_BLOCKED		Failed connection because of a blocked userID on this IED	DANGER	x	x	x	x		x
DISCONNECTION		Disconnection triggered by the peer /user	INFO	x	x	x	x		x
DISCONNECTION_TIMEOUT		Disconnection triggered by a timeout	INFO	x	x	x	x		x
CONTROL_OPERATION	Type & Data associated to the control	Trace and control / override of real data from a peer	INFO				x		
CONFIGURATION_ DOWNLOAD	Version	Download of the configuration file from the device - Files include PSL, Courier setting, DNP setting, MCL/CID and user curves (crv)	INFO				x		
CONFIGURATION_UPLOAD	Version	Upload of a new configuration file into the device - Files include PSL, Courier setting, DNP setting, MCL and user curves (crv)	INFO				x		
RBAC_UPDATE	Version	Update of the RBAC cache in the IED	INFO				x		x
SEC_LOGS_RETRIEVAL	Version	Retrieval of the security logs of the IED	INFO				x		
TIME_CHANGE	New & Old time	Modification of the time of the IED	INFO				x		
REBOOT_ORDER	None	Reboot order sent to the IED / IED start up	DANGER				x		x
PORT_MANAGEMENT	Port, action (enable / disable)	Any comms port enabled / disabled	INFO						x
AUTHORIZATION_REQ	Action, object	Any authorization request sent to the CS brick	INFO			x		x	x

Table 11 – Security logs recorded

2.1.9 Common Cyber Security Settings

The System Administrator can customize the cyber security settings at the SAT. The following table shows the common cyber security settings. Parts of settings also are visible on the IED with specific Courier cells but not editable in IED or MiCOM S1 Studio. These are shown in the right hand columns of this table:

Setting in SAT	Default Setting	Available Value	Menu in IED	Col	Row
Minimum inactivity period	15	1 to 99 Minutes	-	-	-
If the user does not perform any action within this interval, the user will be logged off.					
Allow user locking	Yes	Yes/No	-	-	-
Option allows user account locking					
Maximum login attempts	5	1 to 99	Attempts Limit	25	02
The maximum failed password entry attempts, the user will lock once the attempts reached.					
Password attempts timer	3	1 to 30 Minutes	Attempts timer	25	03
The time for reset the attempts count to 0. The user got to maximum login attempts.					
Automatic user account unlocking	Yes	Yes/No	-	-	-
Enable/disable the attempts times aromatic reset function.					
Locking period duration	240	1 to 86400 Seconds	Blocking timer	25	04
The Locking period duration (seconds)					
Password Complexity	None	None / IEEE1686/ NERC	-	-	-
Set the password compliant standard.					
Log and monitoring standard	BDEW	BDEW / E3 /NERC-CIP / IEE1686 / IEC62351/ CS_PH1	-	-	-
Setup security log emission standard					
Syslog server IP address	0.0.0.0		-	-	-
Syslog server IP address					
Syslog server IP port	601	1 to 65535	-	-	-
Syslog server IP port					
SNMP client IP address	0.0.0.0		-	-	-
SNMP client IP address					

Table 12 – Configurable cyber security settings

These settings show some common information about cyber security, which are not configurable whether by SAT, or MiCOM S1 Studio or the front panel.

Menu in IED	Col	Row	Description
User Banner	25	01	Show user banner information: ACCESS ONLY FOR AUTHORITY USERS
Attempts remain	25	11	Show the remains attempt times for user login.
Blk time remain	25	12	Show the remains time for blocked user to unlock
User Name	25	21~2F	Configured user name (in SAT)
Security Code	25	FE	The security code used to recovery the password.
RBAC Password	25	FF	Enter 16 characters recover password to recovery password

Table 13 – Un-configurable cyber security settings

2.1.10 Local Default Access

Local Default Access function can be disabled/enabled in the SAT.
The intention for Local Default Access function is to allow the user easy to access the IED from the front panel and without any authorization required. This means if the Local Default Access function is enabled, everyone will be authorized to access the front panel with associated Rights.

By default, the Local Default Access has the VIEWER role, it is also possible to associate the other Roles to the Local Default Access, which is configurable in the SAT.
Local Default Access function is only available in the front panel.
The Local Default Access login/logout process is invisible for the user.

2.2 MiCOM Px4x with CSL0- Simple Password Management

For MiCOM Px4x IED with CSL0, as the Security Administration Tool (SAT) is not supported, all the cyber security features which need SAT support will not be available.

This section describes the different implementations by comparing with CLS1.

The cyber security features that are not mentioned in this section will default to be the same as CSL1.

2.2.1 Password Management

For MiCOM Px4x IED with CSL0, SAT is not supported for the configuration, so only the alphanumeric password can be used.

- The alphanumeric password is settable via MiCOM S1 Studio and the Front panel
- Passwords may be any length between 1 and 16 characters long
- Passwords may contain any ASCII character in the range ASCII code 33 (21 Hex) to ASCII code 122 (7A Hex) inclusive
- No password compliance is required
- The alphanumeric password will used for Courier access and the front panel access

Arrow key password is not available for IED with CLS0.

2.2.2 Fixed Factory RBAC

For MiCOM Px4x IED with CSL0, the user list and its role/right will be fixed as factory RBAC and not configurable. Refer to the *Factory RBAC* table for more details.

2.2.3 Security Logs/SNMP Services

The security logs/SNMP services are not available for MiCOM Px4x IED with CSL0.

2.2.4 Cyber Security Settings

For MiCOM Px4x IED with CSL0, all cyber security settings are fixed as default setting and un-configurable. Refer to the *Configurable cyber security settings* table for the default settings.

2.2.5 Disable/Blank Password

For MiCOM Px4x IED with CSL0, it is possible to remove the user password. In MiCOM S1 Studio, this is achieved by click the BOX “Disable the password”. In the IED, this is achieved by setting the password as blank.

Once the password is disabled/blank, the user can login to the IED directly and there is no need to enter the password.

3 HOW TO USE CYBER SECURITY FEATURES

These sections shows the most common tasks associated with Cyber Security features. For many of these tasks, the steps you take are the same as you have performed previously; with the main changes being in the steps you use to login and/or logout.

3.1 How to Login

3.1.1 Local Default Access

If the Local Default Access is enabled, the user may login to the front panel with associated roles.

See Table 14 for the applied cases.

3.1.2 Auto Login

Auto login means the user will login the IED automatically and no need to select the user name and enter the password. In this case, the user will be authorized with relevant rights. The auto login will be applied in these cases:

CS Version	Interface	RBAC/PW Cases	Login Process
CSL1	Front panel	Factory RBAC	Auto login with **EngineerLevel**
		Customized RBAC	Local Default Access Enabled: Login with **Local Default Access** Local Default Access Disabled: Login with **Prompt User List**
	Courier Interface	All cases	Login with **Prompt User List**
CSL0	Front panel	Factory RBAC	Auto login with **EngineerLevel**
		Password changed	**EngineerLevel** password is "AAAA" or is disabled/blank: Auto login with **EngineerLevel** **OperatorLevel** password is "AAAA" or is disabled/blank: Auto login with **OperatorLevel** **EngineerLevel** and **OperatorLevel** password changed: Auto login with **ViewerLevel Access**
	Courier Interface	Factory RBAC	Auto login with **EngineerLevel**
		Password changed	**EngineerLevel** password is "AAAA" or is disabled/blank: Auto login with **EngineerLevel** **OperatorLevel** password is "AAAA" or is disabled/blank: Auto login with **OperatorLevel** **EngineerLevel** and **OperatorLevel** password changed: Login with **Prompt User List**

Table 14 – Auto Login process

For more details about the Factory RBAC, please refer to Table 9.

3.1.3 Login with Prompt User List

This login process will happen if:

- The Auto login process is not applied.
- Or high authorization is required for the current operation.

In this case, the IED will prompt the user list, and the user needs to select proper user name and enter the password to login.

3.2 How to Logout

3.2.1 How to Logout at the IED

For security consideration, it would be better to “logout' the IED once the configuration done. You can do this by going up to the default display. When you are at the default display and you press the ‘Cancel’ button, you may be prompted to log out with the following display:

```
ENTER TO LOGOUT
CLEAR TO CANCEL
```

You will be asked this question if you are logged in.

If you confirm, the following message is displayed for 2 seconds:

```
LOGGED OUT
User Name
```

If you decide not to log out (i.e. you cancel), the following message is displayed for 2 seconds.

```
LOGOUT CANCELLED
User Name
```

Note	*The MiCOM IED runs a timer, which logs the user out after a period of inactivity. For more details, refer to the Inactivity Timer section.*

3.2.2 How to Logout at MiCOM S1 Studio

- Right-click on the device name and select Log Off.
- In the Log Off confirmation dialog click Yes.

3.3 How to Disable a Physical Port

Using MiCOM S1 Studio or the front panel it is possible to disable unused physical ports. This can not be done by the SAT. By default, an Engineer-role is needed to perform this action.

To prevent accidental disabling of a port, a warning message is displayed according to whichever port is required to be disabled. For example if rear port 1 is to be disabled, the following message appears:

```
REAR PORT 1 TO BE
DISABLED.CONFIRM
```

There are between two and four ports eligible for disablement:

- Front port
- Rear port 1
- Rear port 2 (available in the specific models)
- Ethernet port (available in the specific models)

Important	**It is not possible to disable a port from which the disabling port command originates.**

3.4 How to Disable a Logical Port

Using MiCOM S1 Studio or the front panel it is possible to disable unused logical ports. This can’t be done by the SAT. An Engineer-role is needed to perform this action.

Caution	**Disabling the Ethernet port will disable all Ethernet based communications.**

If it is not desirable to disable the Ethernet port, it is possible to disable selected protocols on the Ethernet card and leave others functioning.

These protocols can be disabled:

- IEC61850 (available in the specific models)
- Courier Tunnelling (available in the specific models)
- IEC61850 + DNPoE (available in the specific models)

3.5 How to Secure a Function Key (When Available)

In cyber security implementation, this function has been linked to the front panel authorization.

- When the function key pressed, if there is no user login in the front panel or the logged- in user is not authorized, a prompt message will be raised in the front panel to ask the user to login. Once the user is logged-in, they need to press the function key again to execute the command.
- If the user is already logged in and the authorization is OK, the command will be executed immediately.
- By default, the OPERATOR or ENGINEER Roles are able to operate the function keys.
- The function key will be executed immediately if the auto login process is applied and the user is authorized.
- If unauthorized users press the Function Key during the setting change, they need to commit the changes first then login with authorized user to operate the function key.

4 GLOSSARY FOR CYBER SECURITY

Term	Meaning
CIP Standards	Critical Infrastructure Protection standards. NERC CIP standards have been given the force of law by the Federal Energy Regulatory Commission (FERC)
DCS	Distributed Control System
HMI	Human Machine Interface
IED	Intelligent Electronic Device. It is a power industry term to describe microprocessor-based controllers of power system equipments (e.g. Circuit breaker, transformer, etc)
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.
MIB	Management Information Base
NERC	North American Electric Reliability Corporation
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
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.
SAM	Security Administration Module. Device in charge of security management on an IP-over-Ethernet network.
SAT	Security Administration Tool TSF based application used to define and create security configuration
Secured IED	Devices embedding security mechanisms defined in the security architecture document
Security Administrator	A user of the system granted to manage its security
SNMP	Simple Network Management Protocol (SNMP) is an "Internet-standard protocol for managing devices on IP networks
TAT	Transfer Administration Tool
Unsecured IED	Relay/IEDs with no security mechanisms.

Table 15 – Glossary for cyber security

DUAL REDUNDANT ETHERNET BOARD (DREB)

CHAPTER 19

Date (month/year):	01/2017	
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:	P141/P142/P143 L P145 M P241 L P242/P243 M P342 L P343/P344/P345 M P445 L P44x (P442/P444) M P44y (P443/P446) M	P54x (P543/P544/P545/P546) M P642 L P643/P645 M P741/P743 M P742 L P746 M P841A (one circuit breaker) M P841B (two circuit breakers) M P849 M
Software Version:	P14x (P141/P142/P143/P145) B0/B2 P24x (P241/P242/P243) D0 P341 B1/E1 P34x (P342/P343/P344/P345) B0/B1 P445 B0/B1/E0/E1/J4/J6 P44x (P442/P444) E0/E1 P44y (P443/P446) H4	P54x (P543/P544/P545/P546) H4 P64x (P642/P643/P645) B1/B2 P746 B1/B2/B3 C1/C2/C3 P74x (P741/P742/P743) B0 P841A G4 P841B H4 P849 B0/B1
Connection Diagrams:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 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) P44x (P442 & P444): 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2) P445: 10P445xx (xx = 01 to 04)	P54x (P543, P544, P545 & P546): 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) P547: 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P74x (P741, P742 & P743): 10P740xx (xx = 01 to 07) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)

CONTENTS

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FIGURES

TABLES

Notes:

1 INTRODUCTION

The redundant Ethernet board assures redundancy at IED level. It is fitted into the following MiCOM IEDs from Schneider Electric.

- P141, P142, P143, P145
- P241, P242, P243
- P341, P342, P343, P344, P345
- P442, P443, P444, P445, P446
- P543, P544, P545, P546, P547
- P642, P643, P645
- P741, P743, P746
- P841, P849

1.1 Standard Safety Statements

For safety information please see the Safety Information chapter of the relevant Px4x Technical Manual.

2 HARDWARE DESCRIPTION

IEC 61850 work over Ethernet. Three boards are available:

- 1RJ45 Port Ethernet Board
- 3RJ45 Ports Redundant Ethernet Board
- 2LC+1RJ45 Ports Redundant Ethernet Board.

All are required for communications but 3RJ45 Ports and 2LC+1RJ45 Ports Redundant Ethernet Board allow an alternative path to be always available, providing bumpless redundancy.

Industrial network failure can be disastrous. Redundancy provides increased security and reliability, but also devices can be added to or removed from the network without network downtime.

The following list shows Schneider Electric's implementation of Ethernet redundancy, which has two variants with embedded IEC 61850 over Ethernet, plus PRP and HSR redundancy protocols.

- Parallel Redundancy Protocol (PRP)/High-availability Seamless Redundancy (HSR) with 1310 nm multi mode 100BaseFx fiber optic Ethernet ports (LC connector) and modulated/un- modulated IRIG-B input. Part number 2072069A01.

Note	*The board offers compatibility with any PRP/HSR device.*

- Parallel Redundancy Protocol (PRP)/High-availability Seamless Redundancy (HSR) with 100BaseTx Ethernet ports (RJ45) and modulated/un- modulated IRIG-B input. Part number 2072071A01.

Note	*The board offers compatibility with any PRP/HSR device.*

The redundant Ethernet board is fitted into Slot A of the IED, which is the optional communications slot. Each Ethernet board has three MAC addresses for two groups, one group (PORT 1) including one host MAC address, the other group (PORT 2 & 3) used for redundant application, including one host MAC address and one redundant agency device MAC address. Two host MAC addresses of the IED are printed on the rear panel of the IED.

In additional above for HSR/PRP redundant protocols, the redundant Ethernet board also can be operate on Dual IP mode. In this case, each Ethernet board has two host MAC addresses.

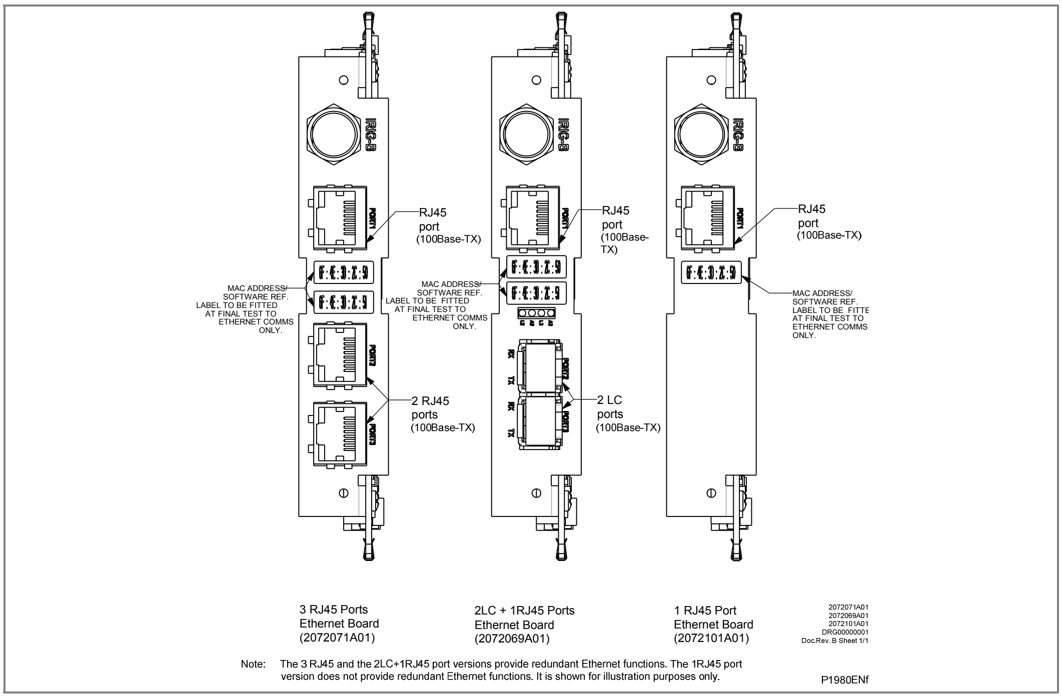

Figure 1 - Ethernet board connectors (3 RJ45 or 2 LC + RJ45 or 1 RJ45)

2.1 IRIG-B Connector

This is available as a modulated/un-modulated input.
See section 6.1.

2.2 LEDs

LED	Function	On	Off	Flashing
Green	Link	Link ok	Link broken	
Yellow	Activity			Traffic activity

Table 1 - LED functionality

2.3 Optical Fiber Connectors

Use 1310 nm multi mode 100BaseFx and LC connectors.
See Figure 1 and section 6.1.

Connector	PRP	HSR
2	Rx	Rx
2	Tx	Tx
3	Rx	Rx
3	Tx	Tx

Table 2 - Optical fiber connector functionality

3 REDUNDANCY PROTOCOLS

There are two redundancy protocols available:

- PRP (Parallel Redundancy Protocol)
- HSR (High-availability Seamless Redundancy)

3.1 Parallel Redundancy Protocol (PRP)

When the upper protocol layers send a data packet, the PRP interface creates a “twin packet” from this. The PRP interface then transmits redundant data packet of the twin pair to each participating LAN simultaneously. As they are transmitted via different LANs, the data packets may have different run times.
The receiving PRP interface forwards the first packet of a pair towards the upper protocol layers and discards the second packet. When viewed from the application, a PRP interface functions like a standard Ethernet interface.
The PRP interface or a Redundancy Box (RedBox) injects a Redundancy Control Trailer (RCT) into each packet. The RCT is a 48-bit identification field and is responsible for the identification of duplicates. This field contains, LAN identification (LAN A or B), information about the length of the payload, and a 16-bit sequence number. The PRP interface increments the sequence number for each packet sent. Using the unique attributes included in each packet, such as Physical MAC source address and sequence number, the receiving RedBox or Double Attached Node (DAN) interface identifies and discards duplicates.
Depending on the packet size, with PRP it attains a throughput of 93 to 99% of the available bandwidth.

3.1.1 PRP Network Structure

PRP uses two independent LANs. The topology of each of these LANs is arbitrary, and ring, star, bus and meshed topologies are possible.
The main advantage of PRP is loss-free data transmission with an active (transit) LAN. When the terminal device receives no packets from one of the LANs, the second (transit) LAN maintains the connection. As long as 1 (transit) LAN is available, repairs and maintenance on the other (transit) LAN have no impact on the data packet transmission.
The elementary devices of a PRP network are known as RedBox (Redundancy Box) and DANP (Double Attached Node implementing PRP).
Both devices have one connection each to the (transit) LANs.
The devices in the (transit) LAN are conventional switches that do not require any PRP support. The devices transmit PRP data packets transparently, without evaluating the RCT information.
Terminal devices that are connected directly to a device in the (transit) LAN are known as SAN (Single Attached Node). If there is an interruption, these terminal devices cannot be reached via the redundant line. To use the uninterruptible redundancy of the PRP network, you integrate your device into the PRP network via a RedBox.

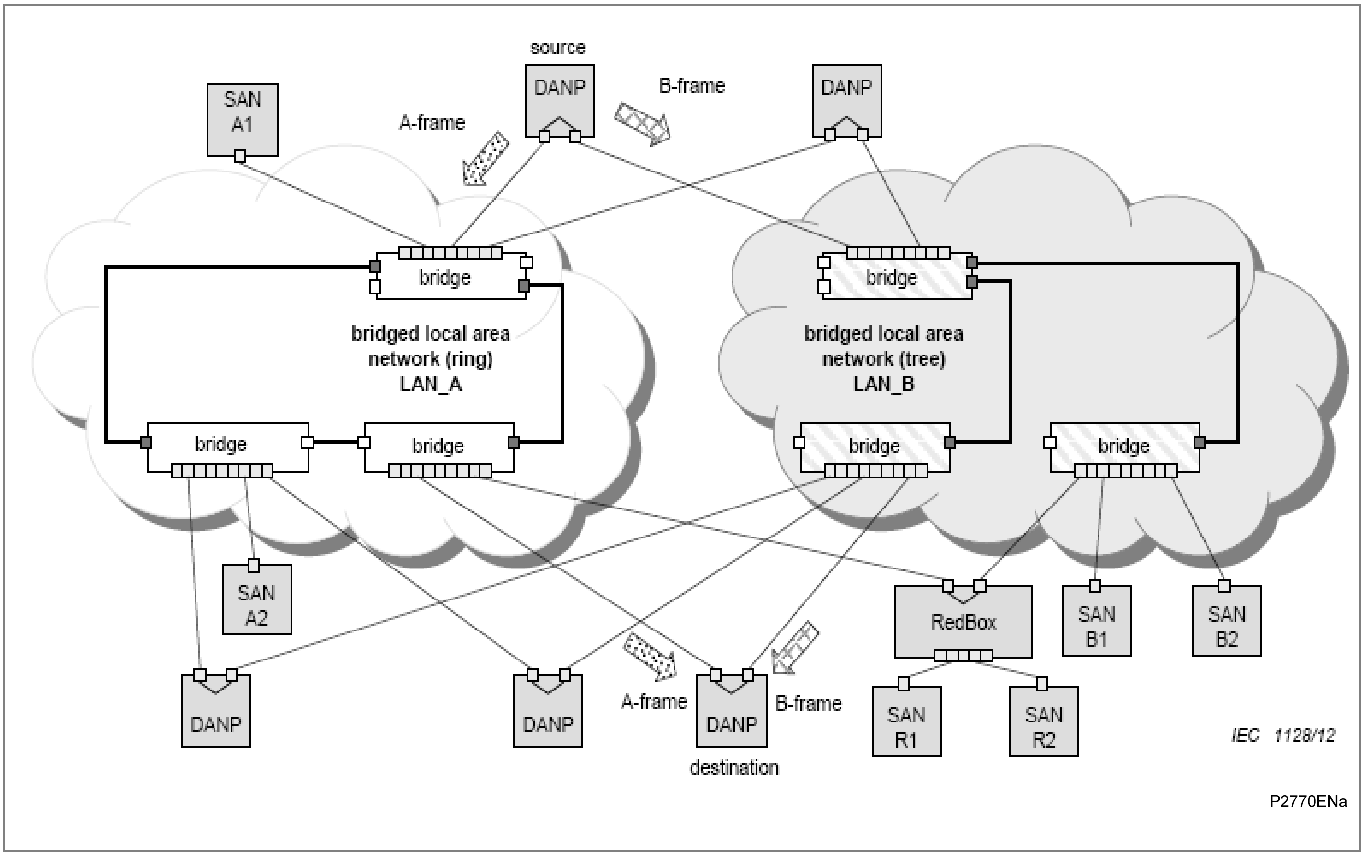

Figure 2 - PRP example of general redundant network

3.1.2 Example Configuration

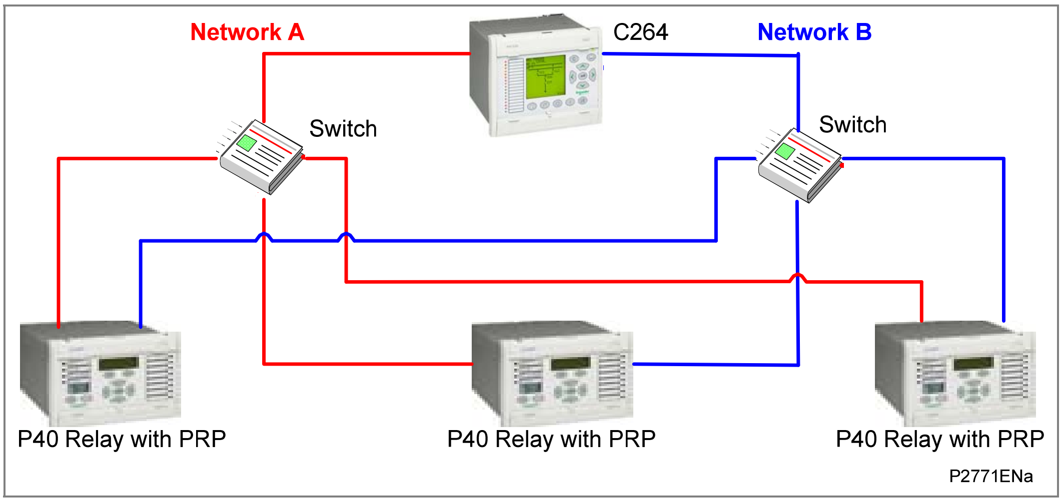

Figure 3 - PRP Relay Configuration

3.2 High-availability Seamless Redundancy (HSR)

High-availability Seamless Redundancy (HSR) can only be used in a ring topology, This section describes the application of the PRP principles (IEC 62439-3- Clause 4) to implement a High-availability Seamless Redundancy (HSR), retaining the PRP property of zero recovery time, applicable to rings. With respect to PRP, HSR allows you to greatly reduce the network infrastructure. With respect to rings based on IEEE 802.1D (RSTP), IEC 62439-2 (MRP), IEC 62439-6 (DRP) or IEC 62439-7 (RRP), the available network bandwidth for network traffic is somewhat reduced depending on the type of traffic. Nodes within the ring are restricted to be HSR-capable bridging nodes, thus avoiding the use of dedicated bridges. Singly Attached Nodes (SANs) such as laptops or printers cannot be attached directly to the ring, but need attachment through a RedBox (redundancy box).

