OFGEM

REPORT ON SUPPORT INVESTIGATIONS INTO RECENT BLACKOUTS IN LONDON AND WEST MIDLANDS

VOLUME 2
SUPPLEMENTARY REPORT

PROTECTION COMMISSIONING & PERFORMANCE

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CONTENTS

Page No.

APPENDICES:

APPENDIX A	–	MC 3 & NEW CROSS 2 COMMISSIONING RECORD ANALYSIS FOR WIMBLEDON

✂

APPENDIX C	–	NGC BACK-UP PROTECTION PERFORMANCE STATISTICS OVER THE LAST 10 YEARS
APPENDIX D	–	EXTRACT – 1988 CEGB REPORT ON "SUPERGRID SYSTEM BACK-UP PROTECTION"
APPENDIX E	–	LOSSES OF SUPPLY EXTRACT – NGC SYSTEM PERFORMANCE REPORTS 2002/03 & 2001/02

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1. INTRODUCTION

With reference to Ofgem's preliminary findings, in its Report of 30 September 2003 into the "Recent Electricity Transmission Faults Affecting South London and East Birmingham", the Consultants concur with the observation that there were certain similarities between both events. The concurrence follows a review of NGC's own investigation reports by Ofgem and the Consultants and it follows the Consultant's independent investigative work, on behalf of Ofgem. The incident similarities stem from the following facts.

- Both incidents were caused by incorrect operations of relatively new protection equipment
- Both incidents were triggered by emergency switching operations to deal with real or apparent network problems
- Both the switching operations should have been sustainable.
- Both incidents occurred while the system was under planned outage conditions, to accommodate system upgrades
- Both incidents occurred when a circuit or item of plant was subjected to increased load current, but well within its intended loadability (see Section 4.8.1 for definition)
- Both incorrect protection operations were due to the protection systems having been commissioned with undetected defects present.
- Both the protection system defects restricted circuit/plant loadability to less than intended and acceptable levels

This investigative report relates to Part-1 of the Consultancy services that were solicited by Ofgem, to support its investigations ✂. Part-1 relates to network protection as follows, since the cause of each blackout was the incorrect operation of protection:

> *Review and critical evaluation of the approach, systems, processes, and management techniques adopted by NGC for selecting and commissioning protection equipment and deriving and implementing the associated protection settings.*

The Consultants' initial investigation was based on information provided by NGC in response to requests through written questions and through two meetings that took place at Wimbledon and Hams Hall Substations. A period of correspondence discussion and clarification then followed, via Ofgem, in advance of this final investigation report being completed.

2. OVERVIEW OF INCIDENTS AND FOCUS OF INVESTIGATION

2.1 Overview of London Incident

The South London Blackout was caused by the incorrect operation of the "System Back-Up Overcurrent" protection for the New Cross 275 kV circuit number 2 from Wimbledon, after the load current on the circuit increased, following emergency network switching operations, to disconnect plant with an apparent problem at Hurst substation. The increased load current was well within the expected capability of the circuit and it should not have tripped.

The protection relay that initiated tripping was a conventional electronic unit, of type reference MCGG42. The relay actually operated correctly, but the incorrect protection system operation occurred because its primary operating current threshold was 5 times lower than it should have been. This was due to the fact that a relay with secondary current inputs rated at 1 Amp had been installed in error, during refurbishment work in May 2001, rather than a relay with the required 5 Amp rated inputs.

The relay rating error should have been detected during standard commissioning tests and procedures laid down by NGC, but it was not. The result was that the protection system was commissioned with a latent defect that remained hidden for over 2 years, until the system emergency that arose on 28 August 2003. The latent protection system defect prevented the Wimbledon to New Cross 2 circuit from being used to its full capability during a transmission system emergency.

2.2 Overview of Birmingham Incident

The East Birmingham Blackout was caused by the incorrect operation of the "Interlocked Overcurrent" protection [scheme] for the 132 kV side of the new 400 kV/132 kV step-down transformer SGT8 at Hams Hall. The incorrect protection system operation occurred when the load current on SGT8 increased, following an emergency network switching operation to unload the parallel transformer SGT6. This was to urgently deal with a serious secondary system problem that had been discovered for SGT6, some hours after it had been re-commissioned, following some weeks of substation modification work. The increased load current was well within the expected capability of SGT8 and it should not have tripped.

The protection relay that initiated tripping was a multi-function, numerical relay, of type reference KCGG142. The relay actually operated correctly, but the incorrect protection system operation occurred because non-interlocked protection functions had been unintentionally left enabled within the multifunction relay, due to errors and omissions in the settings that had been prescribed for the relay. A contributory factor was that non-interlocked overcurrent and earth fault protection had been provided as part of the contractor's protection scheme design in addition to interlocked overcurrent protection, which was inappropriate. The non-interlocked protection was not required and it had not been requested by NGC. The non-interlocked protection functionality should have either been completely disabled, through relay configuration settings, or its parameters should have been set such that there would have been no danger of it issuing an unwanted trip during clearance of a transmission network short circuit or during a system emergency.

The setting errors and omissions for the new protection relay for SGT8 were not detected during commissioning. For the numerical, multifunction relay in question, the nature of the errors and omissions was such that they would not necessarily have been detected, even if the standard NGC commissioning tests and procedures had been fully applied. The result was that the protection system was commissioned with a latent defect that remained hidden for 19 days after SGT8 had been commissioned, until the system emergency that arose on 5 September 2003. The latent protection system defect prevented the new SGT8 from being used to its full capability during an emergency.

✂ there was some non-interlocked protection functionality included within the protection scheme supplied by the Contractor, since the NGC settings summary sheet (MARS sheet) that the Engineer had prepared for the multi-function KCGG142 protection relay, had indicated that the non-interlocked overcurrent protection functionality of the protection was not to be used. However, there was an omission to detail how the unwanted protection should have been put out of service and some of the relay configuration settings that had been prescribed were erroneous, although they were in line with suggested configuration setting indications on the scheme diagram that had been supplied by the Contractor, which were inappropriate for the NGC application.