3.2.1 HSR Network Structure

As in PRP, a node has two ports operated in parallel; it is a DANH (Doubly Attached Node with HSR protocol).
A simple HSR network consists of doubly-attached bridging nodes, each having two ring ports, interconnected by full-duplex links, as shown in these examples for a ring topology:

- Figure 4 (multicast)
- Figure 5 (unicast)

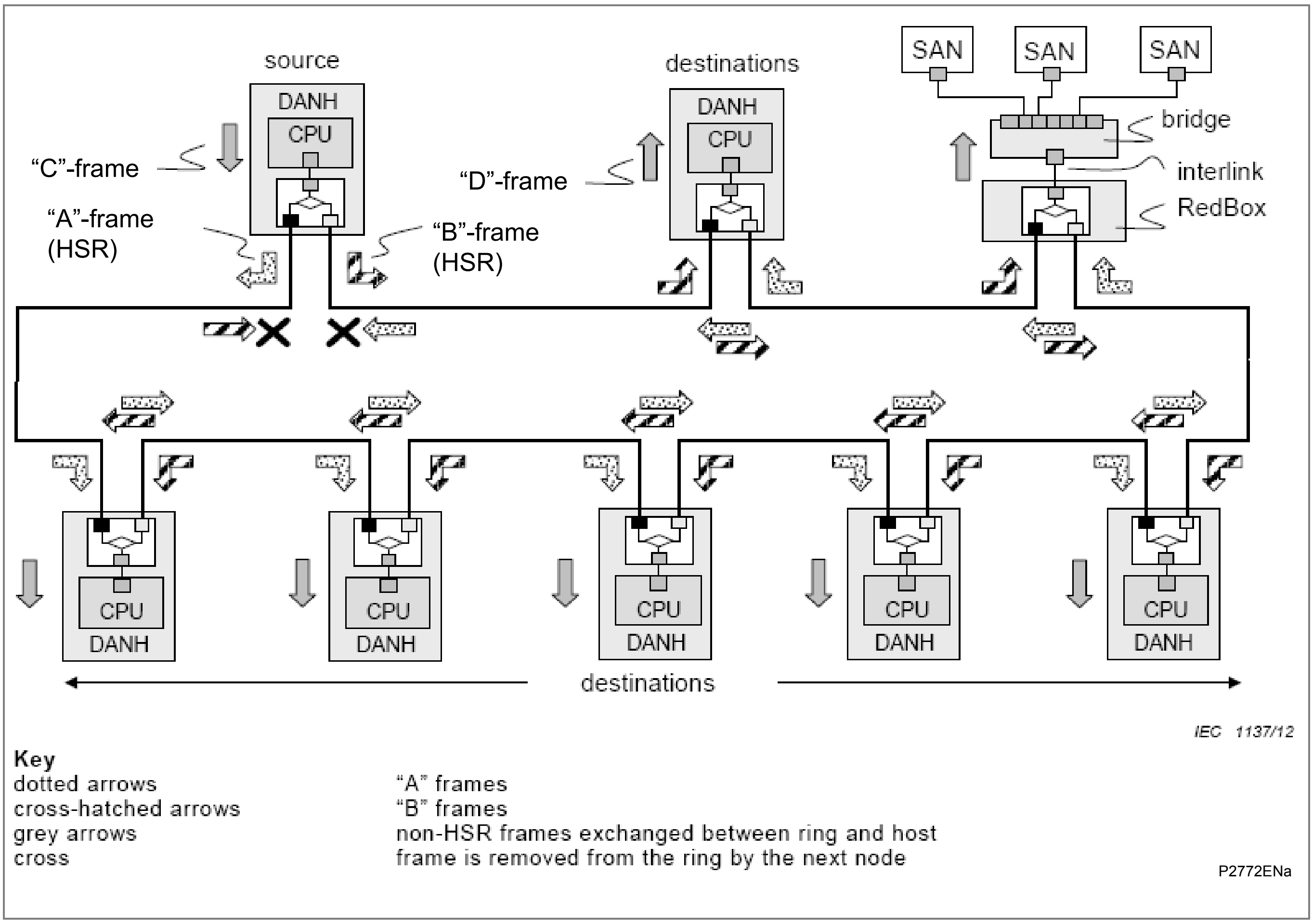

Figure 4 - HSR example of ring configuration for multicast traffic

A source DANH sends a frame passed from its upper layers ("C" frame), prefixes it by an HSR tag to identify frame duplicates and sends the frame over each port ("A"-frame and "B"-frame). A destination DANH receives, in the fault-free state, two identical frames from each port within a certain interval, removes the HSR tag of the first frame before passing it to its upper layers ("D"-frame) and discards any duplicate.
The nodes support the IEEE 802.1D bridge functionality and forward frames from one port to the other, except if they already sent the same frame in that same direction.
In particular, the node will not forward a frame that it injected into the ring.

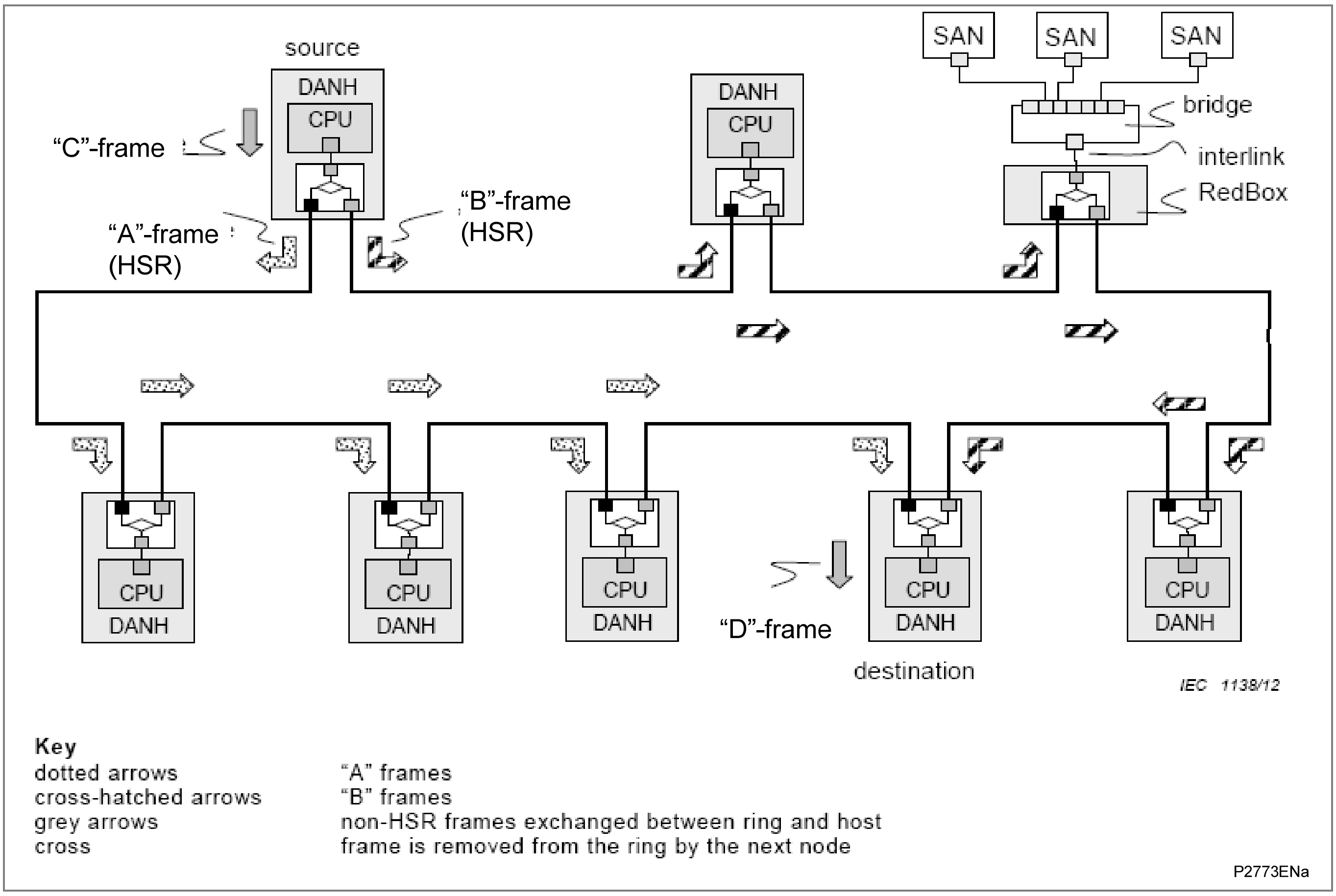

Figure 5 - HSR example of ring configuration for unicast traffic

A destination node of a unicast frame does not forward a frame for which it is the only destination, except for testing.
Frames circulating in the ring carry the HSR tag inserted by the source, which contains a sequence number. The doublet {source MAC address, sequence number} uniquely identifies copies of the same frame.
Singly Attached Nodes (SANs), for instance maintenance laptops or printers cannot be inserted directly into the ring since they have only one port and cannot interpret the HSR tag in the frames. SANs communicate with ring devices through a RedBox (redundancy box) that acts as a proxy for the SANs attached to it, as shown in the diagram.
Connecting non-HSR nodes to ring ports, breaking the ring, is allowed to enable configuration. Non-HSR traffic within the closed ring is supported in an optional mode.

3.2.2 Example Configuration

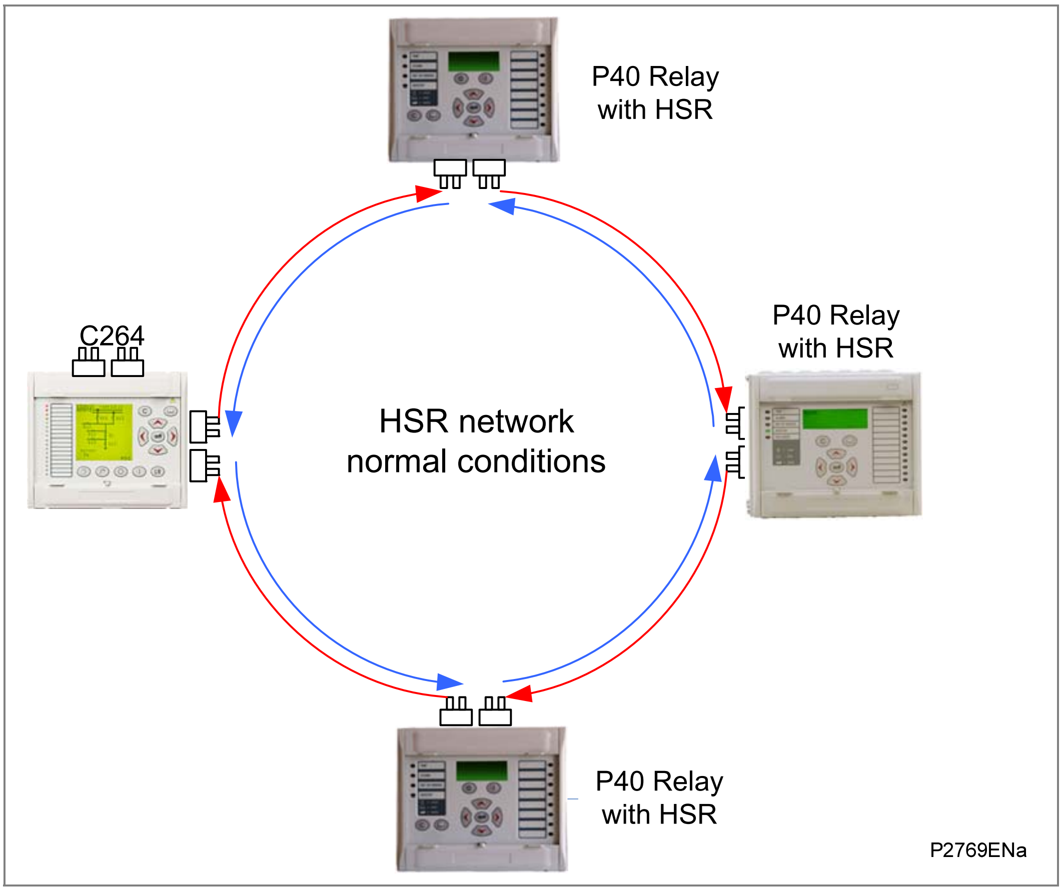

Figure 6 - HSR Relay Configuration

3.3 Generic Functions for all Redundant Ethernet Boards

The following apply to the redundant Ethernet protocols (PRP and HSR).

3.3.1 Priority Tagging

802.1p priority is enabled on all ports.

3.3.2 Simple Network Management Protocol (SNMP)

Simple Network Management Protocol (SNMP) is the network protocol developed to manage devices in an IP network. SNMP relies on a Management Information Base (MIB) that contains information about parameters to supervise. The MIB format is a tree structure, with each node in the tree identified by a numerical Object IDentifier (OID). Each OID identifies a variable that can be read or set using SNMP with the appropriate software. The information in the MIBs is standardized.

3.3.2.1 Redundant Ethernet Board MIB Structure

The IEC 62439-3 MIB provides the following objects available at the OID = .1.0.62439:

SNMP OID	Parameter name	Description
1	iso	
1	std	
1.0.62439	iec62439	
1.0.62439.2	prp	
1.0.62439.2.0	linkRedundancyEntityNotifications	
1.0.62439.2.1	linkRedundancyEntityObjects	
1.0.62439.2.1.0	lreConfiguration	
1.0.62439.2.1.0.0	lreConfigurationGeneralGroup	
1.0.62439.2.1.0.0.1	lreManufacturerName	Specifies the name of the LRE device manufacturer
1.0.62439.2.1.0.0.2	lreInterfaceCount	Total number of LREs present in this system
1.0.62439.2.1.0.1	lreConfigurationInterfaceGroup	
1.0.62439.2.1.0.1.0	lreConfigurationInterfaces	
1.0.62439.2.1.0.1.0.1	lreInterfaceConfigTable	List of PRP/HSR LREs. Each entry corresponds to one PRP/HSR Link Redundancy Entity (LRE), each representing a pair of LAN ports A and B. Basic devices supporting PRP/HSR may have only one LRE and thus one entry in the table, while more complex devices may have several entries for multiple LREs
1.0.62439.2.1.0.1.0.1.1	lreInterfaceConfigEntry	Each entry contains management information
1.0.62439.2.1.0.1.0.1.1.1	lreInterfaceConfigIndex	A unique value for each LRE
1.0.62439.2.1.0.1.0.1.1.2	lreRowStatus	Indicates the status of the LRE table entry
1.0.62439.2.1.0.1.0.1.1.3	lreNodeType	Specifies the operation mode of the LRE: PRP mode 1 (1) HSR mode (2). Note: PRP mode 0 is considered deprecated and is not supported by this revision of the MIB
1.0.62439.2.1.0.1.0.1.1.4	lreNodeName	Specifies this LRE's node name
1.0.62439.2.1.0.1.0.1.1.5	lreVersionName	Specifies the version of this LRE's software
1.0.62439.2.1.0.1.0.1.1.6	lreMacAddress	Specifies the MAC address to be used by this LRE. MAC addresses are identical for all ports of a single LRE
1.0.62439.2.1.0.1.0.1.1.7	lrePortAdminStateA	Specifies whether the port A shall be active or not Active through administrative action (Default: active)
1.0.62439.2.1.0.1.0.1.1.8	lrePortAdminStateB	Specifies whether the port B shall be active or not Active through administrative action (Default: active)
1.0.62439.2.1.0.1.0.1.1.9	lreLinkStatusA	Shows the actual link status of the LRE's port A
1.0.62439.2.1.0.1.0.1.1.10	lreLinkStatusB	Shows the actual link status of the LRE's port B

SNMP OID	Parameter name	Description
1.0.62439.2.1.0.1.0.1.1.11	lreDuplicateDiscard	Specifies whether a duplicate discard algorithm is used at reception (Default: discard)
1.0.62439.2.1.0.1.0.1.1.12	lreTransparentReception	If removeRCT is configured, the RCT is removed when forwarding to the upper layers, only applicable for PRP LRE (Default: removeRCT)
1.0.62439.2.1.0.1.0.1.1.13	lreHsrLREMode	This enumeration is only applicable if the LRE is an HSR bridging node or RedBox. It shows the mode of the HSR LRE: (1) Default mode: The HSR LRE is in mode h and bridges tagged HSR traffic (2) Optional mode: The HSR LRE is in mode n and bridging between its HSR ports is disabled. Traffic is HSR tagged (3) Optional mode: The HSR LRE is in mode t and bridges non-tagged HSR traffic between its HSR ports (4) Optional mode: The HSR LRE is in mode u and behaves like in mode h, except it does not remove unicast messages (5) Optional mode: The HSR LRE is configured in mixed mode. HSR frames are handled according to mode h. Non-HSR frames are handled according to 802.1D bridging rules
1.0.62439.2.1.0.1.0.1.1.14	lreSwitchingEndNode	This enumeration shows which feature is enabled in this particular LRE: (1): an unspecified non-bridging node, e.g. SRP. (2): an unspecified bridging node, e.g. RSTP. (3): a PRP node/RedBox. (4): an HSR RedBox with regular Ethernet traffic on its interlink. (5): an HSR switching node. (6): an HSR RedBox with HSR tagged traffic on its interlink. (7): an HSR RedBox with PRP traffic for LAN A on its interlink. (8): an HSR RedBox with PRP traffic for LAN B on its interlink.
1.0.62439.2.1.0.1.0.1.1.15	lreRedBoxIdentity	Applicable to RedBox HSR-PRP A and RedBox HSR-PRP B. One ID is used by one pair of RedBoxes (one configured to A and one configured to B) coupling an HSR ring to a PRP network. The integer value states the value of the path field a RedBox inserts into each frame it receives from its interlink and injects into the HSR ring. When interpreted as binary values, the LSB denotes the configuration of the RedBox (A or B), and the following 3 bits denote the identifier of a RedBox pair.
1.0.62439.2.1.0.1.0.1.1.16	lreEvaluateSupervision	True if the LRE evaluates received supervision frames. False if it drops the supervision frames without evaluating. Note: LREs are required to send supervision frames, but reception is optional. Default value is dependent on implementation.
1.0.62439.2.1.0.1.0.1.1.17	lreNodesTableClear	Specifies that the Node Table is to be cleared
1.0.62439.2.1.0.1.0.1.1.18	lreProxyNodeTableClear	Specifies that the Proxy Node Table is to be cleared
1.0.62439.2.1.1	lreStatistics	
1.0.62439.2.1.1.1	lreStatisticsInterfaceGroup	
1.0.62439.2.1.1.1.0	lreStatisticsInterfaces	
1.0.62439.2.1.1.1.0.1	lreInterfaceStatsTable	List of PRP/HSR LREs. Each entry corresponds to one PRP/HSR Link Redundancy Entity (LRE), each representing a pair of LAN ports A and B and a port C towards the application/interlink. Basic devices supporting PRP/HSR may have only one LRE and thus one entry in the table, while more complex devices may have several entries for multiple LREs.
1.0.62439.2.1.1.1.0.1.1	lreInterfaceStatsEntry	An entry containing management information applicable to a particular LRE
1.0.62439.2.1.1.1.0.1.1.1	lreInterfaceStatsIndex	A unique value for each LRE
1.0.62439.2.1.1.1.0.1.1.2	lreCntTxA	Number of frames sent over port A that are HSR tagged or fitted with a PRP Redundancy Control Trailer. Only frames that are HSR tagged or do have a PRP RCT are counted. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.3	lreCntTxB	Number of frames sent over port B that are HSR tagged or fitted with a PRP Redundancy Control Trailer. Only frames that are HSR tagged or do have a PRP RCT are counted. Initial value = 0.

SNMP OID	Parameter name	Description
1.0.62439.2.1.1.1.0.1.1.4	lreCntTxC	Number of frames sent towards the application interface of the DANP or DANH or over the interlink of the RedBox. All frames (with our without PRP RCT or HSR tag) are counted. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.5	lreCntErrWrongLanA	Number of frames with the wrong LAN identifier received on LRE port A. Initial value = 0. Only applicable to PRP ports.
1.0.62439.2.1.1.1.0.1.1.6	lreCntErrWrongLanB	Number of frames with the wrong LAN identifier received on LRE port B. Initial value = 0. Only applicable to PRP ports
1.0.62439.2.1.1.1.0.1.1.7	lreCntErrWrongLanC	Number of frames with the wrong LAN identifier received on the interlink of a RedBox. Only applicable to HSR RedBoxes in HSR-PRP configuration (hsrredboxprpa and hsrredboxprpb).
1.0.62439.2.1.1.1.0.1.1.8	lreCntRxA	Number of frames received on a LRE port A. Only frames that are HSR tagged or fitted with a PRP Redundancy Control Trailer are counted. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.9	lreCntRxB	Number of frames received on a LRE port B. Only frames that are HSR tagged or fitted with a PRP Redundancy Control Trailer are counted. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.10	lreCntRxC	Number of frames received from the application interface of a DANP or DANH or the number of number of frames received on the interlink of a RedBox. All frames (with our without PRP RCT or HSR tag) are counted. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.11	lreCntErrorsA	Number of frames with errors received on this LRE port A. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.12	lreCntErrorsB	Number of frames with errors received on this LRE port B. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.13	lreCntErrorsC	Number of frames with errors received on the application interface of a DANP or DANH or on the interlink of a RedBox. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.14	lreCntNodes	Number of nodes in the Nodes Table
1.0.62439.2.1.1.1.0.1.1.15	lreCntProxyNodes	Number of nodes in the Proxy Node Table. Only applicable to RedBox. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.16	lreCntUniqueRxA	Number of entries in the duplicate detection mechanism on port A for which no duplicate was received. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.17	lreCntUniqueRxB	Number of entries in the duplicate detection mechanism on port B for which no duplicate was received. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.18	lreCntUniqueRxC	Number of entries in the duplicate detection mechanism on the application interface of the DAN or the interlink of the RedBox for which no duplicate was received. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.19	lreCntDuplicateRxA	Number of entries in the duplicate detection mechanism on port A for which one single duplicate was received. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.20	lreCntDuplicateRxB	Number of entries in the duplicate detection mechanism on port B for which one single duplicate was received. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.21	lreCntDuplicateRxC	Number of entries in the duplicate detection mechanism on the application interface of the DAN or the interlink of the RedBox for which one single duplicate was received. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.22	lreCntMultiRxA	Number of entries in the duplicate detection mechanism on port A for which more than one duplicate was received. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.23	lreCntMultiRxB	Number of entries in the duplicate detection mechanism on port B for which more than one duplicate was received. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.24	lreCntMultiRxC	Number of entries in the duplicate detection mechanism on the application interface of the DAN or the interlink of the RedBox for which more than one duplicate was received. Initial value = 0
1.0.62439.2.1.1.1.0.1.1.25	lreCntOwnRxA	Number of HSR tagged frames received on Port A that originated from this device. Frames originate from this device if the source MAC matches the MAC of the LRE, or if the source MAC appears in the proxy node table (if implemented). Applicable only to HSR. Initial value = 0.
1.0.62439.2.1.1.1.0.1.1.26	lreCntOwnRxB	Number of HSR tagged frames received on Port B that originated from this device. Frames originate from this device if the source MAC matches the MAC of the LRE, or if the source MAC appears in the proxy node table (if implemented). Applicable only to HSR. Initial value = 0.

SNMP OID	Parameter name	Description
1.0.62439.2.1.1.1.0.2	lreNodesTable	The node table (if it exists on that node) contains information about all remote LRE, which advertised themselves through supervision frames
1.0.62439.2.1.1.1.0.2.1	lreNodesEntry	Each entry in the node table (if it exists) contains information about a particular remote LRE registered in the node table, which advertised itself through supervision frames.
1.0.62439.2.1.1.1.0.2.1.1	lreNodesIndex	Unique value for each node in the LRE's node table
1.0.62439.2.1.1.1.0.2.1.2	lreNodesMacAddress	Each MAC address corresponds to a single Dual Attached Node
1.0.62439.2.1.1.1.0.2.1.3	lreTimeLastSeenA	Time in TimeTicks (1/100s) since the last frame from this remote LRE was received over LAN A. Initialized with a value of 0 upon node registration in the node table
1.0.62439.2.1.1.1.0.2.1.4	lreTimeLastSeenB	Time in TimeTicks (1/100s) since the last frame from this remote LRE was received over LAN B. Initialized with a value of 0 upon node registration in the node table.
1.0.62439.2.1.1.1.0.2.1.5	lreRemNodeType	DAN type, as indicated in the received supervision frame
1.0.62439.2.1.1.1.0.3	lreProxyNodeTable	The proxy node table (if implemented) contains information about all nodes, for which the LRE acts as a connection to the HSR/PRP network.
1.0.62439.2.1.1.1.0.3.1	lreProxyNodeEntry	Each entry in the proxy node table contains information about a particular node for which the LRE acts as a connection to the HSR/PRP network.
1.0.62439.2.1.1.1.0.3.1.1	lreProxyNodeIndex	A unique value for each node in the LRE's proxy node table.
1.0.62439.2.1.1.1.0.3.1.2	lreProxyNodeMacAddress	Each entry contains information about a particular node for which the LRE acts as a proxy for the HSR/PRP network.
1.0.62439.2.2	linkRedundancyEntityConformance	

Table 3 - Redundant Ethernet board MIB Structure

*Port number: 1 to 6 for the RJ45, port 7 management, port 8 ring

Various SNMP client software tools can be used with the MiCOM Px4x, C264 and Hx8x range. Schneider Electric recommends using an SNMP MIB browser which can perform the basic SNMP operations such as GET, GETNEXT, and RESPONSE.

Redundant agency device configuration will be required to access SNMP, refer to section 4.4 for more details.

3.3.3 Simple Network Time Protocol (SNTP)

Simple Network Time Protocol (SNTP) is supported by both the IED and the redundant Ethernet switch. SNTP is used to synchronize the clocks of computer systems over packet-switched, variable-latency data networks. A jitter buffer is used to reduce the effects of variable latency introduced by queuing in packet switched networks, ensuring a continuous data stream over the network.

The IED receives the synchronization from the SNTP server. This is done using the IP address of the SNTP server entered into the IED from the IED Configurator software.

3.3.4 Dual Ethernet Communication (Dual IPs)

3.3.4.1 Dual IP Introduction

Dual IP means the IED provides two independent IEC 61850 interfaces, and both these interfaces support MMS and Goose message.

The IED which supports Dual IP can provide the customer with more flexible network connections: two fully segregated Station BUS networks, or one Station Bus and one Process Bus (for Goose message transmission).

Dual IP is not mutually exclusive with PRP/HSR - Dual IP is automatically supported even if the IED is operate under HSR/PRP mode.

3.3.4.2 Dual IP in MiCOM

Dual IP is only supported for devices with the new Ethernet board assembly. This is shown by the model number, where the 7th digit is either hardware option Q or R. These boards have three Ethernet ports, as shown in Figure 1.

A setting is provided in the HMI to switch the operation mode between PRP/HSR/Dual IP.

Operation mode	Port 1	Port 2	Port3
PRP	Interface 1	Interface 2 (PRP)	Interface 2 (PRP)
HSR	Interface 1	Interface 2 (HSR)	Interface 2 (HSR)
Dual IP	* Interface 1 on Port 1 or Port 2		Interface 2

** Note* *In Dual IP mode, interface 1 can be available on port 1 or port 2. If both of port 1 and port 2 are connected, only port 1 will work.*

Table 4 - Ethernet ports operation mode

For each interface, the fully IEC 61850 functions (GOOSE and MMS services) are supported independently.

For outgoing GOOSE messages, you need to configure whether a message is to be transmitted across one or both Ethernet connections. You also need to configure the destination parameters such as multicast MAC address, AppID, VLAN, etc.

Two communication parameters also need to be configured for each interface (IP address, MAC address, subnet mask). For the CID which is exported from SCD file, the second interface communication parameters are not configured. This needs to be done by manually editing in the IED configurator (this being invisible by the SCD file). This process needs to be completed before the exported CID file is downloaded to the IED. (this being invisible by the SCD file).

3.3.4.3 **Typical User Cases**

Below for Interface 1 and Interface 2, from a functional point of view it is same. The customer has flexibility to define the functionality according their requirements.

- Both for Station Bus to have duplicated network for DCS.
- One for Station Bus and one for process bus (Goose message)

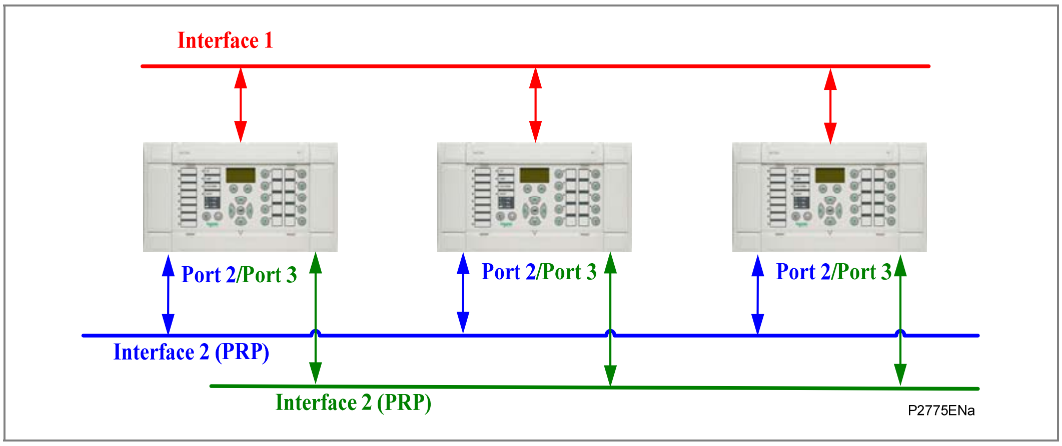

Figure 7 - PRP + Dual IP (Ethernet Mode PRP)

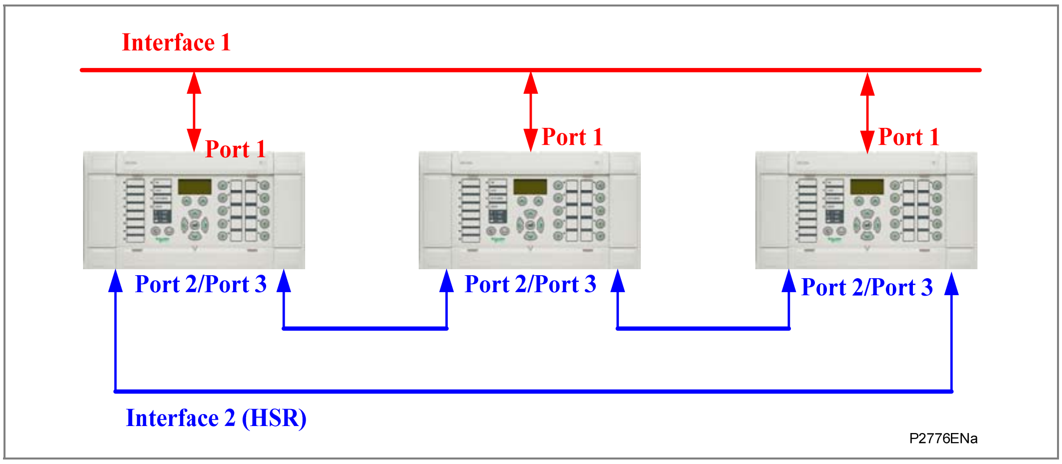

Figure 8 - HSR + Dual IP (Ethernet Mode HSR)

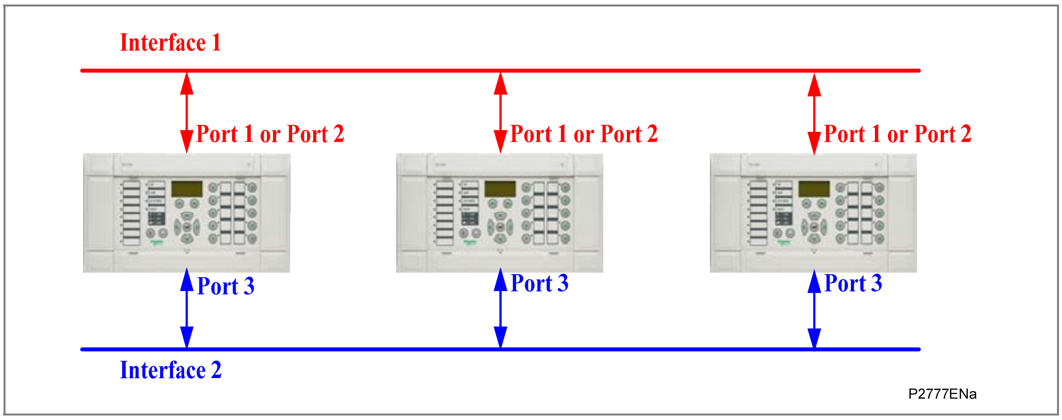

Figure 9 - Dual IP (Ethernet Mode Dual IP)

4 CONFIGURATION

The new redundant Ethernet board supports three communication operation modes. These can be achieved by change the setting in HMI. It is not necessary to flash the firmware.

Also for the two interfaces, the communication parameters need to be configured. These include the IP address, MAC address, and subnet mask, etc.

For redundant protocols, the communication parameters for redundant agency device also need to be configured.

4.1 Configuring Ethernet Communication Mode

Menu Text	Cell Add.	Default Setting	Available Setting
ETH COMM Mode	0016	Dual IP	Dual IP, PRP, HSR
This setting can only be change using the HMI, and the setting change will cause the Ethernet board reboot. Restore default setting does not apply to this setting.			

Table 5 - Ethernet communication mode setting

4.2 Configuring the IED Communication Parameters

The communication parameter for each interface is configured using the IED Configurator software in MiCOM S1 Studio. **Customers can configure these parameters according to their needs, but the IP address for these two interfaces should not be in the same subnet.**

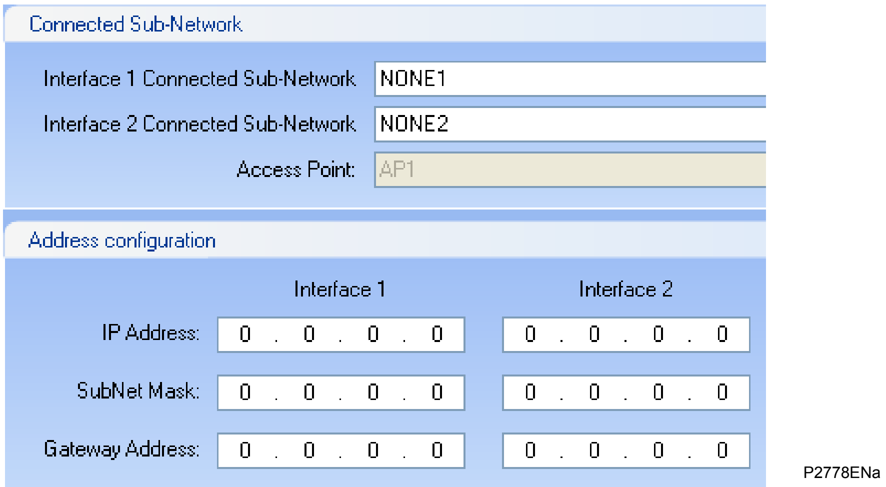

Figure 10 - Communication Parameters for two Interfaces

To use the device configuration with Courier Tunneling, for each interface, a default IP address has been applied. The default IP address for the first three bytes is fixed for each interface as below,

Interface	First three Bytes for IP address
Interface 1	169.254.0.xxx
Interface 2	169.254.1.yyy

Note *xxx = Mod(The last byte MAC1 address, 128) + 1*
yyy = Mod(The last byte MAC2 address, 128) + 1

Table 6 - First three bytes for default IP address

The default IP address can be found in the ***IED CONFIGURATOR*** column. Also, you can also calculate it according the MAC address label which is mounted on the rear panel of the Ethernet card.

4.3 Configuring GOOSE Publish Parameters

For outgoing GOOSE messages, you need to configure whether a message is to be transmitted over one or both Ethernet connections. You also need to configure the destination parameters including multicast MAC address, AppID, VLAN, etc.

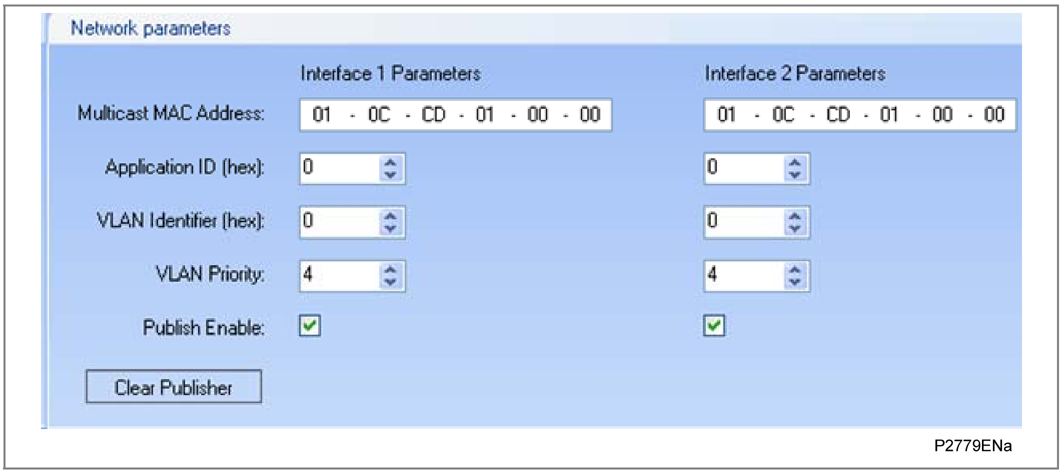

Figure 11 - Goose Publish Parameters for two Interfaces

4.4 Redundant Agency Device Configuration

The redundant agency device configuration is used by the SNMP server and only available for the device which works on PRP/HSR mode. The SNMP server can only be connected with Interface 2 (HSR/PRP port).

The following settings need to be configured in setting files:

- IP address
- Subnet Mask
- Gateway.

The MAC address is set when the device is manufactured. Also, the default IP is applied and linked to the MAC address. This default IP address can be seen in the HMI, in the Communication settings section.

The default IP address is 169.254.2.zzz.

zzz = Mod (The last byte MAC3 address, 128) + 1

5 COMMISSIONING

5.1 PRP Star Connection

The following diagram shows the Px4x IEDs with the PRP variant of Redundant Ethernet boards connected in a STAR topology. The STAR topology can have one or more high-end PRP-enabled Ethernet switches to interface with another network. The Ethernet switch is an HSR-enabled switch with a higher number of ports, which should be configured as the root bridge.

The number of IEDs that can be connected in the STAR can be up to 128.

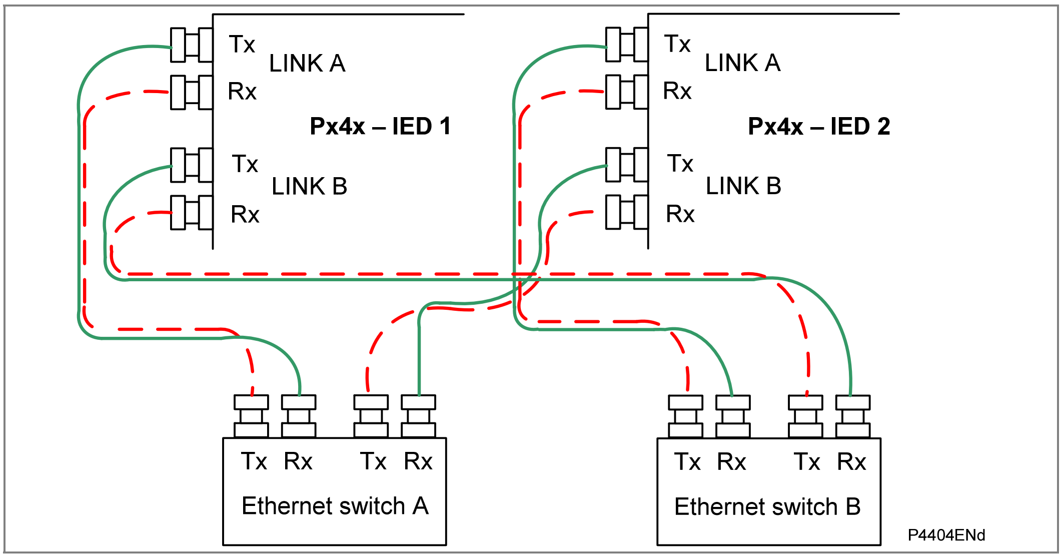

Figure 12 - PRP star connection

5.2 HSR Ring Connection

The following diagram shows the Px4x IEDs (Px4x - IED 1 to IED N) with the HSR variant of redundant Ethernet boards connected in a ring topology. The ring topology can have one or more high-end HSR-enabled Ethernet switches to interface with another network or a control center. The Ethernet switch is an HSR enabled switch with a higher number of ports.

The Ethernet switch, which is connected to the controlling PC, should be configured as the root bridge.

The number of IEDs that can be connected in the ring can be up to 128.

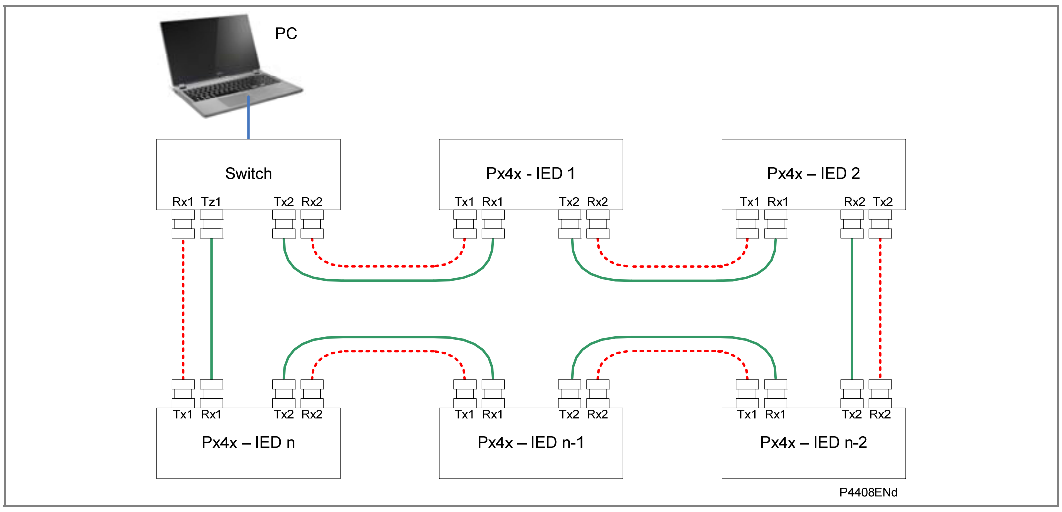

Figure 13 - HSR ring topology

The number of IEDs that can be connected in the ring can be up to 128.

6 TECHNICAL DATA

The technical data applies to a Redundant Ethernet board fitted into these MiCOM products.

- P141, P142, P143, P145
- P241, P242, P243
- P341, P342, P343, P344, P345
- P442, P443, P444, P445, P446
- P543, P544, P545, P546, P547
- P642, P643, P645
- P741, P743, P746
- P841, P849

6.1 Board Hardware

6.1.1 100 Base TX Communications Interface (in accordance with IEEE802.3 and IEC 61850)

Cable type	Screened Twisted Pair (STP)
Connector type	RJ45
Maximum distance	100m
Full Duplex	100 Mbps

Table 7 - 100 Base TX interface

6.1.2 100 Base FX Communications Interface (in accordance with IEEE802.3 and IEC 61850)

Optical fiber cable	Multi-mode 50/125 µm or 62.5/125 µm
Center wavelength	1310 nm
Connector type	LC
Maximum distance	2 km
Full Duplex	100 Mbps

Table 8 - 100 Base FX interface

6.1.3 Transmitter Optical Characteristics

(TA = -40° C to 85° C)

Parameter	Sym	Min.	Typ.	Max.	Unit
Output Optical Power 62.5/125 µm, NA = 0.275 Fiber	PO	-20	-17.0	-14	dBm avg.
Output Optical Power 50/125 µm, NA = 0.20 Fiber	PO	-23.5	-20.0	-14	dBm avg.
Optical Extinction Ratio				10	dB
Output Optical Power at Logic “0” State	PO (“0”)			-45	dBm avg.

Table 9 - Tx optical characteristics

6.1.4 Receiver Optical Characteristics

(TA = -40° C to 85° C)

Parameter	Sym	Min.	Typ.	Max.	Unit
Input Optical Power	PIN	-31		-14	dBm avg.

Table 10 - Rx optical characteristics

6.1.5 IRIG-B and Real-Time Clock

6.1.5.1 Performance

Year 2000:	Compliant
Real time accuracy:	< ±2 seconds / day
External clock synchronization:	Conforms to IRIG standard 200-98, format B

6.1.5.2 Features

Real time 24 hour clock settable in hours, minutes and seconds
Calendar settable from January 1994 to December 2092
Clock and calendar maintained via battery after loss of auxiliary supply
Internal clock synchronization using IRIG-B Interface for IRIG-B signal is BNC

6.1.5.3 Self-adapted Rear IRIG-B interface (Modulated or Unmodulated)

BNC plug
Isolation to SELV level
50 ohm coaxial cable

6.2 Type Tests

6.2.1 Insulation

Per EN / IEC 60255-27:
Insulation resistance > 100 MΩ at 500 Vdc
(Using only electronic/brushless insulation tester).

6.2.2 Creepage Distances and Clearances

Per EN / IEC 60255-27:
Pollution degree 3, Overvoltage category III,

6.2.3 High Voltage (Dielectric) Withstand

(EIA RS-232 ports excepted and normally-open contacts of output relays excepted).

(i) As for EN / IEC 60255-27:

2 kV rms AC, 1 minute:
Between all independent circuits.
Between independent circuits and case earth (ground).
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.
1 kV rms AC for 1 minute for all D-type EIA(RS)-232 or EIA(RS)-485 ports between the communications port terminals and protective (earth) conductor terminal.
1 kV rms AC for 1 minute between RJ45 ports and the case earth (ground).

(ii) As for ANSI/IEEE C37.90:

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

6.2.4 Impulse Voltage Withstand Test

As for EN / IEC 60255-27:

(i) Front time: 1.2 µs, Time to half-value: 50 µs,
Peak value: 5 kV, 0.5 J
Between all independent circuits.
Between independent circuits and case earth ground.

(ii) Front time: 1.2 µs, Time to half-value: 50 µs,
Peak value: 1.5kV, 0.5 J
Between RJ45 ports and the case earth (ground).
EIA(RS)-232 & EIA(RS)-485 ports and normally open contacts of output relays excepted.

6.3 ElectroMagnetic Compatibility (EMC)

6.3.1 1 MHz Burst High Frequency Disturbance Test

As for EN / IEC 60255-22-1, 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).

6.3.2 100 kHz and 1MHz Damped Oscillatory Test

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

6.3.3 Immunity to Electrostatic Discharge

As for EN / IEC 60255-22-2, EN / IEC 61000-4-2:

15kV discharge in air to user interface, display, communication ports and exposed metalwork.
6kV contact discharge to the screws on the front of the front communication ports.
8kV point contact discharge to any part of the front of the product.

6.3.4 Electrical Fast Transient or Burst Requirements

As for EN / IEC 60255-22-4, Class B:

±4.0 kV, 5kHz and 100kHz applied to all inputs / outputs excluding communication ports
±2.0 kV, 5kHz and 100kHz applied to all communication ports

As for EN / IEC 61000-4-4, severity level 4:

±2.0 kV, 5kHz and 100kHz applied to all inputs / outputs and communication ports excluding power supply and earth.
±4.0 kV, 5kHz and 100kHz applied to all power supply and earth port

Rise time of one pulse:	5 ns
Impulse duration (50% value):	50 ns
Burst duration:	15 ms or 0.75ms
Burst cycle:	300 ms
Source impedance:	50 Ω

6.3.5 Surge Withstand Capability

As for IEEE/ANSI C37.90.1:
4 kV fast transient and 2.5 kV oscillatory
applied directly across each output contact, optically isolated input, and power supply circuit.