Unlike the Wimbledon defect, the Hams Hall defect was of a type (non-delayed tripping) that would have been revealed within days or weeks, rather than years – possibly without causing any loss of supply. This would have been during full loading of SGT8 or during clearance a local system short circuit. In fact, the Consultants noted that the defect came very close to being revealed during SGT8 loading at around noon on 28 August 2003, when any unwanted tripping of SGT8 would probably not have caused any loss of supply. It was the fact that the SGT8 defect was revealed during a system emergency involving another transformer at the same substation, that the unwanted tripping resulted in the loss of supply.

2.3 Focus of Investigation

It is inevitable that errors and omissions can be made by any party involved in the specification, engineering, installation, setting and commissioning of protection systems for power networks. ✂ In recognition of this fact and of the potentially serious consequences of such errors and omissions, it is necessary for any Transmission Network Operator (TNO) to have processes, procedures and associated supervision in place that will identify and correct any errors that have been made, before a protection system is signed off as being fit for service, at the end of the commissioning process.

Protection system commissioning processes and procedures are the most important last line of defence for highlighting and rectifying errors the that could otherwise jeopardise power system security, through protection failing to clear a network fault in the required time or through incorrect protection tripping at a moment when a circuit or item of plant is desperately needed to cope with a system emergency. Carefully-prepared, standard processes and procedures must be laid down by system operators for protection commissioning. In order that they will be effective, they must be rigorously implemented and adhered to by both the system operator's staff and by contractors involved with the delivery of protection systems. Thus, the proper management of protection commissioning activities is crucial.

The focus of this Volume of the investigation report was to determine the reasons why two protection system defects had not been identified during commissioning before they caused wide-area power failures.

Since the unwanted protection operations on 28 August in London and on 5 September in Birmingham were evidently incorrect, there must either have been a ✂ lapse in the application of NGC's established processes, procedures, or associated management for the delivery of new protection systems, or they must have had some ✂ flaw or inadequacy. In the event of any flaw or inadequacy it was important to establish whether this had always been the case or whether the situation had arisen as a result of equipment technology changes, or any changes in the way in which established and necessary processes, procedures or supervision are being applied.

The Consultants have reviewed NGC's established processes and procedures to facilitate the investigation of how they may have failed at Wimbledon and Hams Hall.

3. BACKGROUND

3.1 Background to protection system commissioning requirements

To assist with understanding the issues discussed in this Chapter of the Consultants' report, Figure 1 provides an overview of a single protection system. A protection system is most commonly applied to ensure rapid clearance of a faulted feeder or item of plant from the power system, or to prevent the feeder or plant from incurring damage due to sustained abnormal operation of the power system or due to the failure of other equipment to clear a fault on another part of the power system.

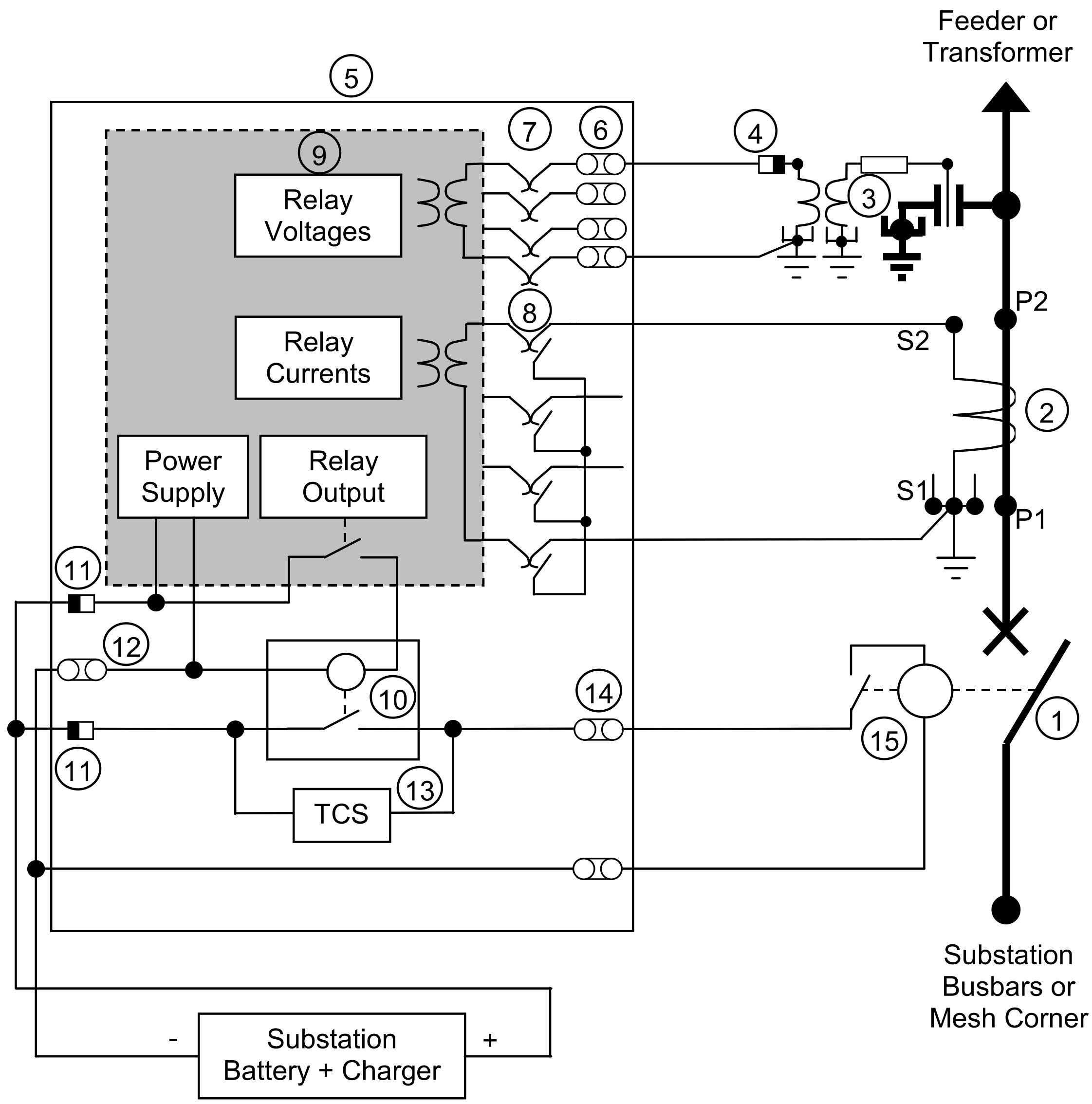

Figure 1 – Illustration of a Typical Transmission Circuit Protection System

Legend for Figure 1:

1. Transmission Circuit Breaker (per phase) 2. Phase Current Transformer (per phase) 3. Voltage Transformer (per phase) 4. Voltage Transformer Secondary Fuse or MCB (per phase) 5. Protection Scheme Relay Panel 6. Voltage Transformer Isolation Links for Protection scheme (per phase, for safety) 7. Secondary Injection Test facilities for Voltage (per phase)	8. Secondary Injection Test facilities for Current (with automatic CT shorting) 9. Group of Single Function Protection Relays or Multi-Function Relay(s) 10. Protection Scheme Tripping Relay 11. Fuses or MCB's for DC Protection Auxiliary Supply or CB Tripping Supply 12. DC Auxiliary Supply Links 13. Trip Circuit Supervision (for alarm purposes) 14. Trip Isolation Links (or test purposes) 15. Circuit Breaker Trip Coil (with CB auxiliary cut-off contact)

With reference to Figure 1, the protection relays that form part of a protection system are engineered as a protection scheme that is located in a relay panel and they monitor the primary circuit currents and/or voltages that are derived from Current Transformers and Voltage Transformers. The protection relays are securely powered from the substation Battery/Charger and they also initiate Circuit Breaker tripping using the substation battery.

For EHV transmission plant and circuits (operated at 400 kV or 275 kV in the UK), it is now policy for two fully redundant main protection systems to be provided. The redundancy extends to CT secondary windings, VT windings or secondary circuits, protection relay schemes, DC auxiliary supplies and to circuit breaker trip circuits and trip coils. A Circuit Breaker is part of a protection system, but it is not economically justifiable to provide Circuit Breaker redundancy. At EHV,"Circuit Breaker Fail" protection is provided, in lieu of breaker redundancy, to rapidly detect any failure of a Circuit Breaker to trip, when commanded to do so by protection and then to initiate tripping of other circuit breakers to clear the detected fault.

NGC circuits may also be provided with time-delayed "System Back-Up" protection, in addition to redundant main protection. This is in order to clear a sustained fault condition or a severe abnormality that might cause damage to the circuit or plant. Since back-up protection can operate for faults outside the protected circuit, its sensitivity and time settings must be carefully set to prevent unwanted tripping during normal clearance of faults outside the protected circuit or during short-term power system disturbances, such as tolerable temporary overload conditions. Greater knowledge and experience is typically required to set back-up protection than to set main protection, unless standard settings are defined by a network operator.

It can be seen from Figure 1 that a number of key components, from different factories and often from different manufacturers, are brought together within a substation to form a protection scheme. Thorough on-site commissioning tests are required to establish that all the components of the protection scheme are properly interfaced and integrated into a complete system that will perform as intended by the system designers and according to approved settings, which have been properly applied.

3.2 Changes in protection and control system technology

3.2.1 Technology developments during the last decade

Within the last decade, protection schemes offered by the major manufacturers for transmission circuits, such as feeders and transformers, have moved away from suites of single-function electromechanical protection relays, or limited-function first-generation electronic relays, to solutions based on modern, multi-function, numerical, protection units.

Multi-function protection units offer many technical and economic advantages. There are significant capital cost savings to be made in terms of the reduced number of units required to create an overall protection scheme and in terms of the significant reduction in the space required to accommodate protection equipment. Unlike the previous generation electromechanical or electronic relay designs, the numerical nature of modern protection units also offers a high level of continuous self-monitoring and consistent performance over many years of operation, due to the insignificant effects of component ageing in this respect. For this reason, numerical protection units also offer potentially reduced lifetime costs, since periodic tests can be less frequent and since they can be reduced to functional tests, rather than detailed performance tests.

A modern numerical protection unit, which monitors the currents flowing in a primary circuit and maybe the primary system voltages as well, is able to offer additional non-protection functionality. This includes facilities such as instrumentation, whereby a unit can display the current flowing in the protected circuit or transformer and possibly the system voltage, together with derived measurements, such as the level of power flow. They have the potential to replace traditionally used instrumentation transducers. They can also provide time-tagged recording of events, such as: operation of any protection function; a summary of the current levels and maybe voltage levels seen by the unit at the time of any protection operation; a record of current waveforms and maybe voltage waveforms during any power system disturbance. Such information can be of great additional assistance to a network operator when conducting post-fault equipment performance studies or incident investigations.

A further advantage of numerical protection units is that they can be networked, via serial communications links and integrated within a digital Substation Control System (SCS). In this sense, they can act as Intelligent Electronic Devices (IED's) in the field, as well as protection units, which can be remotely interrogated, so that any on-line monitoring information or any records made by the devices can be remotely accessed.

3.2.2 New technology developments adopted by NGC

With reference to NGC Technical Specification NGTS 2.24 of March 2000, the National Grid strategy for Substation Information Control and Protection (now NICAP) has required equipment manufacturers and suppliers, over the last 2-3 years, to develop standard bay solutions for NGC that allow the integration of substation protection and control functions. Protection and local automation systems have always initiated automatic operation of primary switching equipment (Circuit Breakers or Disconnect Switches) for the clearance and automatic management of transmission system faults (typically short-circuits). The non-automatic control systems of substation switching equipment, to facilitate remote operator control etc. had traditionally been independent systems. With reference to NGC Transmission Plant Specification TPS 2.24.1 of January 2003, the existing NGC light current (secondary system) asset replacement policy for substations is for the application of standard solutions that provide integrated protection, control and information functions, in order to "achieve procurement and engineering economies".