6.3.6 Surge Immunity Test

As for EN / IEC 61000-4-5, EN / IEC 60255-26:
Time to half-value: 1.2 to 50 µs,
Amplitude: 4 kV between all groups and case earth (ground),
Amplitude: 2 kV between terminals of each group.
Amplitude: 1kV for LAN ports

6.3.7 Conducted/Radiated Immunity

For RTDs used for tripping applications the conducted and radiated immunity performance is guaranteed only when using totally shielded RTD cables (twisted leads).

6.3.8 Immunity to Radiated Electromagnetic Energy

Per EN / IEC 61000-4-3 and EN / IEC 60255-22-3, Class 3
Test field strength, frequency band 80 to 1000 MHz and
1.4 GHz to 2.7GHz: 10 V/m,
Test using AM: 1 kHz / 80%, Spot tests at 80, 160, 450, 900, 1850, 2150 MHz
Per IEEE/ANSI C37.90.2:
80MHz to 1000MHz, zero and 100% square wave modulated.
Field strength of 35V/m.

6.3.9 Radiated Immunity from Digital Communications

As for EN / IEC61000-4-3, 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%.

6.3.10 Radiated Immunity from Digital Radio Telephones

As for EN / IEC 61000-4-3: 10 V/m, 900 MHz and 1.89 GHz.

6.3.11 Immunity to Conducted Disturbances Induced by Radio Frequency Fields

As for EN / IEC 61000-4-6, Level 3, Disturbing test voltage: 10 V.

6.3.12 Power Frequency Magnetic Field Immunity

As for EN / IEC 61000-4-8, Level 5,
100 A/m applied continuously, 1000 A/m applied for 3 s.
As for EN / IEC 61000-4-9, Level 5,
1000 A/m applied in all planes.
As for EN / IEC 61000-4-10, Level 5,
100 A/m applied in all planes at 100 kHz and 1 MHz with a burst duration of 2 s.

6.3.13 Conducted Emissions

As for CISPR 22 Class A:
Power supply:
0.15 - 0.5 MHz, 79 dBµV (quasi peak) 66 dBµV (average)
0.5 - 30 MHz, 73 dBµV (quasi peak) 60 dBµV (average)
Permanently connected communications ports:
0.15 - 0.5MHz, 97dBµV (quasi peak) 84dBµV (average)
0.5 - 30MHz, 87dBµV (quasi peak) 74dBµV (average)

6.3.14 Radiated Emissions

As for CISPR 22 Class A:
30 to 230 MHz, 40 dBµV/m at 10m measurement distance
230 to 1 GHz, 47 dBµV/m at 10 m measurement distance.
1 – 3GHz, 76dBµV/m (peak), 56dBµV/m (average) at 3m measurement distance.
3 – 5GHz, 80dBµV/m (peak), 60dBµV/m (average) at 3m measurement distance.

6.4 Environmental Conditions

6.4.1 Ambient Temperature Range

Per EN 60068-2-1 & EN / IEC 60068-2-2

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)

6.4.2 Ambient Humidity Range

Per EN /IEC 60068-2-78:

56 days at 93% relative humidity and +40 °C

Per EN / IEC 60068-2-14

5 cycles, -25°C to +55 °C
1°C / min rate of change

Per EN / IEC 60068-2-30

Damp heat cyclic, six (12 + 12) hour cycles, +25 to +55°C

6.4.3 Corrosive Environments

Per EN / IEC 60068-2-60, Part 2, Test Ke, Method (class) 3
Industrial corrosive environment/poor environmental control, mixed gas flow test.
21 days at 75% relative humidity and +30°C
Exposure to elevated concentrations of H_2S, (100 ppb), NO_2, (200 ppb) & Cl_2 (20 ppb).
Per EN / IEC 60068-2-52 Salt mist (7 days)
Per EN / IEC 60068-2-43 for H_2S (21 days), 15 ppm
Per EN / IEC 60068-2-42 for SO_2 (21 days), 25 ppm

6.5 EU Directives

6.5.1 EMC Compliance

As for 2004/108/EC:

Compliance to the European Commission Directive on EMC is demonstrated using a Technical File. Product Specific Standards were used to establish conformity:
EN 60255-26

6.5.2 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.

EN 60255-27

6.5.3 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.
Compliance demonstrated by Notified Body certificates of compliance.

6.5.4 Other Approvals

For ATEX Potentially Explosive Atmospheres directive 94/9/EC compliance, consult Schneider Electric.
For other approvals such as UL / CUL / CSA, consult Schneider Electric.

6.6 Mechanical Robustness

6.6.1 Vibration Test

Per EN / IEC 60255-21-1	Response Class 2 Endurance Class 2

6.6.2 Shock and Bump

Per EN / IEC 60255-21-2	Shock response Class 2 Shock withstand Class 1 Bump Class 1

6.6.3 Seismic Test

Per EN / IEC 60255-21-3:	Class 2

7 CORTEC

This is a generic Cortec to cover all IEDs using the **Redundant Ethernet** boards.
It does not necessarily include all the possible options for all products in the MiCOM Px4x range. Likewise, it is possible that options shown in this list, may not be available for all products

Variants / Order Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
MiCOM Protection	P														
Application/Platform:															
Feeder Management:		1	4	*											
Motor Protection:		2	4	*											
Generator Protection Relay:		3	4	*											
Distance Protection Relay:		4	4	*											
Current Differential:		5	4	*											
Transformer:		6	4	*											
Busbar:		7	4	*											
Breaker Fail:		8	4	*											
Vx Aux Rating:															
24 - 32 Vdc					9										
48 - 110 Vdc					2										
110 - 250 Vdc (100 - 240 Vac)					3										
In/Vn Rating (model dependent):															
Product Dependent						*									
Hardware Options (model dependent):															
Standard - no options							1								
IRIG-B only (modulated)							2								
Fibre optic converter only							3								
IRIG-B (modulated) & fibre optic converter							4								
Ethernet with 100Mits/s fibre-optic port							6								
Second Rear Comms Port (Courier EIA232/EIA485/k-bus)							7								
Second Rear Comms Port + IRIG-B (modulated) (Courier EIA232/EIA485/k-bus)							8								
InterMiCOM + Courier Rear Port							E								
InterMiCOM + Courier Rear Port + IRIG-B modulated							F								
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 2 LC ports + 1 RJ45 port + Modulated/Unmodulated IRIG-B							Q								
Redundant Ethernet (100Mbit/s) PRP or HSR and Dual IP, 3 RJ45 ports + Modulated/Unmodulated IRIG-B							R								
Ethernet (100Mbit/s), 1 RJ45 port + Modulated/Unmodulated IRIG-B							S								
Product Specific Options (model dependent):															
Product Dependent								*							
Protocol Options:															
K-Bus/Courier									1						
Modbus									2						
IEC60870-5-103 (VDEW)									3						
DNP3.0									4						
IEC 61850 over Ethernet and Courier via rear K-Bus/RS485 OR IEC 61850 Edition 1 and Edition 2 and Courier via rear K-Bus/RS485									6						
IEC 61850 over ethernet with CS103 rear port RS485 protocol OR IEC 61850 Edition 1 and Edition 2 and CS103 via rear port RS485									7						
IEC 61850 Edition 1 / 2 and DNPoE and DNP3 Serial with simple password management - (CSL0)									B						
IEC 61850 Edition 1 / 2 and Courier via rear K-Bus/RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) required									G						
IEC 61850 Edition 1 / 2 and CS103 via rear port RS485 with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) required									H						
IEC 61850 Edition 1 / 2 and DNPoE and DNP3 Serial with advanced Cyber Security - CSL1 - Security Administration Tool (SAT) required									L						
Mounting Options:															
Flush Panel Mounting										M					

Rack Mounting (80TE only)	N
Language Options:	
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 Version:	
	* *
Customisation:	
Default	8
Customer Specific	9
Design Suffix:	
Phase 3 CPU	L
Extended Phase 3 CPU	M

PRP NOTES

CHAPTER 20

<table>
<tr><td>Date (month/year):</td><td colspan="2">12/2016</td></tr>
<tr><td>Products covered by this chapter:</td><td colspan="2">This chapter covers the specific versions of the MiCOM products listed below. This includes only the following combinations of Software Version and Hardware Suffix.</td></tr>
<tr><td>Hardware Suffix:</td><td>P141/P142/P143 L
P145 M
P241 L
P242/P243 M
P342 L
P343/P344/P345 M
P445 L
P44x (P442/P444) M
P44y (P443/P446) M</td><td>P54x (P543/P544/P545/P546) M
P642 L
P643/P645 M
P741/P743 M
P742 L
P746 M
P841A (one circuit breaker) M
P841B (two circuit breakers) M
P849 M</td></tr>
<tr><td>Software Version:</td><td>P14x (P141/P142/P143/P145) B0/B2
P24x (P241/P242/P243) D0
P341 B1/E1
P34x (P342/P343/P344/P345) B0/B1
P445 J4/B0/B1/E0/E1
P44x (P442/P444) E0/E1
P44y (P443/P446) H4</td><td>P54x (P543/P544/P545/P546) H4
P64x (P642/P643/P645) B1/B2
P746 B1/B2/B3
C1/C2/C3
P74x (P741/P742/P743) B0
P841A G4
P841B H4
P849 B0/B1</td></tr>
<tr><td>Connection Diagrams:</td><td>P14x (P141, P142, P143 & P145):
10P141xx (xx = 01 to 02)
10P142xx (xx = 01 to 05)
10P143xx (xx = 01 to 11)
10P145xx (xx = 01 to 11)
P24x (P241, P242 & P243):
10P241xx (xx = 01 to 02)
10P242xx (xx = 01)
10P243xx (xx = 01)
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)
P44x(P442 & P444):
10P44101 (SH 1 & 2)
10P44201 (SH 1 & 2)
10P44202 (SH 1)
10P44203 (SH 1 & 2)
10P44401 (SH 1)
10P44402 (SH 1)
10P44403 (SH 1 & 2)
10P44404 (SH 1)
10P44405 (SH 1)
10P44407 (SH 1 & 2)
P44y (P443 & P446):
10P44303 (SH 01 and 03)
10P44304 (SH 01 and 03)
10P44305 (SH 01 and 03)
10P44306 (SH 01 and 03)
10P44600
10P44601 (SH 1 to 2)
10P44602 (SH 1 to 2)
10P44603 (SH 1 to 2)</td><td>P54x (P543, P544, P545 & P546):
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)
P547:
10P54702xx (xx = 01 to 02)
10P54703xx (xx = 01 to 02)
10P54704xx (xx = 01 to 02)
10P54705xx (xx = 01 to 02)
P64x (P642, P643 & P645):
10P642xx (xx = 1 to 10)
10P643xx (xx = 1 to 6)
10P645xx (xx = 1 to 9)
P74x (P741, P742 & P743):
10P740xx (xx = 01 to 07)
P746:
10P746xx (xx = 00 to 21)
P841:
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)
P849:
10P849xx (xx = 01 to 06)</td></tr>
</table>

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TABLES

FIGURES

Notes:

1 PARALLEL REDUNDANCY PROTOCOL (PRP) NOTES

1.1 Introduction to PRP

This section gives an introduction to the Parallel Redundancy Protocol (PRP); and how it is implemented on MiCOM-based products manufactured by Schneider Electric.

1.2 Protocols

Industrial real-time Ethernets typically need much better levels of availability and uninterrupted operation than normal office-type Ethernet solutions. For power networks, even a short loss of connectivity may result in a significant loss of functionality or impaired safety. To recover from a network failure, various redundancy schemes have been considered, including: Rapid Spanning Tree Protocol (RSTP), Media Redundancy Protocol (MRP) and Parallel Redundancy Protocol (PRP). The key properties of these are as follows:

RSTP this uses mesh-based topologies or ring topology and computes a tree, based on path costs and priorities. In case of network failure, a typical reset time for RSTP-based system is normally a few seconds.

MRP This uses ring-based topologies. In case of network failure, the network is broken into two separate lines, which are reconnected by de-blocking the previously blocked part. The guaranteed reset time for MRP protocol-based systems is typically around 100ms.

PRP this does not change the active topology as it uses two independent networks. Each message is replicated and sent over both networks. The first network node to receive it acts on it, with all later copies of the message being discarded. Importantly, these details are controlled by the low-level PRP layer of the network architecture, with the two networks being hidden from the higher level layers. Consequently, PRP-based networks are continuously available.

Power networks need to be able to respond to problems very quickly (typically in less than 10ms), and PRP is an available protocol which is robust enough to achieve this. The PRP protocol used in the MiCOM relay/IEDs is defined in the IEC62439-3 (2012) standard and is configured using the existing redundant Ethernet card(s).

1.3 PRP Summary (IEC 62439-3 Clause 4)

A summary of the main PRP features is given below:

- Ethernet redundancy method independent of any Ethernet protocol or topology (tree, ring or mesh)
- Seamless switchover and recovery in case of failure, which supports real-time communication
- Supervises redundancy continuously for better management of network devices
- Suitable for hot swap - 24 hour/365 day operation in substations
- Allows the mixing of devices with single and double network attached nodes on the same Local Area Network (LAN)
- Allows laptops and workstations to be connected to the network with standard Ethernet adapters (on double or single attached nodes)
- Particularly suited for substation automation, high-speed drives and transportation

1.4 Example of a PRP Network

Essentially a PRP network is a pair of similar Local Area Networks (LANs) which can be any topology (tree, ring or mesh). An example of a PRP network is shown in Figure 1:

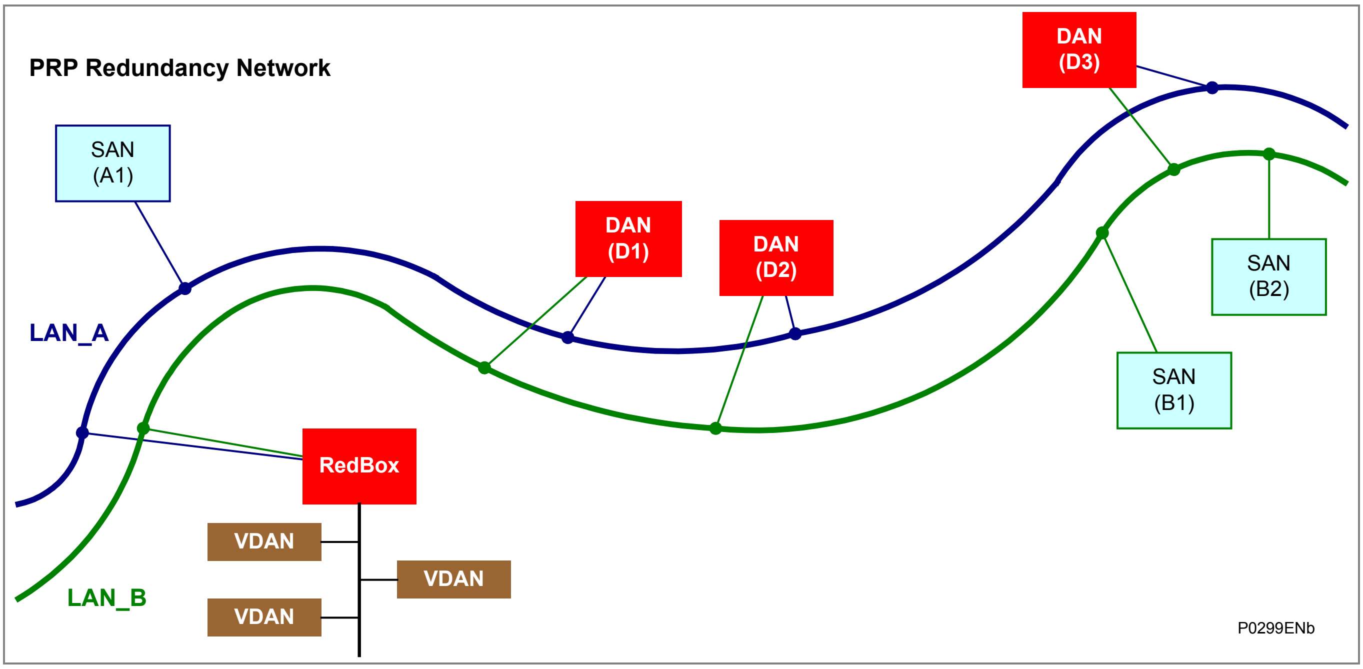

Figure 1 - PRP Redundancy Network

Figure 1 shows two similar Local Area Networks (LANs) which have various Nodes in common. The key features of these networks include:

- With the exception of a RedBox (see below), no direct cable connections can be made between the two LANs.
- Each of these LANs can have one or more Single Attached Nodes (SANs). These are normally non-critical devices that are attached only to a single network. SANs can talk to one another, but only if they are on the same LAN.
- Matched pairs of devices which are critical to the operation of the overall scheme are connected one to each network as Doubly Attached Nodes (DANs).
- To be sure that network messages (also known as frames) are transferred correctly to each DAN, each DAN must have the same Media Access Control (MAC) code and Internet Protocol (IP) address. This will also mean that TCP/IP traffic will automatically communicate with both of the paired devices, so it will be unaware of any two-layer redundancy or frame duplication issues.
- A Redundancy Box (RedBox) is used when a single interface node has to be connected to both networks. The RedBox can talk to all other nodes. So far as other nodes are concerned, the RedBox behaves like a DAN, so a SAN that is connected through a RedBox is also called a Virtual Doubly Attached Node (VDAN). The RedBox must have its own unique IP address.
- Transmission delays can be different between related Nodes of the two LANs.
- Each LAN (i.e. LAN_A and LAN_B) must be powered from a different power source and must be failure independent.

The two LANs can differ in terms of performance and topology. The redundant Ethernet interface can be made using an optical fiber connection with an LC or ST connector type or with RJ45 copper connector type. There is no need for an optical interface away from the relay.

1.5 PRP Network Structure

PRP uses two independent LANs. The topology of each of these LANs is arbitrary, and ring, star, bus and meshed topologies are possible.

The main advantage of PRP is loss-free data transmission with an active (transit) LAN. When the terminal device receives no packets from one of the LANs, the second (transit) LAN maintains the connection. As long as 1 (transit) LAN is available, repairs and maintenance on the other (transit) LAN have no impact on the data packet transmission.

The elementary devices of a PRP network are known as RedBox (Redundancy Box) and DANP (Double Attached Node implementing PRP).

Both devices have one connection each to the (transit) LANs.

The devices in the (transit) LAN are conventional switches that do not require any PRP support. The devices transmit PRP data packets transparently, without evaluating the RCT information.

Terminal devices that are connected directly to a device in the (transit) LAN are known as SAN (Single Attached Node). If there is an interruption, these terminal devices cannot be reached via the redundant line. To use the uninterruptible redundancy of the PRP network, you integrate your device into the PRP network via a RedBox.

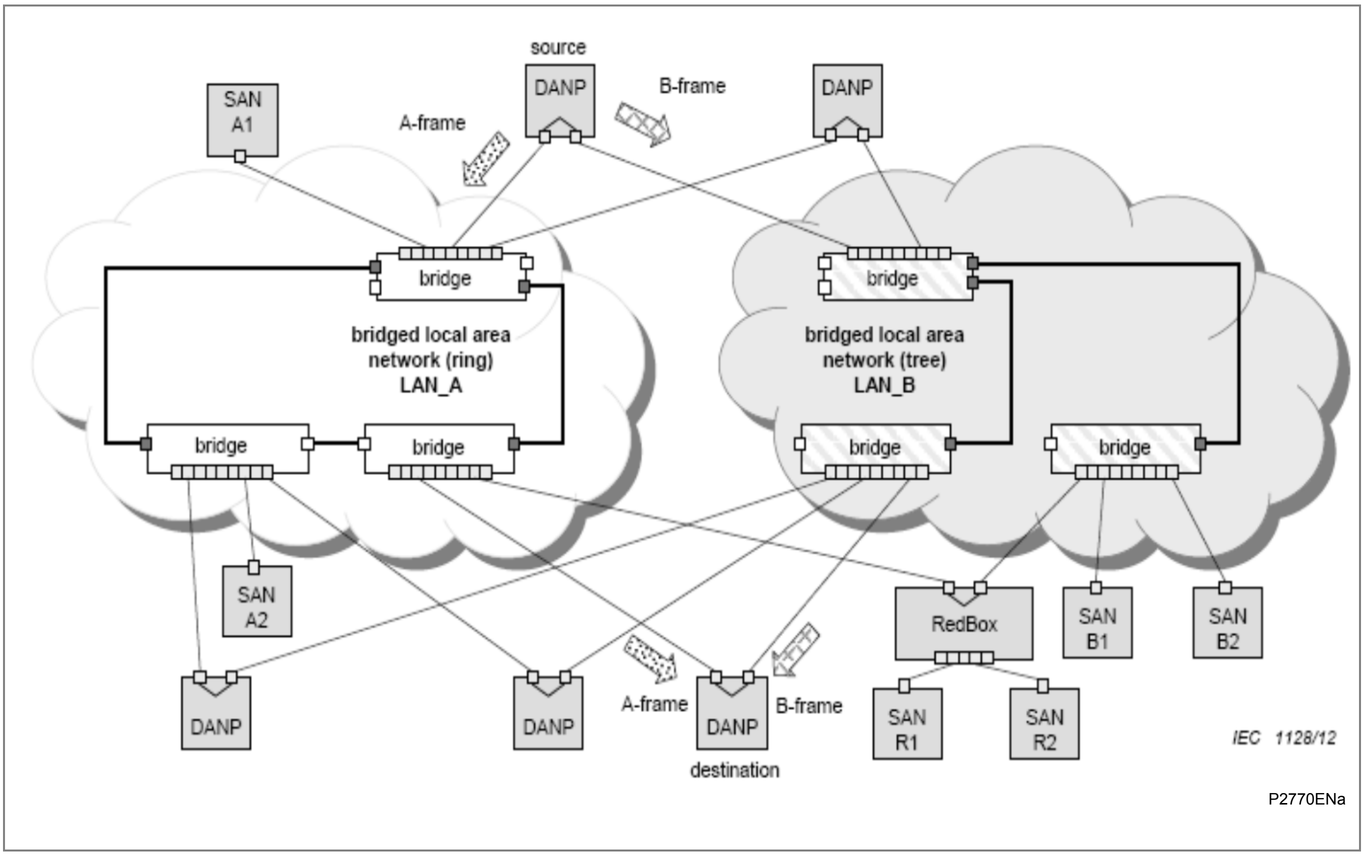

Figure 2 - PRP example of general redundant network

1.6 Structure of a DAN

A MiCOM P40 relay working in PRP Mode works as a DAN within the overall network topology. Each DAN has two ports that operate in parallel. They are attached to the upper layers of the communications stack through the Link Redundancy Entity (LRE) as in Figure 3:

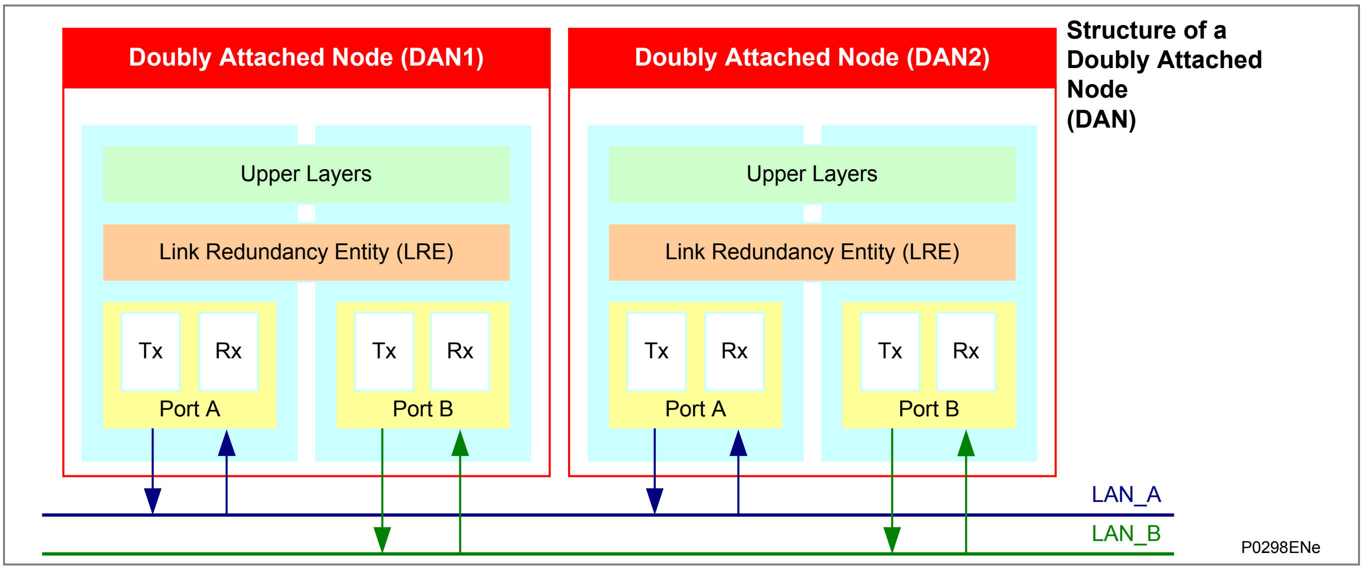

Figure 3 - Communication between two DANs (in PRP)

The LRE has two main tasks:

- handling message frames and
- management of redundancy

When an upper layer sends a frame to the LRE, the LRE replicates the frame and sends it through both its ports at nearly the same time. The two frames move through the two LANs with slightly different delays, ideally arriving at the destination node within a small time window.

When receiving frames, the LRE forwards the first frame it received to its upper layers and then discards the duplicate.

As both DAN nodes have the same MAC and IP addresses, this makes redundancy transparent to the upper layers. This allows the Address Resolution Protocol (ARP) to work in the same way as with a SAN. Accordingly, to the upper layers of a DAN, the LRE layer shows the same interface as the network adapter of a non-redundant adapter.

To manage redundancy, the LRE:

- Adds a 32-bit Redundancy Check Tag (RCT) to each frame it sends and
- Removes the RCT from each frame it receives

1.7 Communication between SANs and DANs

A SAN can be connected to any LAN and can communicate with any other SAN on the same LAN or any DAN. However, a SAN which connected to one LAN can not communicate directly to a SAN which is connected to the other LAN.

A DAN is connected to both LANs and can communicate with any RedBox or any other DANs or any SANs on either network. For communication purposes, a DAN “views” a SAN connected through a RedBox as a VDAN.

When a SAN generates a basic frame, it sends the frame only onto the LAN to which it is connected.

Originating at the SAN, a typical frame contains these parameters:

- dest_addr Destination Address
- src_addr Source Address
- type Type
- data
- fcs Frame Check Sequence (i.e. extra checksum characters added to allow error detection and correction)

The frame from the SAN is then received by the DAN; which sends the frame to its upper layers, which act accordingly.

When a DAN generates a frame, it needs to send the frame onto both of the LANs to which it is connected. When it does this, it extends the frame by adding the 48-bit Redundancy Control Trailer (RCT) into the frame.

The RCT consists of these parameters:

- 16-bit Sequence Number
- 4-bit LAN identifier, 1010 (0xA) for LAN_A and 1011 (0xB) for LAN_B
- 12-bit frame size
- PRP suffix

Note	*The Sequence number is a measure of the number of messages which have been sent since the last system reset. Each time the link layer sends a frame to a particular destination the sender increases the sequence number corresponding to that destination and sends the (nearly) identical frames over both LANs.*

Accordingly, originating at the DAN, a typical frame then contains these parameters:

- dest_addr Destination Address
- src_addr Source Address
- type Type
- lsdu Link Service Data Unit
- Padding if needed
- RCT data:
  - 16-bit sequence number:
    4-bit LAN identifier
    12-bit frame size
  - 16-bit PRP suffix (0X88 0XFB)
- fcs Frame Check Sequence

LSDU	*The Link Service Data Unit (LSDU) data allows PRP frames to be distinguished from none-PRP frames.*
Padding	*After the LSDU data, there may be some data padding. This is added to frames which would otherwise be too short for conventional network traffic (minimum frame size is 64 octets).*

Size	*The frame size will vary depending on the contents of the frame and how it has been tagged by the various SANs and DANs. In VLANs, frame tags may be added or removed during transit through a switch. To make the length field independent of tagging, only the LSDU and the RCT are considered in the size.*

Figure 4 shows the frame types with different types of data.

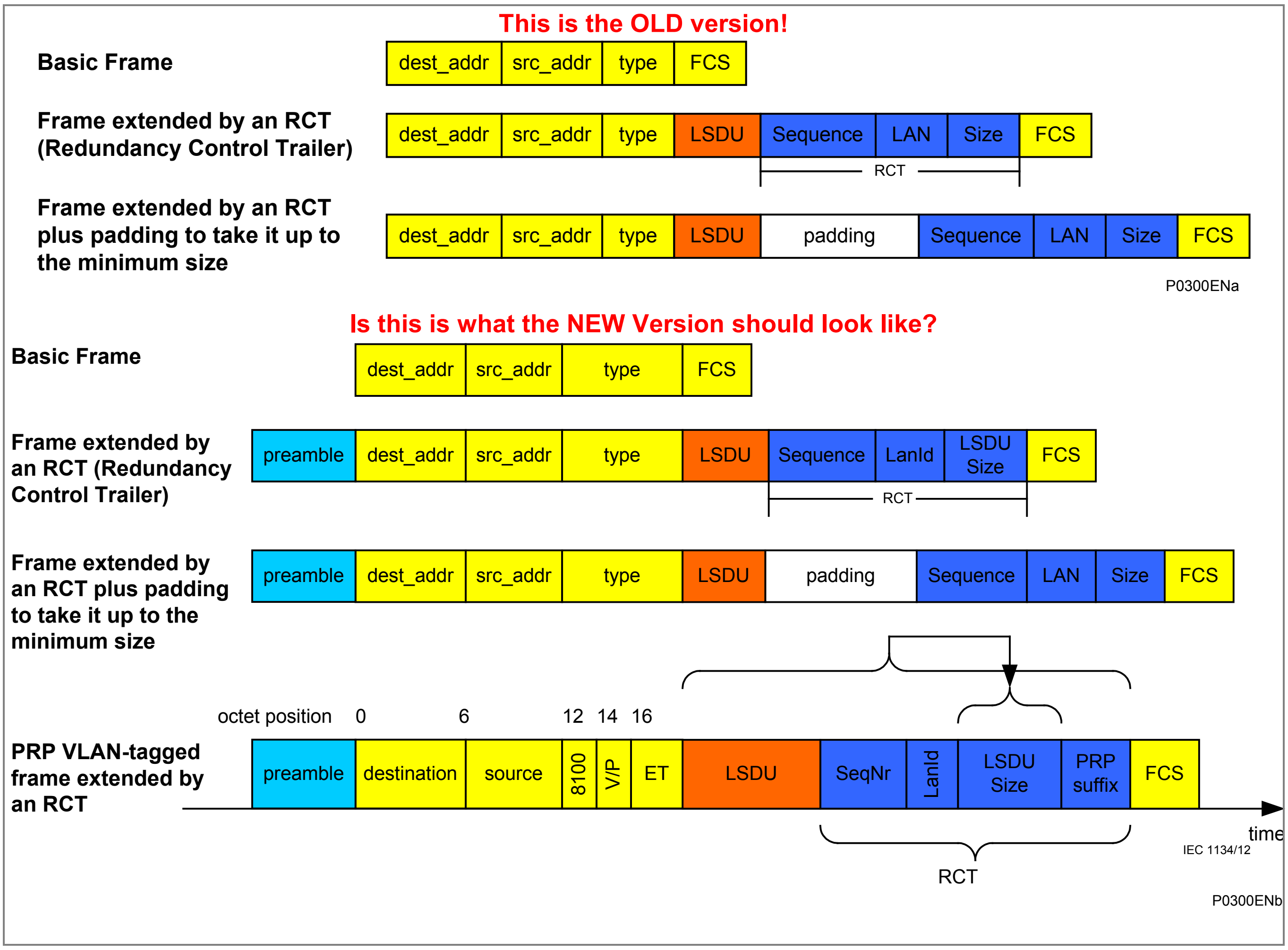

Figure 4 - Frames without and with RCT and padding

The key points about these differing frame structures is that:

- SANs do not implement any redundancy features, so they generate basic frames which SANs and DANs can understand.
- SANs can still understand the frames that come from DANs, as SANs ignore the RCT components in frames which come from DANs (a SAN cannot distinguish the RCT from the IEEE802.3 padding)
- If a DAN receives a frame which does not include the RCT component, it sends a single copy of the frame to its upper layers.
- If a DAN receives a frame which does include the RCT component, it does not send a duplicate copy of the frame to its upper layers.
- If a DANP cannot identify that the remote Node is a DAN, it inserts no RCT.

When using a Single Attached Nodes connected to the IED, a redbox is suggested to handle the case when the TPDU size for the client has been set above than 1024.

1.8 PRP Technical Data

- One VLAN tag supported.
- 128 publishers supported per receiver.
- Up to 100Mbit/s full duplex Ethernet.
- Dynamic frame memory allocation (page manager).
- Configurable duplicate detection.
- Wishbone interface for configuration and status registers.
- CPU port interface - Ethernet or Wishbone.
- Support for link-local protocols - CPU may send to specific ports only - CPU knows receive port.
- Configurable frame memory and queue length.
- Duplicate detection with configurable size and aging time.
- MAC address filtering (8 filter masks for interlink, 6 for CPU).
- Support for interfaces with or without Ethernet preamble.

Maximum Transmission Unit

According to the IEC 8802-3, the MTU (Ethernet maximum packet size) is:

- 1518 bytes without VLAN and without PRP
- 1522 bytes with VLAN and without PRP
- 1524 bytes without VLAN and with PRP
- 1528 bytes with VLAN and with PRP

Note: Check that the LAN switches setting for the MTU is at least 1528 bytes

2 PRP AND MICOM FUNCTIONS

2.1 MiCOM Products and PRP

The PRP functions being introduced as part of the overall MiCOM product range provide additional functionality, which is backwards compatible with existing Schneider Electric MiCOM equipment. This means that existing MiCOM relays/IEDS can be used on networks which use PRP functions, with no changes being made to those relays/IEDs.

The new MiCOM products that use the PRP, will interrogate other equipment to determine the equipment model number, and then use the model number to decide (at runtime), whether that particular item of equipment can support PRP or not.

MiCOM models which include the following Ethernet board assembly provide the possibility of PRP function support. This is denoted by Digit 7 where the Hardware option is N, P, Q or R, as shown in Table 1:

Hardware Option	Type	Model No format
"N" at Digit No 7	2 ST ports redundant Ethernet board (Modulated IRIG-B)	Px4xxxNx6Mxxx8K
"P" at Digit No 7	2 ST ports redundant Ethernet board (Un-modulated IRIG-B)	Px4xxxPx6Mxxx8K
"Q" at Digit No 7	2 LC + 1 RJ45 ports redundant Ethernet board (Modulated/ Un-modulated IRIG-B)	Px4xxxQx6Mxxx8M
"R" at Digit No 7	3 RJ45 ports redundant Ethernet board (Modulated/ Un-modulated IRIG-B)	Px4xxxRx6Mxxx8M

Table 1 - MiCOM model numbers for PRP options

The MiCOM relay/IED firmware has been modified to allow the PRP options to be accepted for the power-up tests in addition to the implementation of the supervision frame transmission.

2.2 MiCOM S1 Studio Software and the PRP Function

The addition of this function has no impact of the MiCOM S1 Studio support files so there is no need to upgrade any MiCOM S1 Studio software.

2.3 MiCOM Relay Configuration and the PRP Function

There is no need to change the configuration of any relay (as relays which include support for this function will be able to recognize other devices which support it).

2.4 Hardware Changes for PRP Protocol

This protocol is implemented using the existing redundant Ethernet and dual redundant Ethernet card as a starting point. The Frame management is achieved by re-programming the Field-Programmable Gate Array (FPGA).

The low-level management of the redundant frames is performed within the FPGA; this being defined as the Link Redundancy Entity (LRE). This will involve the addition of the Redundancy Check Tag (RCT) to a frame to be transmitted; this identifies the LAN and the sequence number of the message over the two networks. The FPGA is also responsible for the stripping of the RCT from received frames and discarding the duplicated messages such that only a single application frame is received by the Ethernet processor.

The LRE functionality of the supervision frame transmission is performed by the Ethernet processor card.

2.5 PRP Parameters

The Redundant Ethernet standard (IEC 62439-3:2012) defines several parameters for the PRP protocol; these being fixed at a default value within this release. The following values are set:

Parameter	Value	Description
Supervision Frame Multicast Address	01-15-4E-00-01-00	Target MAC Address for multicast supervision frame
Life Check Interval	2 seconds	Period between transmission of supervision frames
PRP Mode	Duplicate Discard	This is normal PRP mode, Duplicate address will not be supported.
Node Forget Time	60 s	This is the time after which a node entry is cleared.
Entry Forget Time	400 ms	Duration that the received message Sequence number will be held to discard a duplicate message.
Node Reboot Interval	500ms	Duration following reboot for which no PRP frames should be transmitted.

Table 2 - PRP parameter values (for PRP Protocol Version 1)

2.6 Product Implementation Features

Here is a list of the main Product Requirements for MiCOM products which support PRP:

- The MiCOM relay/IED provides two redundant Ethernet ports using PRP.
- The MiCOM relay/IED must be connected to the redundant Ethernet network as a Double Attached Node (DAN) using PRP (DAN using PRP is known as DANP)
- The redundant Ethernet interface can be made using an RJ45 or an optical fibre connection with an LC or ST connector type (Ethernet card dependent).
- The management of the PRP redundancy is transparent to the application data provided via the Ethernet interface.
- The PRP option is available with any of the existing protocol options via the Ethernet Interface (IEC61850 and/or DNPoE)
- Loss of one of the LAN connections to the device does not cause any loss or degradation to the Application data over the Ethernet interface.
- The MiCOM relay/IED supports the transmission of the PRP Supervision frame at a fixed time period (LifeCheckInterval) of 2s (+/- 100ms)
- Each supervision frame includes a sequence number as defined in the IEC 62439-3:2012 specification. This is incremented for each supervision message and the value starts from zero following a system restart.
- The MiCOM relay/IED does not process received supervision frames to provide supervision of the redundant network.
- The MiCOM relay/IED does not provide for the PRP management to be configured (via either the MiCOM relay/IED HMI or the Ethernet interface). Accordingly, the default values (as defined within this document) are used for all PRP parameters.
- The performance of the Ethernet Interface is not degraded by using the PRP interface.

2.6.1 Abbreviations and Acronyms

Abbreviations / Acronyms	Meaning
CRC	Cyclic Redundancy Check
DAN	Doubly Attached Nodes
DANP	Doubly Attached Node implementing PRP
FPGA	Field-Programmable Gate Array
HMI	Human Machine Interface
IED	Intelligent Electronic Devices
IP	Internet Protocol
LAN	Local Area Network
LRE	Link Redundancy Entity
MAC	Media Access Control
MRP	Media Redundancy Protocol
PRP	Parallel Redundancy Protocol
RCT	Redundancy Check Tag
RedBox	Redundancy Box
RSTP	Rapid Spanning Tree Protocol
SAN	Singly Attached Node
TCP	Transmission Control Protocol
VDAN	Virtual Doubly Attached Node

Notes:

HSR NOTES

CHAPTER 21

Date (month/year):	11/2016			
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:	P141/P142/P143	L	P54x (P543/P544/P545/P546)	M
	P145	M	P642	L
	P241	L	P643/P645	M
	P242/P243	M	P741/P743	M
	P342	L	P742	L
	P343/P344/P345	M	P746	M
	P391	A	P74x (P741, P743)	K
	P445	L	P841A (one circuit breaker)	M
	P44x (P441/P442/P444)	K	P841B (two circuit breakers)	M
	P44x (P442/P444)	M	P849	M
	P44y (P443/P446)	M		
Software Version:	P14x (P141/P142/P143/P145)	B0/B2	P54x (P543/P544/P545/P546)	H4
	P24x (P241/P242/P243)	D0	P64x (P642/P643/P645)	B2
	P34x (P342/P343/P344/P345/P391)	B0	P746	B3/C3
	P445	J4	P74x (P741/P742/P743)	B0
	P44x (P442/P444)	E0/E1	P841A	G4
	P44y (P443/P446)	H4	P841B	H4
			P849	B0/B1
Connection Diagrams:	P14x (P141, P142, P143 & P145): 10P141xx (xx = 01 to 02) 10P142xx (xx = 01 to 05) 10P143xx (xx = 01 to 11) 10P145xx (xx = 01 to 11) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 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) P44x(P442 & P444): 10P44101 (SH 1 & 2) 10P44201 (SH 1 & 2) 10P44202 (SH 1) 10P44203 (SH 1 & 2) 10P44401 (SH 1) 10P44402 (SH 1) 10P44403 (SH 1 & 2) 10P44404 (SH 1) 10P44405 (SH 1) 10P44407 (SH 1 & 2) P44y (P443 & P446): 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2)		P54x (P543, P544, P545 & P546): 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) P547: 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) P74x (P741, P742 & P743): 10P740xx (xx = 01 to 07) P746: 10P746xx (xx = 00 to 21) P841: 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) P849: 10P849xx (xx = 01 to 06)	

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1 INTRODUCTION TO HSR

1.1 Introduction to High-availability Seamless Redundancy (HSR)

This section gives an introduction to the High-availability Seamless Redundancy (HSR); and how it is implemented on MiCOM-based products manufactured by Schneider Electric.

1.2 Protocols

Industrial real-time Ethernets typically need much better levels of availability and uninterrupted operation than normal office-type Ethernet solutions. For power networks, even a short loss of connectivity may result in a significant loss of functionality or impaired safety. To recover from a network failure, various redundancy schemes have been considered, including: Rapid Spanning Tree Protocol (RSTP), Media Redundancy Protocol (MRP), High-availability Seamless Redundancy (HSR). The key properties of these are as follows:

RSTP This uses mesh-based topologies or ring topology and computes a tree, based on path costs and priorities. In case of network failure, a typical reset time for RSTP-based system is normally a few seconds.

MRP This uses ring-based topologies. In case of network failure, the network is broken into two separate lines, which are reconnected by de-blocking the previously blocked part. The guaranteed reset time for MRP protocol-based systems is typically around 100ms.

HSR HSR basically uses ring topology, This Clause describes the application of the HSR principles (Clause 5) to implement a High-availability Seamless Redundancy (HSR), retaining the PRP property of zero recovery time, applicable to any topology, in particular rings and rings of rings. With respect to PRP, HSR allows to roughly halve the network infrastructure. With respect to rings based on IEEE 802.1D (RSTP), IEC 62439-2 (MRP), IEC 62439-6 (DRP) or IEC 62439-7 (RRP), the available network bandwidth for network traffic is somewhat reduced depending on the type of traffic. Nodes within the ring are restricted to be HSR-capable bridging nodes, thus avoiding the use of dedicated bridges. Singly Attached Nodes (SANs) such as laptops or printers cannot be attached directly to the ring, but need attachment through a RedBox (redundancy box).

Power networks need to be able to respond to problems very quickly (typically in less than 10ms), and HSR is an available protocol which is robust enough to achieve this. The HSR protocol used in the MiCOM relay/IED is defined in the IEC62439-3 (2012) standard and is configured using the existing redundant Ethernet card(s).

1.3 HSR Summary (IEC 62439-3 Clause 5)

A summary of the main HSR features is given below:

- HSR Ethernet redundancy method independent of any industrial Ethernet protocol and typically used in a ring topology
- Seamless switchover and recovery in case of failure, which supports real-time communication
- Supervises redundancy continuously for better management of network devices
- Suitable for hot swap, 24 hour/365 day operation in substations
- Allows laptops and workstations to be connected to the network with HSR Redbox
- Particularly suited for substation automation, high-speed drives and transportation

1.4 Example of an HSR Network

Essentially a HSR network is a ring topology. An example of a HSR network is shown in Figure 1:

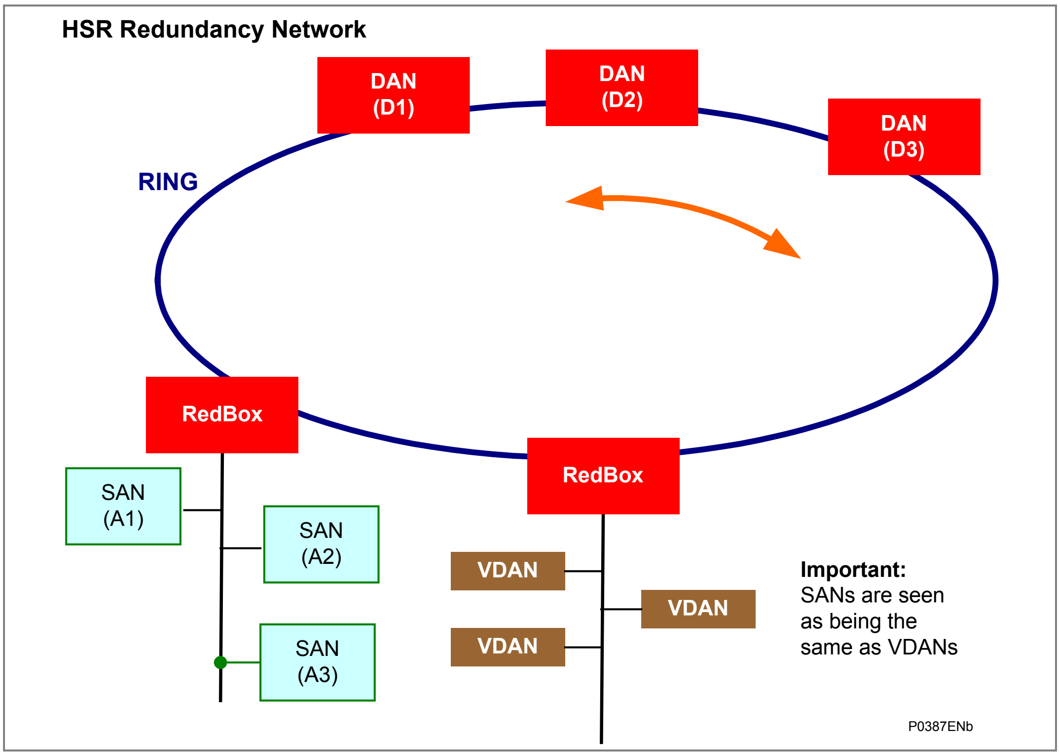


Figure 1 - HSR Redundancy Network

Figure 1 shows typical ring networks that have various Nodes in common.

The key features of the network include:

- Nodes within the ring are restricted to be HSR-capable bridging nodes, thus avoiding the use of dedicated bridges
- Singly Attached Nodes (SANs) such as laptops or printers cannot be attached directly to the ring, but need attachment through a RedBox (redundancy box)
- A simple HSR network consists of doubly attached bridging nodes, each having two ports, interconnected by full-duplex link
- A source DANH sends a frame passed from its upper layers, prefixes it by an HSR tag to identify frame duplicates and sends the frame over each port
- A destination DANH receives, in the fault-free state, two identical frames from each port within a certain interval, if it is a multicast frame, it instantaneously forwards it on the ring (see Note *), removes the HSR tag of the first frame before passing it to its upper layers and discards any duplicate.

*Note **	*In particular, the node will not forward a frame that it injected into the ring.*
*Note **	*A destination node of a unicast frame does not forward a frame for which it is the only destination, except for testing.*

1.5 Structure of a DAN

A MiCOM P40 relay working in HSR Mode works as a DAN within the overall network topology. Each DAN has two ports that operate in parallel. As in Figure 2, The two HSR ports A and B and the device port C are connected by the LRE, which includes a switching matrix allowing to forward frames from one port to the other. The switching matrix allows cut-through bridging. The Link Redundancy Entity (LRE) presents to the higher layers the same interface as a standard Ethernet transceiver would do.

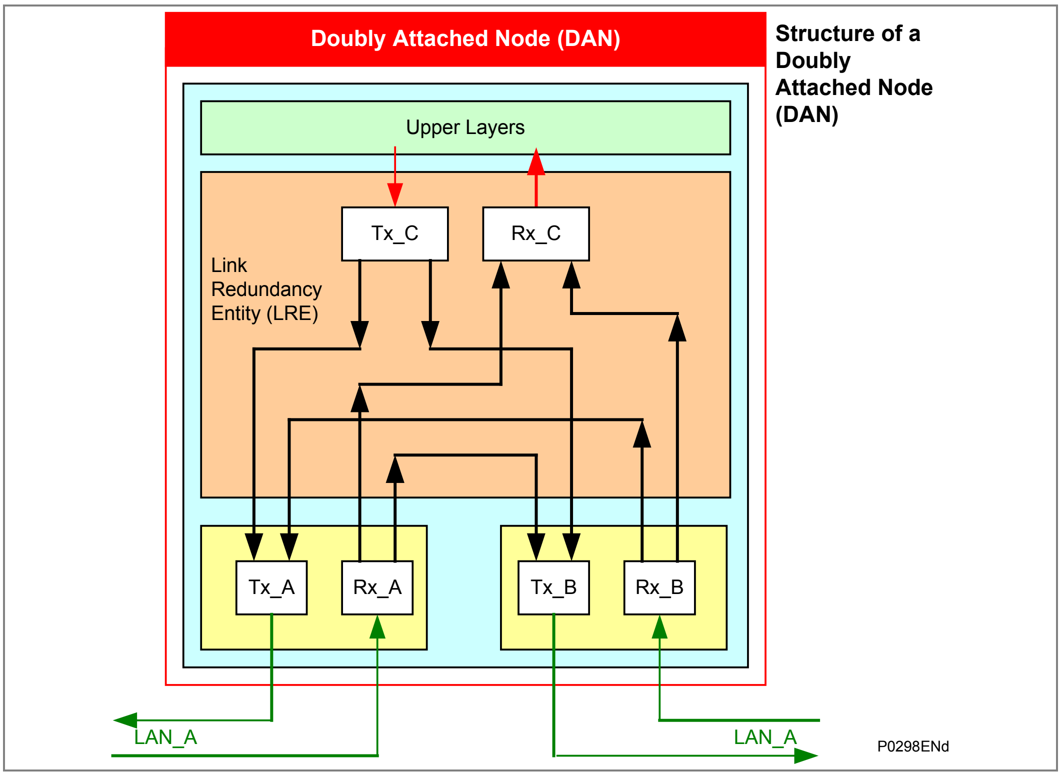


Figure 2 - DAN communication between two paths (in HSR)

DAN node is operable in HSR-tagged forwarding mode, the DAN inserts the HSR tag on behalf of its host and forwards the ring traffic, except for frames sent by the node itself. Duplicate frames and frames where the node is the unicast destination is not forwarded.