In consideration of the policies of other major Transmission Network Operators worldwide, especially in "developed countries", the progression of NGC towards substation secondary system integration is considered to be in accordance with best international practice. It is also in step with developments in protection, control, monitoring and serial communications equipment offered by the major manufacturers and some of the latest technology equipment and systems have been "Type-Approved" (now "Type Registered") by NGC for use on its electricity transmission network.

3.2.3 Some drawbacks of protection technology developments

As well as the many technical and economic benefits offered by modern, multi-function, numerical protection units, which have already been outlined, there are some notable disadvantages that are being increasingly recognised and highlighted internationally, by protection specialists, as potentially major problems (e.g. within CIGRÉ[1] Study Committee B5 for Protection and Automation). Where such problems are not acknowledged and properly managed, they can have a negative impact on the performance of protection systems, in terms of increased failures of protection to operate when required to do so and in terms of increased incorrect operations of protection when not required to do so. The problems stem from a movement by equipment manufacturers away from the "Keep it Simple" approach, which they had previously practised.

Driven by the capabilities of modern numerical protection technology, the global demands of customers, falling unit prices and strong competition, the various protection equipment manufacturers now offer numerical protection units for a global market, which are packed with multiple protection functions, many non-protection functions, many data communications options and multiple hardware rating/configuration options.

With past electromechanical and the 1st generation electronic protection relay designs (see illustrative examples in Figure 2 and Figure 3 respectively), the available area of the relay front plate imposed a tight limit on the number of protection functions that could be offered - simply because each function required discrete, physical setting facilities (switches, plugs, links, knobs etc.). In contrast, a modern numerical relay can be set using an LCD display and keypad and a settings menu. By way of illustration, Figure 4 and Figure 5 are views of two of a number of types of numerical multi-function back-up overcurrent relays that are now used by NGC.

The relay type shown in Figure 4 had originally been proposed for use at Wimbledon, at the Design Intent Document (DID) stage, but relay types similar to that shown in Figure 3 were ultimately applied at Wimbledon for System Back-Up Overcurrent protection. The relay type shown in Figure 5 was the type that issued the unwanted trip of SGT8 at Hams Hall and Figure 6 explains its user interface functions.

In consideration of relative complexity, the single phase electromechanical overcurrent relay depicted in Figure 2 might look complicated, but it only has two user settings: (i) a current threshold setting; (ii) a time curve multiplier setting. It has a single operating time characteristic curve where the tripping time is dependent on the level of the applied current. Typically, three of these units would have been applied to provide back-up overcurrent and earth fault protection for a transmission circuit. For the type of relay depicted in Figure 2, the settings are clearly visible from the front of the relay and the existence of the relay functions within the protection scheme would have been clear by the presence of the relays on the relay panel, by the visibility of their contents and by referring to the protection AC and DC scheme wiring diagrams.

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[1] International Council on Large Electric Systems
- Conseil International des Grands Réseaux Électriques

Figure 2 – Example of a Single-Phase Electromechanical Back-Up Overcurrent Relay

The relay depicted in Figure 3 is a 1st generation, electronic, three-phase back-up overcurrent relay. In addition to having main element pick-up current and operating time multiplier settings for each phase, this relay type also has four optional operating time characteristic curves that can be selected by switches and there are additional instantaneous overcurrent elements available with independent current pick-up settings. Although the number of settings for this relay are greater than those for the simple single-phase electromechanical relay depicted in Figure 2, the available and applied relay functions and settings are still clearly visible from the relay front plate and by inspection of the protection scheme AC and DC scheme wiring diagrams.

Figure 3 – Type of Electronic Back-Up Overcurrent Relay that Tripped at Wimbledon

Whilst the relay types depicted in Figure 4 and Figure 5 might appear to be simple, with each having just four or five user interface push buttons, three LED status indicators and a liquid crystal display, their appearance is misleading. Each of these relay types actually provides a wide range of protection elements, non-protection functions and scheme logic functions, with many settings and options to select. Theoretically, it is not even essential for a modern protection unit to have an integral user interface if it can be set externally, through a serial communications port, using a manufacturer’s software settings tool running on a laptop PC.

One result of the technology change from conventional electromechanical and electronic relays to numerical relay products, with serial communications, has been a proliferation of protection unit settings, by factors of more than 100 for main protection systems. The user-setting list/file for the type of back-up protection relay depicted in Figure 4 is 90 lines in length and some settings can have different values in up to 8 selectable alternative setting groups. The setting list/file for the relay depicted in Figure 5 is 93 lines in length and some settings can have different values in 2 selectable setting groups. Not all settings for these relays will affect the dependability and security of the protection, but many of them will. It is also not obvious from the front of the relay or from the protection scheme AC and DC schematic diagrams which optional protection functions within such numerical relays may have been enabled and how they have been set. There is also an increased risk of incorrect settings being applied accidentally or through lack of understanding of their significance.