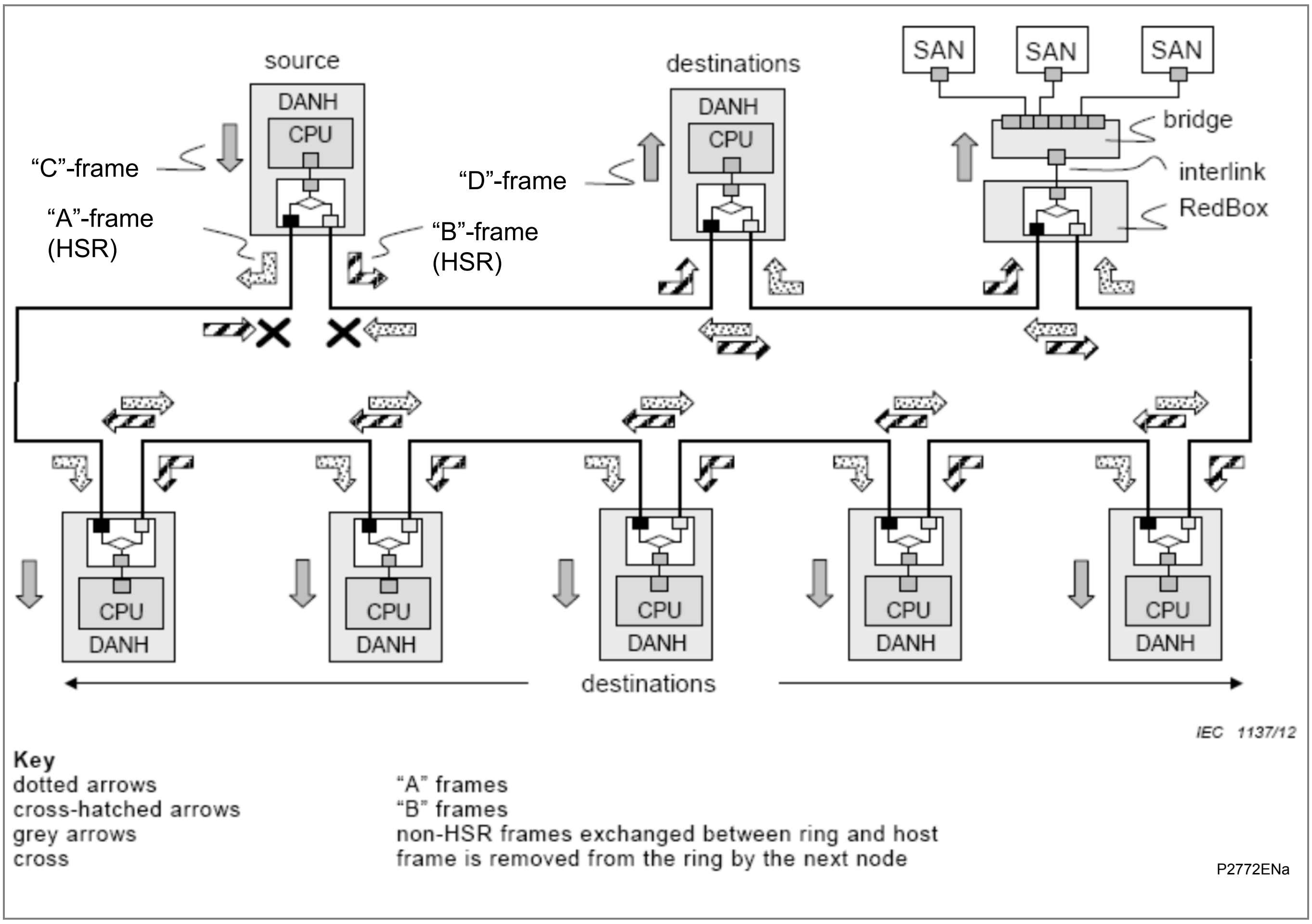


Figure 3 - HSR example of ring configuration for multicast traffic

1.6 Structure of a RedBox

The RedBox has a LRE that performs the duties of the HSR protocol, in particular:

- forwards the frames received from one HSR port to the other HSR port, unless the frame receives frames addressed to its own upper protocols
- prefixes the frames sent by its own upper layers with the corresponding HSR tag before sending two copies over its HSR ports

The switching logic is incorporated into the RedBox, so interlink becomes an internal connection.

A simple RedBox is present in every node, since the LRE makes a transition to a single non-HSR host. In addition, it is usual to have more than one host in a node, since a port for maintenance often exists.

A node does not send over a port a frame that is a duplicate of a frame previously sent over that port in that same direction.

For the purpose of Duplicate Discard, a frame is identified by:

- its source MAC address;
- its sequence number.

The Duplicate Discard method forgets an entry identified by <Source MAC Address><Sequence number> after a time EntryForgetTime.

1.7 Communication between SANs, DANs and RedBoxs

Singly Attached Nodes (SANs), for instance maintenance laptops or printers cannot be inserted directly into the ring since they have only one port and cannot interpret the HSR tag in the frames. SANs communicate with ring devices through a RedBox (Redundancy Box) that acts as a proxy for the SANs attached to it.

A source DANH sends a frame passed from its upper layers, and prefixes it by an HSR tag to identify frame duplicates and sends the frame over both ports.

A destination DANH receives, in the fault-free state, two identical frames from each port within a certain interval, if it is a multicast frame, it instantaneously forwards it on the ring, removes the HSR tag of the first frame before passing it to its upper layers and discards any duplicate.

A typical frame contains these parameters:

- dest_addr Destination Address
- src_addr Source Address
- type Type
- data
- fcs Frame Check Sequence (i.e. extra checksum characters added to allow error detection and correction)

HSR frames are identified uniquely by their HSR tag.

The HSR tag consists of these parameters:

- 16-bit Ethertype (HSR_EtherType = 0x892F)
- 4-bit path identifier (PathId), 0000 for both HSR nodes A and B, and 0010-1111 for one of 7 PRP networks (A/B).
- 12-bit frame size (LSDUsize)
- 16-bit Sequence Number (SeqNr)

Note	*The 4-bit PathId field prevents reinjection of frames coming from one PRP network to another PRP network.*

Accordingly, a typical HSR frame then contains these parameters:

- dest_addr Destination Address
- src_addr Source Address
- HSR tag data:
  - 16-bit Ethertype (HSR_EtherType = 0x892F)
  - 4-bit path identifier
  - 12-bit frame size
  - 16-bit sequence number:
- type Type
- payload Payload
- Padding if needed
- fcs Frame Check Sequence

Padding	*After the payload data, there may be some data padding. This is added to frames which would otherwise be too short for conventional network traffic (minimum frame size is 70 octets).*
Size	*The frame size will vary depending on the contents of the frame and how it has been tagged by the various SANs and DANs. In VLANs, frame tags may be added or removed during transit through a switch. To make the length field independent of tagging, only the original LPDU and the HSR tag are considered in the size.*

Figure 4 and Figure 5 shows the frame types with different types of data.

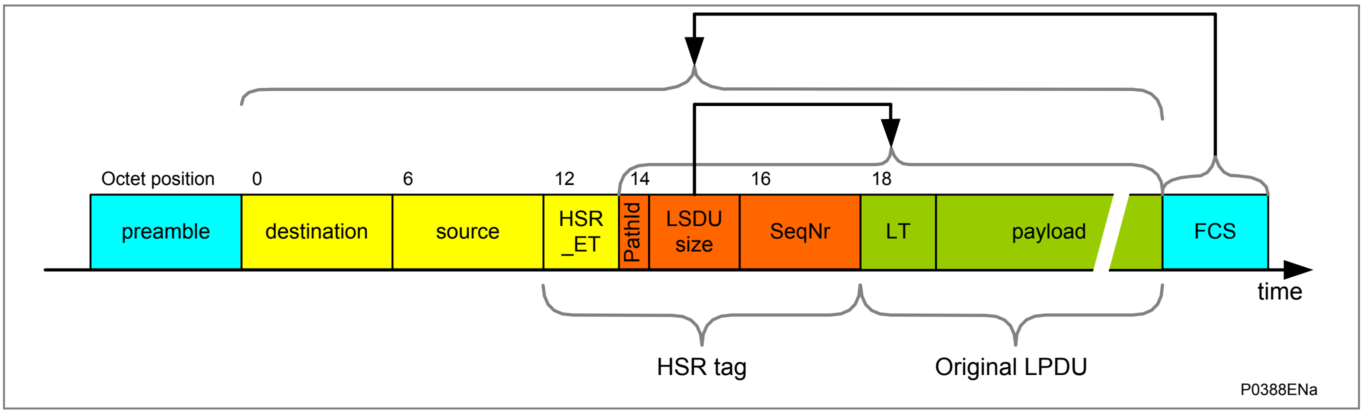


Figure 4 - HSR frame without a VLAN tag

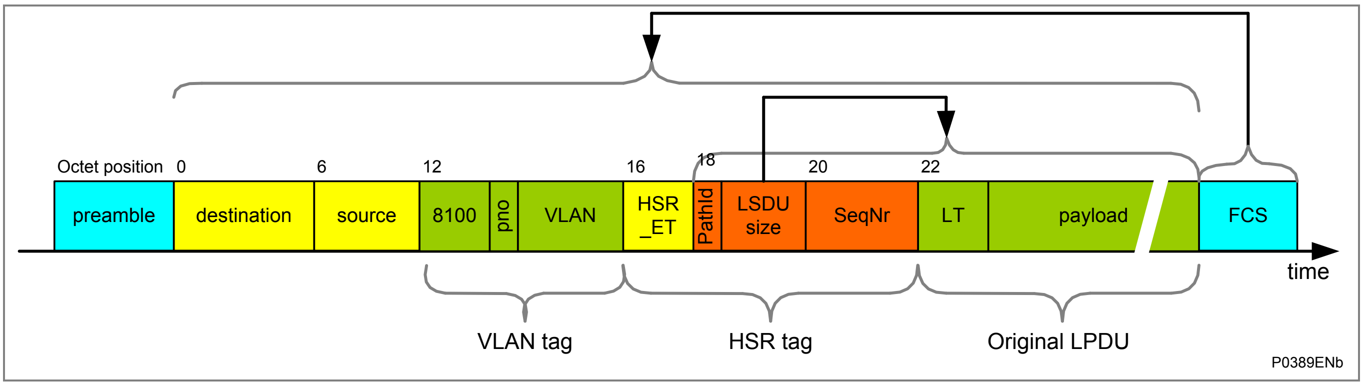


Figure 5 - HSR frame with VLAN tag

The key points about these differing frame structures are that:

- Unlike PRP, SANs cannot be attached directly to such a duplicated network unless they are able to interpret the HSR tag.
- In particular, the node will not forward a frame that it injected into the ring.
- A destination node of a unicast frame does not forward a frame for which it is the only destination, except for testing.
- DANH receiving from an HSR port, if this frame is not HSR-tagged and is a link local traffic, consume the frame and do not forward it.
- DANH receiving from an HSR port, if this frame is HSR-tagged and this node is not a destination, do not pass the frame to the link layer interface.
- A node accepts an HSR tagged frame also if the LanId does not correspond to the PortId and if the LSDUsize does not match the frame size.

1.8 HSR Technical Data

- One VLAN tag supported
- Up to 128 devices supported
- Up to 100Mbit/s full duplex Ethernet
- Dynamic frame memory allocation (page manager)
- Configurable duplicate detection
- Wishbone interface for configuration and status registers
- CPU port interface - Wishbone
- Support for link-local protocols - CPU may send to specific ports only - CPU knows receive port
- Configurable frame memory and queue length
- Duplicate detection with configurable size and aging time

- MAC address filtering (8 filter masks for interlink port, 6 for CPU port)
- Support for interfaces with or without Ethernet preamble

Limitations:

Number of IEDs on a same ring at 100Mbit/s:

Each hop (IED or RedBox) not only carries its own messages but also all the other IED messages thus the bandwidth used is proportional to the number of IEDs.

The maximum number of hops is around 20 when the GOOSE messages are highly used or 40 if the number and importance of GOOSE messages is not high.

When Precision Time Protocol («IEEE1588/IEC 61588») is used:

As the GPS receiver inaccuracy is 200ns and as each hop (IED or RedBox) can add a 50ns inaccuracy, the maximum number of hops is 16 if 1µs accuracy is required (PMU application or Process Bus)

2 HSR AND MICOM FUNCTIONS

2.1 MiCOM Products and HSR

The HSR functions being introduced as part of the overall MiCOM product range provide additional functionality, which is backwards compatible with existing Schneider Electric MiCOM equipment. This means that existing MiCOM relays/IEDS can be used on networks, which use HSR functions, with no changes being made to those relays/IEDs.

The new MiCOM products that use the HSR, will interrogate other equipment to determine the equipment model number, and then use the model number to decide (at runtime), whether that particular item of equipment can support HSR or not.

MiCOM models which include the following Ethernet board assembly provide the possibility of HSR function support. This is denoted by Digit 7 where the Hardware option is Q or R, as shown below:

Hardware Option	Type	Model No format
“Q” at Digit No 7	2 LC + 1 RJ45 ports redundant Ethernet board (Modulated/ Un-modulated IRIG-B)	Px4xxxQx6Mxxx8M
“R” at Digit No 7	3 RJ45 ports redundant Ethernet board (Modulated/ Un-modulated IRIG-B)	Px4xxxRx6Mxxx8M

Table 1 - Hardware option numbers with HSR functions

The MiCOM relay/IED firmware has been modified to allow the HSR options to be accepted for the power-up tests in addition to the implementation of the supervision frame transmission.

2.2 MiCOM S1 Studio Software and the HSR Function

The addition of this function has no impact of the MiCOM S1 Studio support files so there is no need to upgrade any MiCOM S1 Studio software.

2.3 MiCOM Relay Configuration and the HSR Function

There is no need to change the configuration of any relay (as relays which include support for this function will be able to recognize other devices which support it).

2.4 Hardware Changes for HSR Protocol

This protocol is implemented using the redundant Ethernet card as a starting point. The Frame management is achieved by programming the Field-Programmable Gate Array (FPGA).
The low-level management of the redundant frames is performed within the FPGA; this being defined as the Link Redundancy Entity (LRE). This will add the HSR tag to a frame to be transmitted. The FPGA is also responsible for the stripping of the HSR tag from received frames and discarding the duplicated messages so that only a single application frame is received by the Ethernet processor.
The LRE functionality of the supervision frame transmission is performed by the NIOS II.

The new version of the redundant Ethernet card is based on the 2072069A01 and 2072071A01 (both have modulated and un-modulated IRIG-B).

2.5 HSR Parameters

The Redundant Ethernet standard (IEC 62439-3:2012/FDIS) defines several parameters for the HSR protocol; these being fixed at a default value within this release. The following values are set:

Parameter	Value	Description
Supervision Frame Multicast Address	01-15-4E-00-01-00	Target MAC Address for multicast supervision frame
Life Check Interval	2 seconds	Period between transmission of supervision frames
HSR Mode	Duplicate Discard	This is normal HSR mode, Duplicate address will not be supported.
Node Forget Time	60 s	This is the time after which a node entry is cleared.
Entry Forget Time	400 ms	Duration that the received message Sequence number will be held to discard a duplicate message.
Node Reboot Interval	500ms	Duration following reboot for which no HSR frames should be transmitted.
MulticastFilterSize	16	Number of multicast addresses to be filtered

Table 2 - HSR parameter values

2.6 Product Implementation Features

Here is a list of the main Product Requirements for MiCOM products that support HSR:

- The MiCOM relay/IED provides two redundant Ethernet ports using HSR.
- The MiCOM relay/IED must be connected to the redundant Ethernet network as a Double Attached Node (DAN) using HSR (DAN using HSR is known as DANH)
- The redundant Ethernet interface can be made using an RJ45 or an optical fibre connection with an LC connector type.
- The management of the HSR redundancy is transparent to the application data provided via the Ethernet interface.
- The HSR option is available with any of the existing protocol options via the Ethernet Interface (IEC61850 and/or DNPoE)
- Loss of one of the Node connections to the device does not cause any loss or degradation to the Application data over the Ethernet interface.
- The MiCOM relay/IED supports the transmission of the HSR Supervision frame at a fixed time period (LifeCheckInterval) of 2s (+/- 100ms)
- Each supervision frame includes a sequence number as defined in the IEC 62439-3:2012/FDIS specification. This will be incremented for each supervision message and the value will start from zero following a system restart.
- The MiCOM relay/IED support SNMP.
- The MiCOM relay/IED does not provide for the HSR management to be configured (via either the MiCOM relay/IED HMI or the Ethernet interface). Accordingly, the default values (as defined within this document) are used for all HSR parameters.
- The performance of the Ethernet Interface is not degraded by using the HSR interface.

2.6.1 Abbreviations and Acronyms

Abbreviations / Acronyms	Meaning
CRC	Cyclic Redundancy Check
DAN	Doubly Attached Nodes
DANH	Doubly Attached Node implementing HSR
FPGA	Field-Programmable Gate Array
HMI	Human Machine Interface
HSR	High-availability Seamless Redundancy
IED	Intelligent Electronic Devices
IP	Internet Protocol
LAN	Local Area Network
LRE	Link Redundancy Entity
MAC	Media Access Control
MRP	Media Redundancy Protocol
PRP	Parallel Redundancy Protocol
HSR	High-availability Seamless Redundancy
RedBox	Redundancy Box
RSTP	Rapid Spanning Tree Protocol
SAN	Singly Attached Node
TCP	Transmission Control Protocol
VDAN	Virtual Doubly Attached Node (effectively seen as a DAN)

Notes:

FIRMWARE AND MANUAL VERSION HISTORY

CHAPTER 22

Date:	06/2017
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 (P342) M (P343/P344/P345) A (P391)
Software Version:	B2
Connection Diagrams:	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)

CONTENTS

Notes:

1 SOFTWARE AND HARDWARE VERSION HISTORY

The Easergy Studio (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 Easergy Studio (MiCOM S1 Studio).**

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
01	A	A	Oct 1999	Original Issue.	V1.09 or Later	TG8614A
01	B	A	Dec 1999	Corrected 90 degree phase angle displacement in measurement of Ia, Ib, Ic. Corrected RTD temperature and invalid system frequency measurements in MODBUS fault records. Corrected VT scaling factors for Va, Vb, Vc in fault records.	V1.09 or Later	TG8614A
01	C	A	Mar 2000	Trip LED status saved during power cycling. Corrections to omission of fault duration and CB operating time in fault record. Corrected -90 degree phase angle displacement in measurement of VN and VN derived. Reset of alarms and indications event added to event record.	V1.09 or Later	TG8614A
02	A	A	Oct 2000	DNP 3. 0 protocol added. Courier and MODBUS enhancements to improve compatibility with other protection (mainly PX20 products). Modifications to IEC60870-5-103 Test Mode. Poledead logic DDB signals made visible in PSL. Foreign Language text updated. Active and reactive power added to MODBUS fault record.	V1.10 or Later	TG8614B
03	A	A	Jan 2001	Event filtering added. Correction to energy measurement inaccuracy.	V2.00 or Later	TG8614B
03	B	A	May 2001	Correction to NPS Alarm operation.	V2.00 or Later	TG8614B
03	C	A	Jan 2002	Resolved possible reboot caused by Disturbance Recorder.	V2.00 or Later	TG8614B
03	D	A	Feb 2002	Resolved possible reboot caused by invalid MODBUS requests.	V2.00 or Later	TG8614B
03	E	A	Dec 2002	DNP 3. 0 Object 12 “CROB” implementation is now compliant for simple function points. DNP 3. 0 Object 10 included in Class 0 poll. DNP 3. 0 support for season in time information. Correction to MODBUS CB Trip and Close via "0" command. Change to neutral voltage displacement protection and directional SEF protection so that they are not blocked by the VT supervision logic when the VN Input and ISEF>VNPol are selected as Measured. Correction to undervoltage stage 2 (V<2) setting range. The setting range has been increased from 10-70V to 10-120V (Vn=110/120V) so that it is the same as V<1. Correction to VT ratio scaling problem in the disturbance recorder. Improvement to the RTD start-up calibration routine.	V2.00 or Later	TG8614B

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
03	F	A	Mar 2004	Improvement to the differential protection performance at low frequencies. Correction to the fault recorder window for current based trips so that it can terminate properly once the FAULT_REC_TRIG signal (DDB 288) is reset. Previously it needed to wait for Relay 3 to reset also before termination. Power measurement limits added to prevent non zero values with no current and voltage. Also power factor measurements limited to +/-1. Resolved possible reboot caused by failure to time sync. from DNP 3. 0 when IRIG-B is active which is also providing the time sync. Now, any failure of the DNP 3. 0 to time sync. will only produce a maintenance record. Correction to French, German and Spanish language menu text for generator differential IS2 setting [3004] which incorrectly refers to the setting as IS1. Resolved possible problem with disturbance recorder triggering which could cause loss of disturbance record data, temporary freezing of the user interface or loss of rear port communications. Resolved unreliable MODBUS framing. Resolved creation of spurious password expired event when menu cell or MODBUS register is accessed. Resolved error code 0x 8D840000.	V2.00 or Later	TG8614B
03	G	A	Jun 2004	For Courier/DNP 3. 0/IEC60870-5-103 builds only. Correction to parity setting for MODBUS and DNP 3. 0 when the relay is powered up. Improvement to the self checking of the analog channels and SRAM.	V2.00 or later	TG8614B
03	H	A	Jul 2004	For MODBUS builds only. Changes as for G. Improvement to the MODBUS driver to cope better with spurious data transmissions and failures of the relay to respond to commands where the server response time is fast.	V2.00 or later	TG8614B
03	J	A	Jun 2005	Correction to the alarm and trip indication of the faulted phase(s) for the second stage of the undervoltage and overvoltage protection in the fault record information on the relay LCD . Correction to false frequency protection start at power-up. MODBUS driver modified to prevent relay reboot with error code 0x8C810000 in hardware A/B/C relays for 60Hz applications where fast polling and high baud rates are used. Modification to prevent reboot when large number of control and settings are sent to relay in quick succession over DNP 3. 0.	V2.00 or later	TG8614B
04	A	A	Jun 2001	Not released to production. Pole slipping and sensitive reverse power added. 100% stator earth fault protection enhancements. W/VAr/VA inhibit elements added to 3rd harmonic undervoltage protection and 3rd harmonic overvoltage protection added. Neutral voltage displacement threshold, VN>1/2, increased from 50 to 80 V (Vn=100/120 V), 200 to 320 V (Vn=380/480 V). Earth fault polarizing voltage threshold, Vnpol, increased from 22 to 88 V (Vn=100/120 V) and 88 to 352 V (Vn=380/480 V). Cos phi and sin phi features added to SEF protection.	V2.01 or later	TG8614B
04	B	A	Jul 2001	Not released to production. Minor bug fix to background self-check diagnostics introduced in 04A	V2.01 or later	TG8614B
04	C	A	Dec 2001	Correction to Courier NPS thermal reset command.	V2.01 or later	TG8614B
04	D	A	Jan 2002	Resolved possible reboot caused by Disturbance Recorder.	V2.01 or later	TG8614B
04	E	A	Feb 2002	Resolved possible reboot caused by invalid MODBUS requests.	V2.01 or later	TG8614B

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
04	F	A	Dec 2002	Enhanced DNP 3. 0 Object 10 support for Pulse On/Close control points. DNP 3. 0 Object 10 included in Class 0 poll. DNP 3. 0 support for season in time information. Correction to MODBUS CB Trip and Close via "0" command. Change to neutral voltage displacement protection and directional SEF protection so that they are not blocked by the VT supervision logic when the VN Input and ISEF>VNPol are selected as Measured. Correction to undervoltage stage 2 (V<2) setting range. The setting range has been increased from 10-70 V to 10-120 V (Vn=110/120 V) so that it is the same as V<1. Correction to VT ratio scaling problem in the disturbance recorder. Improvement to the RTD start-up calibration routine.	V2.01 or later	TG8614B
04	G	A	Mar 2004	Improvement to the differential protection performance at low frequencies. Correction to the fault recorder window for current based trips so that it can terminate properly once the FAULT_REC_TRIG signal (DDB 288) is reset. Previously it needed to wait for Relay 3 to reset also before termination. Power measurement limits added to prevent non zero values with no current and voltage. Also power factor measurements limited to +/-1.	V2.01 or later	TG8614B
04	G	A	Mar 2004	Resolved possible reboot caused by failure to time sync. from DNP 3. 0 when IRIG-B is active which is also providing the time sync. Now, any failure of the DNP 3. 0 to time sync. will only produce a maintenance record. Correction to French, German and Spanish language menu text for generator differential IS2 setting [3004] which incorrectly refers to the setting as IS1. Resolved possible problem with disturbance recorder triggering which could cause loss of disturbance record data, temporary freezing of the user interface or loss of rear port communications. Resolved unreliable MODBUS framing. Resolved creation of spurious password expired event when menu cell or MODBUS register is accessed. Resolved error code 0x 8D840000.	V2.01 or later	TG8614B
04	(1)G	A	Mar 2004	Changes are the same as 04G. Special for Powerformer stuck pole breaker fail application where the neutral voltage displacement setting range has been increased from 80 to 200 V (Vn-100/120 V). MODBUS build only.	V2.01 or later	TG8614B
04	H	A	Jun 2004	For Courier/DNP 3. 0/IEC60870-5-103 builds only. Correction to parity setting for MODBUS and DNP 3. 0 when the relay is powered up. Improvement to the self checking of the analog channels and SRAM.	V2.01 or later	TG8614B
04	J	A	Jul 2004	For MODBUS builds only. Changes as for H. Improvement to the MODBUS driver to cope better with spurious data transmissions and failures of the relay to respond to commands where the server response time is fast.	V2.01 or later	TG8614B
04	K	A	Jun 2005	Changes are the same as 03J.	V2.01 or later	TG8614B

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
05	A	A/B	Sep 2001	Not released to production. Thermal overload protection added. Additional stage of under-impedance protection. Control inputs added. PSL DDB list of signals increased from 512 to 1023 signals. PSL Data menu added with PSL Reference information for version history. Optional additional opto inputs and output contacts with a larger case size option available. New 'Universal' wide ranging opto inputs (Model number hardware suffix changed to B). New output contacts with better break and continuous carry ratings (Model number hardware suffix changed to B). Courier and MODBUS builds only.	V2.05 or Later	P34x/EN T/C11
05	B	A/B	Oct 2001	Not released to production. Correction to VT ratio scaling problem in the disturbance recorder. Courier and MODBUS builds only.	V2.05 or Later	P34x/EN T/C11
05	1(C)	A/B	Aug 2000	IEC60870-5-103 build with special private code mapping for ALSTOM Power project in Iceland. Includes private codes and uncompressed disturbance recorder. Resolved possible reboot caused by Disturbance Recorder. IEC60870-5-103 build only.	V2.05 or Later	P34x/EN T/C11
05	D	A/B	Feb 2002	Resolved possible reboot caused by Disturbance Recorder. Resolved possible reboot caused by invalid MODBUS requests. Enhancements to IEC 60870-5-103 build to include private codes, monitor blocking and disturbance record extraction. New uncompressed disturbance recorder for IEC 60870-5-103 build only. Correction to Courier NPS thermal reset command. Correction to IEC 60870-5-103 voltage measurements for Vn=380/480 V relays.	V2.05 or Later	P34x/EN T/C11
05	E	A/B	Mar 2002	Correction to foreign language text for System Backup protection not included in previous 05 software builds.	V2.05 or Later	P34x/EN T/C11
05	F	A/B	Oct 2002	DNP 3. 0 Object 12 "CROB" implementation is now compliant for simple function points. Correction to MODBUS CB Trip and Close via "0" command. Change to neutral voltage displacement protection and directional SEF protection so that they are not blocked by the VT supervision logic when the VN Input and ISEF>VNPol are selected as Measured. Correction to undervoltage stage 2 (V<2) setting range. The setting range has been increased from 10-70 V to 10-120 V (Vn=110/120 V) so that it is the same as V<1. Improvement to the RTD start-up calibration routine.	V2.05 or later	P34x/EN T/C11
05	1(F)	A/B	Oct 2002	IEC60870-5-103 build with special private code mapping for ALSTOM Power project in Iceland. Includes private codes and uncompressed disturbance recorder. Correction to IEC60870-5-103 voltage measurements for Vn=380/480 V relays. Correction to foreign language text for System Backup protection not included in previous 05 software builds. Change to neutral voltage displacement protection and directional SEF protection so that they are not blocked by the VT supervision logic when the VN Input and ISEF>VNPol are selected as Measured.	V2.05 or later	P34x/EN T/C11
05	1(F)	A/B	Oct 2002	Improvement to the RTD start-up calibration routine. IEC60870-5-103 build only.	V2.05 or later	P34x/EN T/C11

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	**Minor**					
05	G	A/B	Mar 2004	Control input states added to non-volatile memory. German language text updated. Power measurement limits added to prevent non zero values with no current and voltage. Also power factor measurements limited to +/-1. In the Commissioning Test menu the DDB status has been made visible on the front panel display. Support for Trip LED Status and Alarm Status added to G26 data type for MODBUS register 30001. Correction to the CB trip/Close functionality via MODBUS so that local/remote setting in the CB Control menu is not ignored. Correction to MODBUS auto event extraction which does not work correctly . DNP 3. 0 Object 12 “CROB” implementation is now compliant for simple function points. DNP 3. 0 object 10 added to class 0 poll. Correction to DNP 3. 0 time sync. operation so that it does not modify the season bit in the time stamp. Improvement to the differential protection performance at low frequencies.	V2.05 or Later	P34x/EN T/C11
05	G	A/B	Mar 2004	Correction to the manual reset user alarms so that the event record shows the alarm turning off only when a reset command has been issued. Previously the "alarm off" event is produced once the initiating signal is removed. Correction to the fault recorder window for current based trips so that it can terminate properly once the FAULT_REC_TRIG signal (DDB 288) is reset. Previously it needed to wait for Relay 3 to reset also before termination. DDB 649 for pole slip reactance line start removed from the event list. Resolved possible reboot caused by failure to time sync. from DNP 3. 0 when IRIG-B is active which is also providing the time sync. Now, any failure of the DNP 3. 0 to time sync. will only produce a maintenance record. Correction to French, German and Spanish language menu text for generator differential IS2 setting [3004] which incorrectly refers to the setting as IS1. Correction to the alarm and trip indication of the faulted phase(s) for the second stage of the undervoltage and overvoltage protection in the fault record information on the relay LCD. Correction to the C32CS error when extracting and saving an uncompressed disturbance record from the P34x through the front port using MiCOM S1 Studio. This only applies to P34x IEC60870-5-103 protocol builds since this is the only communication option that supports uncompressed disturbance records. The error is caused by unavailable opto inputs or relay contacts being assigned to digital inputs in the Disturbance Recorder menu.	V2.05 or Later	P34x/EN T/C11
05	G	A/B	Mar 2004	Resolved possible problem with disturbance recorder triggering which could cause loss of disturbance record data, temporary freezing of the user interface or loss of rear port communications. Resolved unreliable MODBUS framing. Resolved creation of spurious password expired event when menu cell or MODBUS register is accessed. Resolved error code 0x 8D840000.	V2.05 or Later	P34x/EN T/C11
05	H	A/B	Jun 2004	For Courier/DNP 3. 0/IEC60870-5-103 builds only. Correction to parity setting for MODBUS and DNP 3. 0 when the relay is powered up. Improvement to the self checking of the analog channels and SRAM.	V2.05 or later	P34x/EN T/C11
05	J	A/B	Jun 2004	For MODBUS builds only. Changes as for H. Improvement to the MODBUS driver to cope better with spurious data transmissions and failures of the relay to respond to commands where the server response time is fast.	V2.05 or later	P34x/EN T/C11

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
05	K	A/B	Jun 2005	MODBUS Time Transmission Format selectable via MODBUS only setting as Standard or Reverse for transmission of byte order.	V2.05 or later	P34x/EN T/C11
05	K	A/B	Jun 2005	V/Hz Protection drop-off/pick-up (DO/PU) ratio changed from 95% to 98%. DO/PU ratio changed from 95% to 98% for Over/Under Voltage protection. Trip threshold changed from 1. 05, 0. 95 Vs to 1 Vs for Over and Under Voltage and NVD protection. TMS setting of Under/Over Voltage protection reduced from 0. 5 to 0. 05. Correction to false frequency protection start at power-up. MODBUS driver modified to prevent relay reboot with error code 0x8C810000 in hardware A/B/C relays for 60Hz applications where fast polling and high baud rates are used. Modification to prevent reboot when large number of control and settings are sent to relay in quick succession over DNP 3. 0. IEC60870-5-103. Status of summer bit now works correctly in time sync. command. Correction to DNP 3. 0 software where settings download from MiCOM S1 Studio can fail for relays that have model dependent I/O configurations.	V2.05 or later	P34x/EN T/C11
05	L	A/B	July 2007	Correction to menu cell addressing for 05K. Version 05K software was built from 31 software to incorporate latest bug fixes. In doing this build of the 05K software the menu cell addressing changes that are in 06 software were included. These mainly affect the cell addresses of functions which have IDMT characteristics. The result is the default S1 files for 05 software are not compatible with a relay with 05K software. The 05L software fixes this problem so now the default S1 files for 05 software are compatible with a relay with 05L software.	V2.05 or later	P34x/EN T/C11
006	A	A/C	Aug 2000	Not released to production. Additional IDMT characteristics for overcurrent and voltage dependent overcurrent protection (rectifier and RI curve), earth fault protection (RI and IDG curve) and sensitive earth fault protection (IDG curve).	V2.06 or Later	P34x/EN T/D22
06	A	A/C	Aug 2000	Change to time dial setting range of IEEE and US curves. Previously curves were based on TD/7 where TD = 0. 5-15. Now, curves are based on TD where TD = 0. 01-100. Also, includes change to US ST Inverse (C02) curve. K constant and L constant multiplied x 7 because of change to TD, now K=0. 16758 and L=0. 11858. Angle measurements for sequence quantities in Measurements 1 menu added. Interturn protection added. Optional 2nd rear communication port added. New power supply with increased output rating and reduced dc inrush current (typically < 10A). (Model number hardware changed to suffix C). Wider setting range for Power and Sensitive Power protection. P>1/2 (reverse power) and P<1/2 (low forward power) maximum setting changed from 40 In to 300 In W (Vn=100/120 V) and from 160 In W to 1200 In W (Vn=380/480 V). Sen. –P>1/2 and Sen. P<1/2 maximum setting changed from 15 In to 100 In W (Vn=100/120 V) and from 60 In to 400 In W (Vn=380/480 V). There is also an additional setting for the Power and Sensitive Power protection to select the Operating mode as Generating or Motoring. Wider setting range for the voltage dependent overcurrent protection. Volt Dep. OC V<1 and V<2 minimum setting changed from 20 to 5 V (Vn=100/120 V) and from 80 to 20 V (Vn=380/480 V). V Dep. OC k Set minimum setting changed from 0. 25 to 0. 1. Maximum overfrequency protection setting increased from 65 to 68 Hz.	V2.06 or Later	P34x/EN T/D22

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
06	A	A/C	Aug 2000	Change to undervoltage stage 2 (V<2) setting range to correct an error. The setting range has been increased from 10-70 V to 10-120 V (Vn=100/120 V) so that it is the same as V<1. Change to neutral voltage displacement protection and directional SEF protection so that they are now not blocked by the voltage transformer supervision logic when the VN Input and ISEF> VN Pol are selected as Measured. Includes all the improvements and corrections in 05F software except for 2 enhancements shown for 06B.	V2.06 or Later	P34x/EN T/D22
06	B	A/C	Oct 2002	Correction to undervoltage stage 2 (V<2) setting range. The setting range has been increased from 10-70 V to 10-120 V (Vn=110/120 V) so that it is the same as V<1. Enhancements to IEC60870-5-103 build to include private codes, monitor blocking and disturbance record extraction. New uncompressed disturbance recorder for IEC60870-5-103 build only. Improvement to the RTD start-up calibration routine.	V2.06 or Later	P34x/EN T/D22
06	C	A/C	Mar 2004	Changes are the same as 05G.	V2.06 or Later	P34x/EN T/D22
06	D	A/C	Jun 2004	For Courier/DNP 3. 0/IEC60870-5-103 builds only. Correction to parity setting for MODBUS and DNP 3. 0 when the relay is powered up. Improvement to the self checking of the analogue channels and SRAM.	V2.06 or later	P34x/EN T/D22
06	D	A/C	Jun 2004	Minor bug fixes.	V2.06 or later	P34x/EN T/D22
06	E	A/C	Jul 2004	For MODBUS builds only. Changes as for D. Improvement to the MODBUS driver to cope better with spurious data transmissions and failures of the relay to respond to commands where the server response time is fast.	V2.06 or later	P34x/EN T/D22
06	F	A/C	Jun 2005	Changes are the same as 05K.		
06	G	A/C	July 2009	This release is specific for Hydro Quebec (HQ) to provide a P343 relay with modified single phase sensitive power protection which uses B Phase to calculate sensitive power as apposed to A-Phase in the standard software versions.	V2.06 or later	P34x/EN T/D22
07	A	A/C	Apr 2003	Not released to production. Optional additional 4 analog inputs and 4 outputs (current loop inputs and outputs - CLIO). Additional setting to select the current inputs (IA-1, IB-1, IC-1 or IA-2, IB-2, IC-2) used for the breaker fail undercurrent. Two new hardware configurations - (1) 32 Inputs, 16 Outputs, RTD, CLIO (2) 16 Inputs, 32 Outputs, RTD, CLIO. Number of alarms increased from 64 to 96 (New Alarm Status 3 word - 32 bit). Additional user alarms. Previously 1 manual reset and 2 self reset user alarms, now 12 manual reset and 4 self reset user alarms. Control Input states added to non volatile memory. German language text updated. Courier and MODBUS builds only.	V2.09 or Later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
07	A	A/C	Apr 2003	Minor bug fixes.	V2.09 or Later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
07	B	A/C	Oct 2003	Power measurement limits added to prevent non zero values with no current and voltage. Also power factor measurements limited to +/-1. In the Commissioning Test menu the DDB status has been made visible on the front panel display. Support for Trip LED Status and Alarm Status added to G26 data type for MODBUS register 30001. Correction to the CB trip/Close functionality via MODBUS so that local/remote setting in the CB Control menu is not ignored. Correction to MODBUS auto event extraction which does not work correctly in versions 05 and 06 software. Extension of the control input functionality to support pulse and latch operations in DNP3. 0. DNP 3. 0 object 10 added to class 0 poll. Correction to DNP 3. 0 time sync. operation so that it does not modify the season bit in the time stamp. Improvement to the differential protection performance at low frequencies.	V2.09 or Later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
07	B	A/C	Oct 2003	Correction to the manual reset user alarms so that the event record shows the alarm turning off only when a reset command has been issued. Previously the "alarm off" event is produced once the initiating signal is removed. Correction to the fault recorder window for current based trips so that it can terminate properly once the FAULT_REC_TRIG signal (DDB 288) is reset. Previously it needed to wait for Relay 3 to reset also before termination. DDB 649 for pole slip reactance line start removed from the event list.	V2.09 or Later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
07	C	A/C	Mar 2004	Resolved possible reboot caused by failure to time sync. from DNP 3. 0 when IRIG-B is active which is also providing the time sync. Now, any failure of the DNP 3. 0 to time sync. will only produce a maintenance record. Correction to French, German and Spanish language menu text for generator differential IS2 setting [3004] which incorrectly refers to the setting as IS1. Correction to the alarm and trip indication of the faulted phase(s) for the second stage of the undervoltage and overvoltage protection in the fault record information on the relay LCD.	V2.09 or Later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
07	C	A/C	Mar 2004	Correction to the C32CS error when extracting and saving an uncompressed disturbance record from the P34x through the front port using MiCOM S1 Studio. This only applies to P34x IEC60870-5-103 protocol builds since this is the only communication option that supports uncompressed disturbance records. The error is caused by unavailable opto inputs or relay contacts being assigned to digital inputs in the Disturbance Recorder menu. Resolved possible problem with disturbance recorder triggering which could cause loss of disturbance record data, temporary freezing of the user interface or loss of rear port communications. Resolved unreliable MODBUS framing. Resolved error code 0x 8D840000.	V2.09 or Later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
07	D	A/C	Jun 2004	For Courier/DNP 3. 0/IEC60870-5-103 builds only. Correction to parity setting for MODBUS and DNP 3. 0 when the relay is powered up . Improvement to the self checking of the analog channels and SRAM.	V2.09 or later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
07	E	A/C	Jul 2004	For MODBUS builds only. Changes as for D. Improvement to the MODBUS driver to cope better with spurious data transmissions and failures of the relay to respond to commands where the server response time is fast.	V2.09 or later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
07	E	A/C	Jul 2004	Minor bug fixes.	V2.09 or later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
07	F	A/C	Jun 2005	Changes are the same as 05K.	V2.09 or later	P34x/EN T/E33 (ALSTOM) or P34x/EN T/F33 (AREVA)
30	A	J	Nov 2004	Not released to production. Enhanced main processor board. Company name change. 'ALSTOM' changed to 'MiCOM' in default Plant Reference cell and 'ALSTOM P' changed to 'MiCOM P' for ASDU5 message type, IEC protocol. User interface enhancements - larger 100x33 pixel graphical display of 3 lines x 16 characters + 2 new buttons, direct access keys. Control input enhancements. Selection of latched or pulsed mode, control input labels added, disturbance recorder trigger from control inputs. 16 PSL Timers (previously 8). Platform alarms mapped to the DDB (Alarm Status 3). Time synchronization using an opto input. Opto input power frequency filter control, enabled/disabled.	V2.11 or later	P34x/EN M/G44
30	A	J	Nov 2004	Courier over EIA(RS)485 can be selected for the 1st rear port in addition to existing K-Bus configuration. Transmission of the first rear port protocols (MODBUS/Courier/DNP3. 0) using the fiber-optic port (IEC60870-5-103 previously available). Uncompressed disturbance recording added for Courier/MODBUS/DNP 3. 0 (added to IEC60870-5-103 protocol in 05D, 06B software). Dual Characteristic DO/PU ratio Opto Inputs (DO/PU = 60/80% or 50/70%). 512 Event records (previously 250). DNP3 evolution. Scan interval for binary inputs (object 01) reduced from 5s to 0. 5s. Scan interval for analog inputs (object 30) reduced from 2s to 1s. Improved minimum step size of analog input dead bands. MODBUS Time Transmission Format selectable as Standard or Reverse for transmission of byte order. V/Hz Protection drop-off/pick-up (DO/PU) ratio changed from 95% to 98%. DO/PU ratio changed from 95% to 98% for Over/Under Voltage protection. Trip threshold changed from 1. 05, 0. 95 Vs to 1 Vs for Over and Under Voltage and NVD protection. TMS setting of Under/Over Voltage protection reduced from 0. 5 to 0. 05. CT Supervision for 2nd set of 3 phase CTs. Previously only IA/IB/IC inputs supervised.	V2.11 or later	P34x/EN M/G44
30	A	J	Nov 2004	Default labels changed for the digital inputs and outputs in Input Labels and Output Labels menu. Changed to be more generic - Input Lx, Output Rx. Correction to false frequency protection start at power-up. IEC60870-5-103. Status of summer bit now works correctly in time sync command.	V2.11 or later	P34x/EN M/G44
30	B	J	Dec 2004	Modification to prevent reboot when large number of control and settings are sent to relay in quick succession over DNP 3. 0. Correction to 2nd rear comms. port channel failure for P34xxxxxxxxxxJ relays only.	V2.11 or later	P34x/EN M/G44

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
31	A	J	Apr 2005	New relay model available, the P344 (80TE case only). The P344 is based on the P343 but has an additional neutral voltage input, VN2, to provide 2 measured neutral voltage protection functions (59N) for earth fault and interturn protection. 4 stages of directional overcurrent protection (67). Previous P342/P343/P344 software versions included 2 stages of non directional overcurrent protection. 1 stage of definite time negative phase sequence overpower protection (S2=I2xV2)(32NPS). This is used in China as an interlocking signal for the neutral voltage interturn protection. Independent derived/measured neutral voltage protection (59N). P341/P342/P343 has 2 stages of measured and 2 stages of derived neutral voltage protection	V2.11 or later	P34x/EN M/G44
31	A	J	Apr 2005	P344 has 2 measured neutral voltage inputs and so has 2x2 stages of measured and 2 stages of derived neutral voltage protection. Previous software versions included 2 stages of measured or derived neutral voltage protection. 6 bands of generator abnormal frequency protection (81AB). Similar to P94x 81AB function. 1 definite time stage of negative phase sequence overvoltage protection (47). Same as P14x (47) function. 4 definite time stages of negative phase sequence overcurrent protection (46OC). Same as P14x (46OC) function. P342/P343 minimum three phase power settings reduced to 0. 5%Pn, previously 2%Pn. P344 3-phase power setting range is as new P343 setting range. 3 additional definite time delayed overfluxing protection stages. The inverse time overfluxing characteristic has been modified to make it more consistent with competitors and to aid future enhancements. The overfluxing protection now comprises of 1 definite time alarm + 1 inverse/DT trip stage + 3 definite time trip stages. Correction to DNP 3. 0 software where settings download from MiCOM S1 Studio can fail for relays that have model dependent I/O configurations.	V2.11 or later	P34x/EN M/G44
32	A	J	Mar 2006	Not released to production. Phase rotation function added. Can select phase rotation as ABC or ACB for all 3 phase current and voltage inputs. Can also individually select which 2 phases are swapped for any of the 3 phase current and voltage inputs. New menu column 'System Config' with phase rotation settings. 'Gen Diff' menu column moved to make way for 'System Config' menu. In the disturbance recorder the maximum number of analogue channels that can be recorded is increased so that all analogue inputs can be recorded. Number of analogue channels is increased from 8 to 9/12/13 for P342/P343/P344. Number of PSL DDB signals increased from 1023 to 1408 and DDBs re-organized. This means that the PSL created in version 32 software is not compatible to PSL created in previous software versions and vice versa. Setting Group selection via 2 new DDB signals makes it possible to select a setting group via any opto input or remotely via a Control Input. Previously, the 4 setting groups could be selected using fixed opto inputs, 1 and 2. An 'Any Trip' DDB has been created to allow any contact(s) to be used as the trip indication. Previously, the Any Trip signal was defined as operation of Relay contact 3. The Any Trip signal operates the Trip LED, initiates the breaker fail logic and maintenance counters and is used in the fault recorder logic. Minor changes to description of CT and VT Ratio settings. Number of maintenance records increased from 5 to 10.	V2.14 or later	P34x/EN M/G44 P34x/EN AD/G54

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
32	A	J	Mar 2006	Inter frame gap added between frames in multi-frame transmission of DNP 3. 0 messages to be compatible with C264. Correction to error in NPS directional overcurrent operating time delay. The excess in the operating time (always less than 1s) only occurs when set to directional. Correction to intermittent incorrect IRIG-B status indication of 'Card Failed' with healthy IRIG-B source.	V2.14 or later	P34x/EN M/G44 P34x/EN AD/G54
32	B	J	May 2006	Minor bug fixes.	V2.14 or later	P34x/EN M/G44 P34x/EN AD/G54
32	C	J	Oct 2006	New P345 relay model. The P345 includes the same functions as the P344 plus 100% stator earth fault protection via low frequency injection. The P345 also includes a new front panel with 10 function keys and 10 associated programmable LEDs. All 18 of the P345 programmable LEDs are tri-color and can be set as red, yellow or green in the PSL. P345 not released to production. MODBUS allows individual 16 bit register pairs that make up 32 bit data to be accessed individually. Correction to fast operation of overcurrent protection with IEEE/US inverse time reset characteristic.	V2.14 or later	P34x/EN M/H65
32	D	J	Dec 2006	Correction to P34x Directional Sensitive Earth Fault (Forward or reverse) function. Function does not operate if SEF/REF Protection is initially disabled in the configuration column and SEF Mode is set to 'SEF' (default setting) when the relay is booted up. Correct operation will only occur when the SEF Mode setting is changed (submitted) and changed back to 'SEF' or the relay is rebooted with SEF/REF enabled in the configuration column.	V2.14 or later	P34x/EN M/H65
32	E	J	April 2007	P343 IEC61850 added. IEC61850 not released to production.	V2.14 or later	P34x/EN M/H65
32	F	J/K	May 2007	New P345 relay model released to production. The P345 includes the same functions as the P344 plus 100% stator earth fault protection via low frequency injection. The P345 also includes a new front panel with 10 function keys and 10 associated programmable LEDs. All 18 of the P345 programmable LEDs are tri-color and can be set as red, yellow or green in the PSL . Improvement made to 100% stator earth fault (64S) measurement algorithm to improve accuracy. '64S Series X' setting removed and new '64S Fail' DDB (1076) added. Correction to VT secondary ratio setting for 32 software relays, Vn = 380/480 V rating. With a 1:1 VT ratio on a 380/480 V P340 relay with 32 software installed after power up the analogue quantities are 4 times too large. The error is corrected by re-appying the VT secondary (which is showing the correct value) setting. Local time zone adjustments for daylight saving time added to Date and Time menu.	V2.14 or later	P34x/EN M/H65
32	G	J/K	Sept 2007	Correction to CT secondary ratio setting for 32F software relays. When relay is powered off and on the secondary CT ratio is applied incorrectly for a 5A rating such that currents measured are 5 times too small. CT ratio is applied correctly if settings re-applied when relay is powered on. Correction to incorrect year being set when date and time is set via the user interface with IRIG-B active.	V2.14 or later	P34x/EN M/H65
32	H	J/K	Nov 2007	Correction to the CT ratio scaling for 32 software relays. If the CT ratio secondary settings are set to 5A and the relay rebooted, if the setting group is changed the CT secondary scaling reverts to 1A.	V2.14 or later	P34x/EN M/H65