Figure 4 – Type of Numerical Back-Up Relay Originally Proposed for Wimbledon

Figure 5 – Type of Numerical Back-Up Overcurrent Relay that Tripped at Hams Hall

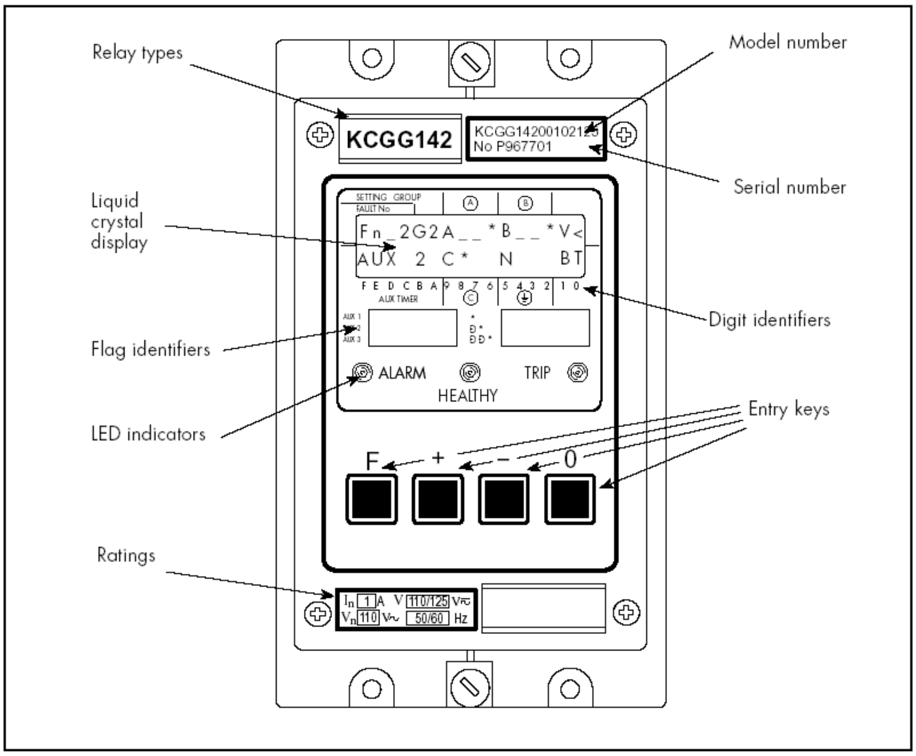


Figure 6 – Explanation of User Interface Functions for KCGG142 Numerical Relay

Having reviewed a number of protection incidents related to power failures, the experience of the Consultants affirms that one of the greatest risks with determining or applying settings to a modern numerical protection unit is that some available protection function, that is not actually required, could be accidentally left enabled, with its default settings applied. Testing and commissioning procedures that were based on simply checking the correct operation and settings of intended protection functions, which were clearly visible for previous generation protection schemes, were adequate for such schemes. When dealing with modern protection schemes, it is becoming clear that an additional requirement for testing and commissioning is to prove that no rogue protection function is enabled and that no hardware configuration error has been made – especially any error that would interfere with the required operation of the protected transmission circuit or plant under normal and emergency loading conditions. The established procedures of many contractors and network operators have yet come to terms with this issue.

For the commissioning of modern protection schemes, involving multi-function numerical relays, the Consultants advocate the application of some form of circuit loadability test, based purely on declared operational requirements for a transmission circuit and taking into account only the ratios of the current transformers and voltage transformers and not simply seeking to prove that intended protection functions operate in accordance with the prescription of the scheme design engineers or the settings engineers, who can make mistakes.

4. REVIEW OF NGC STANDARD PROCESSES AND PROCEDURES

4.1 General

The two blackout incidents under review by the Consultants both involved incorrect operations of protection that were due to latent protection defects that had not been detected during the commissioning tests and procedures that were applied. In both cases, there were incorrect effective settings of protection systems; either through the application of an incorrectly rated protection relay or through the incorrect configuration and setting of a protection relay. In order to establish how the processes and procedures may have failed or whether they might be inadequate in some respect, it was first necessary to review those that NGC already has in place for protection scheme delivery and how NGC understands them.

The review of NGC's processes and procedures that is summarised in the following sub-sections has been largely based on NGC's written responses to a range of formal questions posed by the Consultants and by reference to various NGC Transmission Procedure (TP) documents. Some of NGC's responses have been included or paraphrased, where appropriate. ✂ The responses have been used purely as benchmarks, against which the actual asset replacement work at Wimbledon and Hams Hall substations was assessed.

4.2 Changes in NGC protection scheme delivery

✂ NGC's methods for soliciting tenders, setting up contracts and dealing with Contractors have changed in recent years. With reference to NGC's response to Consultants' question PBP020 (see APPENDIX F), regarding contract strategy, NGC stated that it previously had its own internal Design Branch within its Project Management Division. This was responsible for developing and designing protection schemes for installation by external installation contracting organisations. Over the last five years, however, a revised contract strategy has been developed and progressively implemented, in conjunction with NGC's key suppliers. NGC stated that this has been partly in response to the changing technology of protection devices, as outlined in Section 3.2.1 of this report, but also due to NGC's increasing capital investment programme. NGC identified that it needed to change its methodology for the delivery of its construction projects in a controlled manner.

Increasingly, NGC has passed the detailed design responsibility for protection system engineering to its main suppliers, but NGC stated that it has retained the responsibility for specifying and determining compliance with its standards and specifications, as detailed in the National Grid Technical Specification (NGTS) suite of documents and their requirement for Contractors to submit Design Intent Documents for each contract.

To illustrate the nature of the contract covering protection systems for work at Hams Hall (Lea Marston) 132 kV Substation, which was at the heart of the Birmingham blackout, and the responsibilities that were devolved to the Contractor, some scanned extracts from the general sections of the protection specification are provided in Figure 7. This tender document was issued in March 2000. Tender documents are now prepared in line with the guidance provided by an NGC Tender Manual.

8.1 Protection – General Requirements.

This section details the protection, control and telecommunications aspects for new works at Hams Hall 'C' 132kV (to be renamed Lea Marston 132kV) and the interface requirements for associated work at affected remote end sites. The NGC circuits consist of four Supergrid 132kV bays, two 132kV Bus Coupler bays and one 132kV Bus Section bay. There are ten REC 132kV circuits, two circuits to East Midlands Electricity and eight circuits to GPU (formally Midlands Electricity).

The scope of work shall include the supply and installation of all protection, control and telecommunication equipment as specified below, including all necessary components, materials, relay panels/cubicles, ducting, multicores, engineering, supply of drawings, modifications to associated dependent schemes, testing and commissioning.

All primary plant and equipment shall be fully protected to NGC standards. All protection systems shall be fully compliant with the requirements of NGTS 2.6 and associated level 3 specifications and shall be NGC Type Registered. Where specific REC requirements are applicable either at Hams Hall 132kV or the remote ends these shall be stated separately.

The settings to be applied to protection systems shall be specified by the contractor and calculations shall be submitted to NGC for assessment and agreement, ***not less than six months*** prior to the commencement of any associated testing or commissioning activities on site. This shall include a protection setting report for the busbar zone protection.