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
32	J	J/K	Dec 2007	IEC 61850 communications added. Support released for high break contacts and un-modulated IRIG-B in all P34x relays. P34x relays can be ordered with modulated or un-modulated IRIG-B and with 4 or 8 high break contacts depending on the model.	V2.14 or later	P34x/EN M/H65
32	K	J/K	May 2008	Correction to VT ratio problem. The VT ratio, if modified, is reset back to default values when the P345 relay is rebooted. This in turn causes the measurements to effectively display 'secondary' quantities as it now has a 1:1 ratio. This problem does not affect protection operation because the relay operates on 'per unit' quantities, which are unchanged. The primary and secondary ratios are used to scale the measurements and settings for display, communication and recording.	V2.14 or later	P34x/EN M/H65
33	A	J/K	June 2008	Rotor earth fault protection added to P342/P343/P344/P345 when CLIO card is fitted. Rotor earth fault function also requires P391 low frequency injection, coupling and measurement unit. DNP 3. 0 enhancements: configurable points table, default variations, SBO timeouts, integer scaling, floating point analogue values, disturbance record extraction, remote settable deadbands and class assignment, configurable message length and timeouts, data link confirmation, alias control inputs. Support for Russian language added. This is now an order option. PSL positional data is now downloaded to the relay with the logic so that when the PSL is extracted from the relay the positional data of signals etc is the same as when downloaded. Support for set/reset latches in the PSL added.	V 3.0 (Studio) or later	P34x/EN M/I76
33	B	J/K	March 2009	Correction to ISEF and IN Secondary CT ratio scaling incorrectly being applied if both not set to the same value (1A or 5A) - P345 only, P341/2/3/4 not affected.	V 3.0 (Studio) or later	P34x/EN M/I76
33	C	J/K	June 2009	Correction to Residual O/V NVD protection where derived neutral voltage is used for all protection stages (VN>1/2/3/4/5/6) instead of VN>1/2 (derived), VN>2/3 (VN1 input, measured), VN>5/6 (VN2 input, measured, P344/5 only). This bug only affect 33B software.	V 3.0 (Studio) or later	P34x/EN M/I76
33	D	J/K	Feb 2010	Correction to several IEC61850 modeling issues for phase 1 of IEC 61850. (1) Correction to missing measurements (VN/IN Derived Mag/Angle, NPS Thermal, V/Hz) and incorrect sourcing in the P340 IEC 61850 Phase 1 data model implementation. (2) Correction to DDB signal status which is not available to 61850 model when events are configured to be filtered out. (3) Correction to some of the strings for the Data Attributes under the 'NamPlt' Data Object under LLN0 (only) of some of the Logical Devices.	V 3.0 (Studio) or later	P34x/EN M/I76
35	A	J/K	Dec 2009	Redundant Ethernet port option (IEC61850). IEC 61850 Phase 3 enhancements:Controls - Direct Control, Direct Control with enhanced security, Select Before Operate (SBO) with enhanced security, Eight Buffered Report Control Blocks and sixteen Unbuffered Report Control Blocks, Configurable Data Sets, Published GOOSE messages, Uniqueness of control, Select Active Setting Group, Quality for GOOSE, Address List, Originator of Control, Energy measurements and Reset controls for demand and thermal measurements using the MMTR Logical Node, Unit multipliers for all measurements. Read Only Mode for remote communications ports added. Correction to DDB signal status not being available to 61850 model when events are configured to be filtered out. Correction to some of the strings for the IEC61850 Data Attributes under the 'NamPlt' Data Object under LLN0 (only) of some of the Logical Devices.	V 3.0 (Studio) or later	P34x/EN AD/I86

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
35	B	J/K	Nov 2010	Improvements to IEC61850 comms fixing problems as described below:. (1) A short on/off pulse state may cause the interim stage change to be not reported. (2) Occasionally an opto-input change of state is not registered in System\OptGGIO1. ST. (3) Applying XCBR1. CO. Pos Open/Close can cause the relay to reply with Invalid Position even though the Open/Close operation is successful . (4) IEC61850 communications can terminate after operating a control with control status in RCB . (5) IEC61850 buffered reporting stops working after a period of time when applying several faults to generate reports.	V 3.0 (Studio) or later	P34x/EN AD/I86
36	B	J/K	Nov 2010	Transformer Differential protection, Differential CT Supervision and Circuitry Fault Alarm functions added to P343/P344/P345. Transformer thermal overload and Loss of Life functions added, based on the IEEE Standard C57. 91-1995. Transformers Through Fault monitoring added. Check synchronization and CB Control functions added. 4 definite time stages of df/dt protection added. Selectable CT source - IA-1/IB-1/IC-1 or IA-2/IB-2/IC-2 for Overcurrent, NPS Overcurrent, Restricted Earth Fault, NPS Power and Dead Machine protection added. CT Polarity - Standard/Inverted added. Low Impedance biased restricted earth fault protection improved by addition of transient bias to make more stable for through faults. Improved undercurrent detector algorithm for CB Fail protection added. Support for Chinese language added. This is now an order option. Chinese HMI requires two language blocks so only 2 other languages are supported, by default these are English and French . IEC60870-5-103 generic services added. This enables all measurements to be available with this protocol. New front panel for P343/P344 the same as P345 with 18 tri-color leds and 10 function keys (K hardware - P34xxxxxxxxxxxK). Number of PSL DDB signals increased from 1407 to 2047.	V 3.0 (Studio) or later	P34x/EN M/I96

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
36	U	J/K	Mar 2011	Schneider Electric-related changes:. New design of front cover for the manual. Safety Information section (entire chapter) replaced with a generic version which covers several different products. 1. Introduction (entire chapter) replaced with a new chapter which includes reference to Schneider Electric. 3. Getting Started chapter edited to include reference to Schneider Electric. 6. Application Notes chapter edited to include reference to Schneider Electric. 8. Measurements and Recording chapter edited to include reference to Schneider Electric. 9. Firmware Design chapter edited to include reference to Schneider Electric. 10. Commissioning chapter edited to include reference to Schneider Electric. 11. Maintenance chapter edited to include reference to Schneider Electric. 12. Troubleshooting (entire chapter) replaced with a new chapter to include reference to Schneider Electric. Repair/Modification Return Authorization Form added for Schneider Electric. 13. SCADA Communications chapter edited to include reference to Schneider Electric. 15. Installation chapter edited to include reference to Schneider Electric. Other company logos removed from drawings. New design of back cover for the manual. Other changes:. New template used to modernise the page layouts of the manual. 1. Introduction chapter - information added regarding the P342 cortec. Text changes to make text easier to read. Unique reference number applied to all figures.	V 3.0 (Studio) or later	P34x/EN M/J96
36	V	J/K	Sept 2011	Minor bug fixes.	V 3.0 (Studio) or later	P34x/EN M/J96
36	W	J/K	Mar 2012	Minor bug fixes.	V 3.0 (Studio) or later	P34x/EN M/J96
36	X	J/K	Jun 2013	Implements the PRP redundancy protocol and increase hardware option N and P. Minor bug fixes.	V 3.0 (Studio) or later	P34x/EN M/J96
36	Y	J/K	Jun 2014	Minor bug fixes.	V 3.0 (Studio) or later	P34x/EN M/La7

Software Version		Hardware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Documen-tation
Major	Minor					
B0	A	L/M	June 2015	**Hardware:** Update design suffix to CPU3/XCPU3 **Software:** Former Cyber Security Phase 1 IEC 61850 Ed.2 and ED.1 Goose performance and number improvement HSR/PRP Redundancy Dual communication with 2 IPs Correction of these issues: Fixed and enhanced various small issues.	V 5.0.1 (Studio) or later	P34x/EN M/La7
B1	A	L/M	Nov 2015	Sensitive power protection enhancement	V 5.0.1 (Studio) or later	P34x/EN M/Mb7
B2	A	L/M	June 2017	New protocol IEC61850 Edition 1 / 2 and DNPoE and DNP3 Serial. RBAC Cyber Security 3 This release integrated the Cyber Security RBAC and provided the option for the user if they want/don't want to use the Cyber Security which depends on the protocol options. CLS0 - Simple password management - No Security Administration Tool (SAT) required. CLS1 - Advanced user account right management, security logs/events and secure administration capability - Security Administration Tool (SAT) required. Courier Tunneling via Secured Communication Latest Fault Record via DNPoE and IEC61850. 32 User Alarms Virtual I/O Naming New DDB: Logic 0 and IRIGB Valid	V 7.1.0 (Studio) or later	P34x/EN M/Nc7

The Easergy Studio (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 Easergy Studio (MiCOM S1 Studio).**

2 RELAY SOFTWARE VERSION

2.1 Relay Software and Setting File Software Versions

Setting File Software Version	Relay Software Version																
	01	02	03	04	05	06	07	30	31	32A-C	32D-L	33	35	36	B0	B1	B2
01	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×
02	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×
03	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×
04	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×
05	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×
06	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×
07	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×
30	×	×	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×
31	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×
32A-C	×	×	×	×	×	×	×	×	×	✓	✓	✓	×	×	×	×	×
32D-L	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×	×	×
33	×	×	×	×	×	×	×	×	×	×	×	✓	✓	✓	×	×	×
35	×	×	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×
36	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×
B0	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×
B1	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×
B2	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓

2.2 Relay Software and PSL File Software Versions

PSL File Software Version	Relay Software Version																	
	01	02	03	04	05	06	07	30	31	32 A-B	32 C-H	32 J-L	33	35	36	B0	B1	B2
01	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
02	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
03	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
04	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
05	×	×	×	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×
06	×	×	×	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×
07	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×
30	×	×	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×
31	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×
32A-B	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×
32C-H	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×
32J-L	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×
33	×	×	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×	×
35	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×
36	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×
B0	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×
B1	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×
B2	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓

Note 1: 05, 06 PSL compatible with 07 PSL except for user alarm DDBs

2.3 Relay Software and Menu Text File Software Versions

Menu Text File Software Version	Relay Software Version																					
	01	02	03	04	05 A-E	05 F-J	05K	06 A-E	06F	07 A-E	07F	30	31	32 A-B	32 C-D	32 E-L	33	35	36	B0	B1	B2
01	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
02	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
03	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
04	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
05A-E	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
05F-J	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
05K	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
06A-E	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
06F	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
07A-E	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
07F	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
30	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
31	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗
32A-B	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗
32C-D	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗
32 E-L	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗
33	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗
35	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗
36	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗	✗
B0	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗
B1	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗
B2	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓

Note *Menu text remains compatible within each software version (except 05/06/07) but is NOT compatible across different versions.*

SYMBOLS AND GLOSSARY

CHAPTER SG

<table>
<tr><td>Date</td><td colspan="2">09/2016</td></tr>
<tr><td>Products covered by this chapter:</td><td colspan="2">This chapter covers the specific versions of the MiCOM products listed below. This includes only the following combinations of Software Version and Hardware Suffix.</td></tr>
<tr><td>Hardware Suffix</td><td colspan="2">All MiCOM Px4x products</td></tr>
<tr><td>Software Version</td><td colspan="2">All MiCOM Px4x products</td></tr>
<tr><td>Connection Diagrams:</td><td>P14x (P141, P142, P143 & P145):
10P141xx (xx = 01 to 02)
10P142xx (xx = 01 to 05)
10P143xx (xx = 01 to 11)
10P145xx (xx = 01 to 11)
P24x (P241, P242 & P243):
10P241xx (xx = 01 to 02)
10P242xx (xx = 01)
10P243xx (xx = 01)
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)
P44x (P441, P442 & P444):
10P44101 (SH 1 & 2)
10P44201 (SH 1 & 2)
10P44202 (SH 1)
10P44203 (SH 1 & 2)
10P44401 (SH 1)
10P44402 (SH 1)
10P44403 (SH 1 & 2)
10P44404 (SH 1)
10P44405 (SH 1)
10P44407 (SH 1 & 2)
P44y (P443 & P446):
10P44303 (SH 01 and 03)
10P44304 (SH 01 and 03)
10P44305 (SH 01 and 03)
10P44306 (SH 01 and 03)
10P44600
10P44601 (SH 1 to 2)
10P44602 (SH 1 to 2)
10P44603 (SH 1 to 2)</td><td>P54x (P543, P544, P545 & P546):
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)
P547:
10P54702xx (xx = 01 to 02)
10P54703xx (xx = 01 to 02)
10P54704xx (xx = 01 to 02)
10P54705xx (xx = 01 to 02)
P64x (P642, P643 & P645):
10P642xx (xx = 1 to 10)
10P643xx (xx = 1 to 6)
10P645xx (xx = 1 to 9)
P74x (P741, P742 & P743):
10P740xx (xx = 01 to 07)
P746:
10P746xx (xx = 00 to 21)
P841:
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)
P849:
10P849xx (xx = 01 to 06)</td></tr>
</table>

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 in the context of the 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 in the context of the protection element
Business Service Layer	This layer coordinates the application, processes commands, make logical decision and calculation according to the business rules
CA	Certification Authority
CAT	Computer 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 in the context of protection element. Could be labelled 50BF in ANSI terminology.
CDC	Common Data Class
CET	Sepam Configuration tool
CF	Control Function
Ch	Channel: usually a communications or signaling channel

Term	Description
Check Synch	Check Synchronizing function
CID	Configured IED Description
CIFS	Common Internet File System. Microsoft protocol use to share resources on a network.
CIP	Critical Infrastructure Protection
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
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.
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	Double or Doubly Attached Node
DANH	Double or Doubly Attached Node with HSR protocol
DANP	Double or Doubly Attached Node implementing PRP
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

Term	Description
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 protection scheme. Could be labeled 67N in ANSI terminology.
df/dt	Rate of Change of Frequency (equivalent to ROCOF). Could be labeled 81R in ANSI terminology.
df/dt>1	First stage of df/dt in the context of protection element
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 in the context of protection elements . Could be labeled 87 in ANSI terminology.
DIN	Deutsches Institut für Normung (German standards body)
Dist	Distance in the context of protection elements . Could be labeled 21 in ANSI terminology.
DITA	Darwinian Information Typing Architecture
DLDB	Dead-Line Dead-Bus: In system synchronism check, indication that both the line and bus are de-energized.
DLLB	Dead-Line Live-Bus: In system synchronism check, indication that the line is de-energised whilst the bus is energized.
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. Or Abbreviation of “Dead Time” in the context of auto-reclose:
DTD	Document Type Definition
DTOC	Definite Time Overcurrent in the context of protection element
DTS	Date and Time Stamp
DVC	Direct Variable Cost
DZ	Dead Zone. Area between a CT and an open breaker or an open isolator.
EF or E/F	Earth Fault (directly equivalent to Ground Fault)
EIA	Electronic Industries Alliance

Term	Description
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.
FWD, Fwd or Fwd.	Indicates an element responding to a flow in the “Forward” direction
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 in the context of 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.
GUI	Graphical User Interface
HIPS	Host Intrusion Prevention System based on “white list” of accepted executables.
HMI	Human Machine Interface
HSR	High Availability Seamless Redundancy
HTML	Hypertext Markup Language

Term	Description
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. 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 or Instrumentation Systems and Automation Society
ISO	International Standards Organization
JPEG	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 relay front-panel text display.
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
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
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

Term	Description
MAC	Media Access Control or Mandatory Access Control
MC	MultiCast
MCB	Miniature Circuit Breaker
MIB	Management Information Base
MICS	Model Implementation Conformance Statement
MMF	Magneto-Motive Force
MMS	Manufacturing Message Specification (IEC 61850)
MRP	Media Redundancy Protocol
MU	Merging Unit (function)
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
OOS	Out-Of-Step
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
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

Term	Description
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, could be labeled 78 in ANSI terminology.
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).
PURR	A Permissive Underreaching Transfer Trip scheme (alternative terminology: PUR).
Q	Quantity defined as per unit value
Qx	Isolator number x
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 path.
RBPh	Lead burden for the phasepath.
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.
RoCoF	Rate of Change of Frequency
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)
RST or Rst	Reset generally used in the context of reset functions in circuit breaker control.
RSTP	Rapid Spanning Tree Protocol.
RTCS	Real Time Certificate Status. Facility. An IETF draft for online certificates validation.
RTD	Resistance Temperature Device
RTU	Remote Terminal Unit

Term	Description
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.
SAMU	Stand Alone Merging Unit (device)
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.
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 in the context of protection element. Could be labeled 87N in ANSI terminology.
SEF	Sensitive Earth Fault in the context of protection element
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
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
SP	Single pole.
SPAR	Single pole auto-reclose.

Term	Description
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	Static Var Compensator
SVM	Sampled Value Model
TAF	Turbine Abnormal Frequency
TAT	Transfer Administration Tool
TBD	To Be Defined
TCP	Transmission Control Protocol
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
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
UPCT	User Programmable Curve Tool
UTC	Universal Time Coordinated
V	Voltage

Term	Description
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 Double 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 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

Term	Description
Courier	Schneider Electric’s proprietary SCADA communications protocol
Easergy	Schneider Electric’s brand of protection relays and related software products
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 (∧ 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	

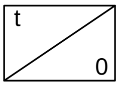
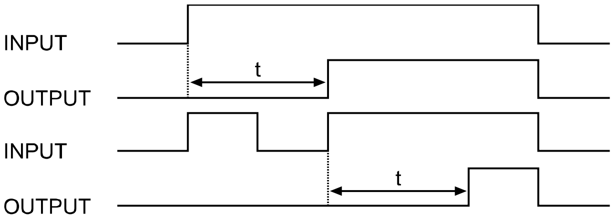
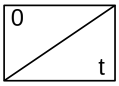
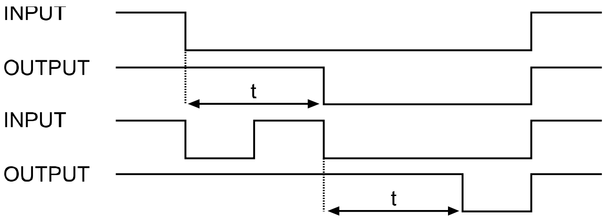
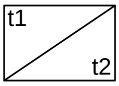
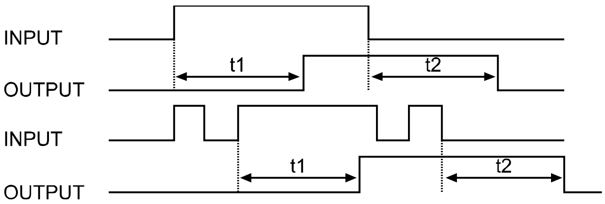
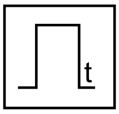
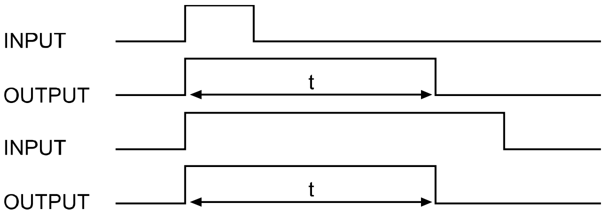
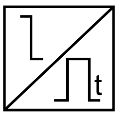
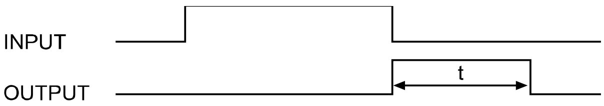
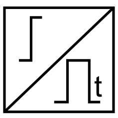
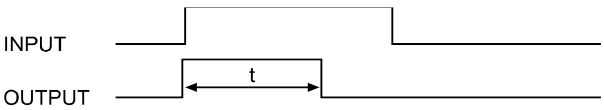
Symbol	Description	Units
K_1	Lower bias slope setting of biased differential element	%
K_2	Higher bias slope setting of biased differential element	%
KCZ	Slope of the differential phase element for the Check Zone.	
K_e	Dimensioning factor for earth fault	
km	Distance in kilometers	
K_{max}	Maximum dimensioning 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	

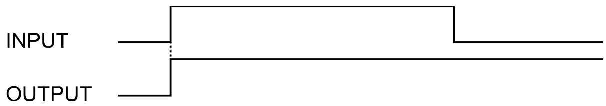
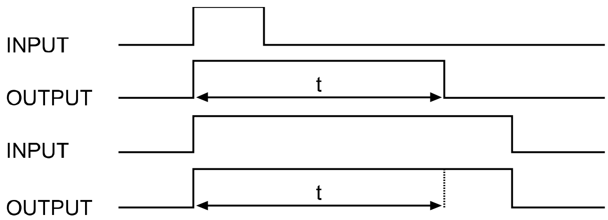
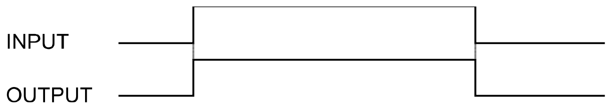
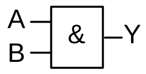
Logic symbols	Explanation	Time chart
Latching	Latch	
Dwell Timer	Dwell timer	
Straight	Straight (non latching): Hold value until input reset signal	

Table 9 - Logic Timers

9 LOGIC GATES

AND GATE

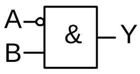
Symbol



Truth Table

IN		OUT
A	B	Y
0	0	0
0	1	0
1	0	0
1	1	1

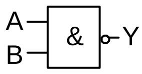
Symbol



Truth Table

IN		OUT
A	B	Y
0	0	0
0	1	1
1	0	0
1	1	0

Symbol



Truth Table

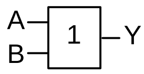
IN		OUT
A	B	Y
0	0	1
0	1	1
1	0	1
1	1	0

P4424ENb

Figure 1 - Logic Gates - AND Gate

OR GATE

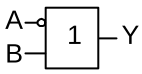
Symbol



Truth Table

IN		OUT
A	B	Y
0	0	0
0	1	1
1	0	1
1	1	1

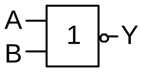
Symbol



Truth Table

IN		OUT
A	B	Y
0	0	1
0	1	1
1	0	0
1	1	1

Symbol



Truth Table

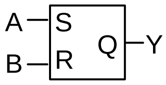
IN		OUT
A	B	Y
0	0	1
0	1	0
1	0	0
1	1	0

P4424ENc

Figure 2 - Logic Gates - OR Gate

R – S FLIP-FLOP

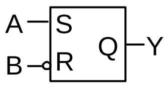
Symbol



Truth Table

A	B	QN	QN+	Active Mode
0	0			Hold Mode
0	1	0		Hold Mode
		1	0	Reset
1	0	0	1	Set
		1		Hold Mode
0	0	-	-	Inhibit Mode

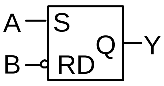
Symbol



Truth Table

A	B	QN	QN+	Active Mode
0	0	0		Hold Mode
		1	0	Reset
0	1			Hold Mode
1	0	-	-	Inhibit Mode
0	1	0	1	Set
		1		Hold Mode

Symbol



* RD = Reset Dominant

Truth Table

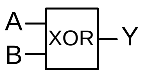
A	B	QN	QN+	Active Mode
0	0			Hold Mode
0	1			0
1	0	0	1	Set
		1		Hold Mode
1	1			0

P4424ENd

Figure 3 - Logic Gates - R-S Flip-Flop Gate

EXCLUSIVE OR GATE

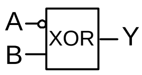
Symbol



Truth Table

IN		OUT
A	B	Y
0	0	0
0	1	1
1	0	1
1	1	0

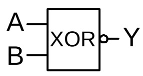
Symbol



Truth Table

IN		OUT
A	B	Y
0	0	1
0	1	1
1	0	0
1	1	1

Symbol



Truth Table

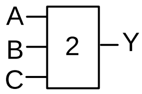
IN		OUT
A	B	Y
0	0	1
0	1	0
1	0	0
1	1	1

P4424ENe

Figure 4 - Logic Gates - Exclusive OR Gate

PROGRAMMABLE GATE

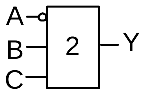
Symbol



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

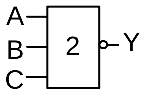
Symbol



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

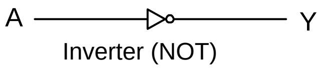
IN			OUT
A	B	C	Y
0	0	0	1
0	0	1	1
0	1	0	1
0	1	1	0
1	0	0	1
1	0	1	0
1	1	0	0
1	1	1	0

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:

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