8.2 Application to Contract

Although every attempt has been made to describe the protection and control requirements, it is ultimately the responsibility of the contractor to identify the exact requirements to deliver a fully functional scheme, ensuring the equipment offered complies with all the relevant NGTSs and other NGC standards.

Figure 7 – Extract from Tender Document C/XT022 for Hams Hall 132kV Work

4.3 NGC formal processes, procedures and standard documents

4.3.1 Documents

With reference to Consultants' question PBP001, NGC stated that it has developed a range of documents that set out the many technical, commercial and project management procedures and requirements for transmission scheme development and delivery. A number of documents, especially Transmission Procedure (TP) documents, have been prepared within the last 5 years to address the new ways in which NGC delivers transmission schemes and the new ways in which it interfaces with Contractors. The Consultants are aware that a number of experienced NGC engineers were charged with preparing such documents ✂ etc. NGC summarised various aspects of scheme delivery and related documents as follows:

- Overall Process

  (a) Scheme Development and Delivery (TP146, December 2002)

- Design

    (a) Scheme Design Specifications defining the power system electrical design (Level 2 of NGC Tender Manual)

    Substation Design Specification (includes protection & control systems)

    Civil Design Specification

    Overhead Line (OHL) Design Specification

    Cable Design Specification

    (b) Design intent requirements (Process detailed in Level 1 of NGC Tender Manual and TP146)

    (c) Design Intent Document (DID) pro forma (Appendix to Level 1 of NGC Tender Manual). The DID is a document prepared by the Contractor, and agreed with NGC Construction, to confirm that the installation design and its method of construction is compliant with the contract specification

    (d) National Grid Technical Specifications (NGTS's, as dictated by Engineering Policy Statement EPS 3.0 of May 1999)

- Equipment Approval

    (a) Type Registration (replaced the old Type Approval process in 1998 and is referred to in Engineering Policy Statement EPS 3.0 of May 1999)

- Manufacture and Installation

    (a) Quality Assurance Plan (detailed in Level 1 of NGC Tender Manual)

- Settings

    (a) Protection and Control Relay Settings (TP107, May 2003). There was a major rewrite in 2003 to reflect the new NGC organisation and Post Delivery Support Agreements with suppliers, procedures that were added where suppliers perform setting calculations and the inclusion of numerical relays

- Integration and Commissioning

    (a) Equipment Commissioning and Decommissioning (TP106, October 2002)

    (b) Site Commissioning Test sheets (SCT's for commissioning individual items of equipment)

    (c) Commissioning Handbook (CH Chapters for commissioning systems)

(d) Co-ordination of Installation during Project Delivery (TP153, November 2000). This document details co-ordination of activities on multi-site projects.

(e) Site Responsibility Schedules (TP136, January 1999). This document defines responsibilities on jointly owned sites.

4.3.2 Processes

With reference to Consultants' question PBP006, the process for the development and delivery of protection designs associated with New Connections, Infrastructure and Asset Replacement schemes is defined in National Grid's Transmission Procedure TP146. The document also covers the requirements associated with trials of new technology.

NGC stated the high-level power system electrical design and the protection design requirements for a scheme are initiated through this procedure and they result in the preparation of a Scheme Design Specification (SDS). This specification includes a single line diagram of the HV equipment and associated nomenclature specification, including a schedule of the generic protection requirements in block outline form such as unit, non unit, backup protection etc, depending on the circuit configuration.

The more detailed aspects of a scheme to be delivered are set out in the associated Substation, Civil, Overhead Line (OHL) and Cable design specifications, as required. These specifications, along with the high level Scheme Design Specification, form the basis of the technical requirements set out in the tender manual.

The tender process requires each contractor to respond and confirm the equipment and design that is being offered.

Within approximately three months of contract release, the successful Contractor is then required to submit a Design Intent Document (DID). The DID defines how the design specification is translated into the detailed working design, its installation and commissioning. The DID is reviewed by the National Grid Project Manager to confirm that the proposed protection design and method of construction is compliant with the contract specification.

All protection equipment and system designs for specific NGC scheme applications must be in accordance with relevant NGTS's and must be covered by the equipment Type Registration process. Any deviation from this requirement, e.g. associated with the introduction of new protection relays, must be sanctioned by NGC's Asset Strategy Manager, who will define the required specification.

Once acceptance of the DID has been notified by NGC, the detailed protection design process is allowed to commence. Any deviations to the proposed design, including the protection equipment, are managed through the Project Design Review process.

The West Midlands and London schemes were developed in the late 1990's - before the TP146 process had been established. The high level design was set out in Transmission

Reinforcement Instructions (TRI) and the then NGC's Project Management Division prepared a detailed technical tender enquiry document, which reflected the TRI requirements and other technical requirements defined in NGTS's, Transmission Plant Specifications, IEC standards etc.

4.4 Procurement of protection and control equipment and systems

With reference to Consultants' question PBP005, NGC stated that it now operates a Type Registration system for all plant and equipment to be connected to its system. This replaced the old product Type Approval system in 1998.

With the old system, a Protection Approval panel would have been established for each major item of protection equipment that NGC might be interested in deploying. Such a Panel would demand much descriptive and type test documentation from the product manufacturer before granting approval and it would be actively involved with witnessing selected type tests at the manufacturer's factory. This system was eventually abandoned by NGC ✂.

NGC's stated purpose for the Type Registration system is to ensure compliance with NGC's technical standards. This is a risk-managed process described in the documents NGTS 1 and Engineering Policy Statement 3.0. It is a requirement of the conditions for all contracts that suppliers only offer and install plant and equipment that satisfies this process.

Type Registration requires self-certification of compliance with the appropriate National Grid Technical Specifications by the supplier for the plant and equipment being offered. This submission is audited and verified by NGC to ensure all Test Results, Test Evidence, Technical data and Supporting Documentation are complete. One pertinent example of supporting documentation that must be provided for a Type Registered product is a Site Commissioning Test (SCT) document, to be used as a pro-forma for performing on-site commissioning tests and for recording test results.

4.5 Calculation of protection settings

With reference to Consultants' question PBP007, NGC stated that Transmission Procedure TP107 defines the management process for the production, application, dissemination and recording of settings for protection and control equipment owned by NGC.

Settings engineers are nominated by the Construction Manager to carry out the necessary calculations and setting process. Relay settings are stored in NGC's Multi Access Relay Settings (MARS) database.

Settings engineers are authorised after satisfactory completion of a period of on-the-job training, under the supervision of an authorised settings engineer, followed by a technical interview covering relevant topics areas.

With reference to the scanned extract from section 3.2 of TP107 given in Figure 8, the Consultant's understanding is that there are two categories of Settings Engineer (NGC or Supplier). The Settings Engineer (Supplier) may be an authorised Settings Engineer either within the employment of the supplier or a sub-contracted consultant – sometimes an ex-

NGC employee. The process by which settings should be determined by the Supplier or NGC and then handed to NGC for review are detailed in Section 4.1 of TP107. Section 6.1 confirms that it is an NGC engineer who is responsible for entering settings into the definitive "MARS" summary sheet for any protection relay. It is clear that the service settings to be applied to a relay should be derived only from the MARS sheet and it is clear from Section 3.3 of TP107 that the NGC Initiating Engineer would be accountable for all settings provided by any Settings Engineer (Supplier).

3.2 Settings Engineer

Settings Engineer (NGC)
An engineer who has been nominated by the Construction Manager to carry out the calculations and setting processes defined in this procedure.

Settings Engineer (Supplier)
An engineer who has been nominated by a Supplier to carry out the calculations and setting processes in accordance with the contractual arrangements.

3.3 Initiating Engineer

A nominated Settings Engineer (NGC) responsible for providing the interface with the Settings Engineer (Supplier). The Initiating Engineer will retain accountability (i.e. ultimate responsibility) for all settings provided by a Supplier, and will provide the signature on the MARS settings sheet.

The Initiating Engineer, in discharging his accountability, will use professional judgement to decide whether a full or rudimentary check will be carried out on a Supplier's setting. This will be determined by setting complexity, uniqueness and Supplier performance history.

4.1 Determination and Application of Settings

4.1.1 Protection and control setting calculations must only be carried out by a Settings Engineer (NGC or Supplier) in accordance with relay setting policies and system data defined in Appendix B.

4.1.2 The Settings Engineer (NGC or Supplier) will record details of all pertinent relays on Relay Settings Data Sheets (Appendix C) prior to calculation commencing. The requirements for completing a Relay Settings Data Sheet are defined in Appendix D.

4.1.3 The Settings Engineer (NGC or Supplier) shall acquire test data from the party contracted to carry out the tests or other sources where such data is necessary to determine or verify the settings required.

4.1.4 The Settings Engineer (NGC or Supplier) shall calculate or determine all required settings and formally record all calculations, a copy of which must be filed in Construction's relay settings calculation files. The setting shall be entered into MARS by authorised personnel as defined in section 6.1. A copy of each setting sheet bearing the signature of the Settings Engineer (NGC) who calculated the setting, or the Initiating Engineer, shall be sent to the Commissioning Engineer. The format of the settings sheet is defined in Appendix F with the requirements for completion in Appendix G. Where the calculation and setting process is by a Supplier, the Initiating Engineer must provide the 'issued by' signature on the settings sheet.

6 SETTINGS RECORD DATABASE (MARS)

6.1 The relay settings determined in accordance with this procedure are held on the MARS database. It is username controlled so that only authorised users can obtain access. Those authorised to enter settings into MARS are limited to the Settings Engineers (NGC), the Settings Administrators, and any trained individual nominated by the Responsible Manager defined in Appendix K

6.2 For numerical non-integrated protection relays, the setting configuration files shall be kept in a password-protected directory on the National Grid Network or managed by a third party where a contractual agreement is in place. Such files will be cross-referenced to appropriate MARS setting sheet.

Figure 8 – Extracts from TP107 for Protection and Control Relay Settings

4.6 Commissioning of protection and control equipment

4.6.1 General requirements and commissioning panel

With reference to Consultants' question PBP007, NGC stated that TP106 sets out the standard approach adopted within NGC for the Commissioning and Decommissioning of assets employed on the HV transmission network, covered by its Transmission Licence. The scope of TP106 defines the framework of requirements that apply to the majority of projects, the exception being those projects with a high degree of civil engineering activity. The procedure stipulates the Commissioning Panel Model format for directing the commissioning process. This model is utilised at the first meeting of the Commissioning Panel, thereby forming the basis of subsequent meetings, so that all essential topics will covered. The responsibility for the implementation of the procedure rests with the Commissioning Panel, which is either a formally convened body of individuals within NGC, or sub-contractors to NGC, with the appropriate skills and qualifications to ensure that the commissioning activities are managed safely and effectively.

The principal objectives of the Commissioning Panel are as follows:

- To call and approve the Commissioning Programme
- To ensure commissioning is undertaken by personnel with the appropriate qualifications and experience
- To manage and co-ordinate commissioning interfaces
- To establish Commissioning Working Parties
- To determine the extent of commissioning witnessing and hold points necessary to facilitate commissioning
- To ensure compliance at all times with NGC Safety Rules
- To ensure the delivery of operational data and technical information
- To confirm the acceptability of the contractors test equipment
- To ensure that commissioning is progressed in accordance with appropriate certificates
- To ensure the satisfactory completion of all documentation.

4.6.2 Authorisation of commissioning engineers

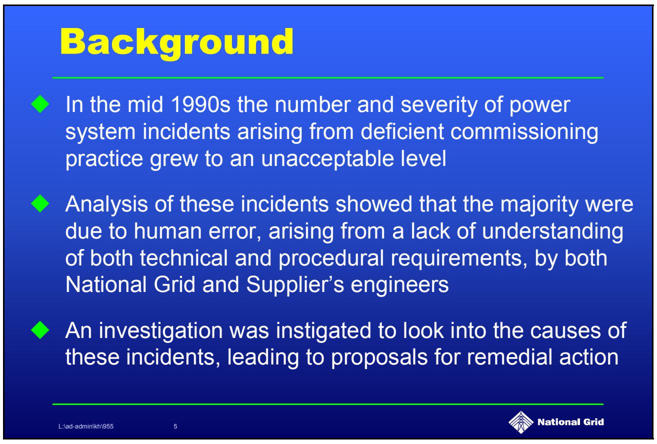
NGC stated that Transmission Procedure TP141 details a structured programme of training and assessment for all engineers with formal commissioning responsibilities. TP141 details the equipment experience, technical knowledge and management capabilities required to discharge these duties in respect of the following:

- Protection schemes (to variable levels)
- Synchronising schemes
- Interlocking schemes
- Switchgear control schemes
- Automatic switching schemes
- On-load testing
- Operational procedures
- Earthing procedures
- Transformer systems
- Transformer commissioning
- HV cable systems
- Mesh substation DAR
- Fault recorder charts

With reference to Consultants' questions PBP003 and PBP004, NGC stated that its engineers with formal commissioning responsibilities are authorised at two levels – Basic and Advanced. Basic authorisation enables an engineer to undertake commissioning on asset replacement projects, whilst Advanced authorisation relates to any project. For both levels there are formally tutored and assessed modules, each comprised of both technical and managerial requirements.

In recognition of NGC's new contract strategy (refer to Section 4.2) a presentation was made to NGC's major suppliers on 6 December 2002, concerning Commissioning Authorisation. The presentation notes have been reviewed by the Consultants. The purpose of the presentation was to explain to key suppliers why NGC had undertaken the authorisation of its commissioning staff and how suppliers staff might become involved. With reference to extracts from the presentation given in Figure 9, NGC had noted that, from the mid-90's, the "number and severity of power system incidents arising from deficient commissioning practice grew to an unacceptable level" and that "analysis of those incidents showed that the majority were due to human error, arising from a lack of understanding of both technical and procedural requirements, by both National Grid and Supplier's engineers".

In January 2003, agreement was reached with all major suppliers to extend NGC's Commissioning Authorisation process to include the supplier's commissioning engineers. To this end, a series of formal authorisation courses, with compulsory testing and certification, were provided for suppliers by NGC in both April and June 2003. Further courses were planned for November 2003 and February 2004. To optimise on timescales and resources, suppliers will initially be authorised at the Advanced level and the NGC tutored course documentation was modified to facilitate this requirement. By April 2004, NGC's commissioning procedure (TP106) will mandate that only those suppliers' lead commissioning engineers and test engineers who are in possession of an authorisation certificate will be allowed to undertake commissioning responsibilities on the NGC system. From autumn 2004 onwards, suppliers will attend the same courses as NGC engineers and from that point, they will be classified as Basic or Advanced.



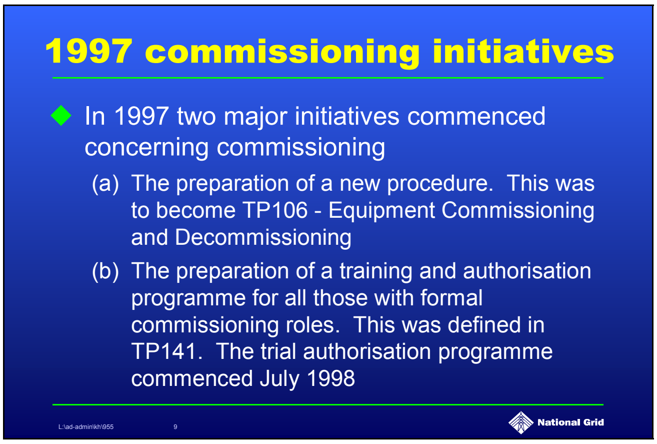


Figure 9 – Extracts from NGC Presentation to Major Suppliers 06/12/02

4.7 Supervision of contractors

With reference to NGC Technical procedure TP106, for Equipment commissioning and Decommissioning, Section 2.12 (see Figure 20, Section 6.6.2) states that Stage-1 off-load inspections and Commissioning Tests may be carried out by a Contractor without being witnessed by National Grid Personnel, but at the discretion of the Commissioning Panel. Section 2.13 states that Stage-2 tests, which would include any on-load commissioning tests for protection systems, must be directed by a Commissioning Engineer (from NGC). The NGC Commissioning Engineer reports to the appointed NGC Commissioning Officer, who reports to the Commissioning Panel Chairman. The specified duties of the Commissioning Officer are set out in Section 3.5 of TP106 and a scanned copy of the Section is provided in Figure 10.

3.5 Commissioning Officer

The Commissioning Officer is an engineer from Construction authorised for this purpose, whose prime responsibilities are:

(a) to confirm that the **Equipment** to be commissioned accords with the design specification defined in the contract, or otherwise confirm the acceptability of alternative **Equipment**

(b) to confirm the acceptability of design changes which occur during commissioning

(c) to progress and ensure the availability of all Type Registration requirements to meet commissioning timescales (eg. SCT sheets, **Equipment** data, and handbooks)

(d) to identify installations which are non-standard and to determine responsibility for test documentation preparation

(e) to progress and ensure delivery of all operational data (eg. settings, schedules, data sheets etc)

(f) to chair commissioning working parties when projects involving complex **Equipment** undergoing Type Registration require special consideration outside the Commissioning Panel

(g) to manage the contractor technical interface

Figure 10 – TP106 Definition of Commissioning Officer Responsibilities

4.8 Loadability Issues

4.8.1 Loadability and its definition

The Consultants have chosen to use the term “loadability” in discussion related to the commissioning and proving of protection functions that can impose operational limitations on plant or circuits. The chosen term is defined as follows:

> *The “Loadability” of a circuit, or item of plant, is defined as the maximum level of load current that it is able to carry before the current will be interrupted by the operation of any item of automatic protection.*

The two loss-of-supply incidents under investigation can both be attributed to latent protection defects that prevented a feeder and a transformer from being loaded to levels within their expected capability, during system emergencies, where there were other planned circuit outages due to maintenance or refurbishment work. Thus, the investigation must naturally review how NGC ensures that the required loadability of circuits is proved during protection commissioning tests and procedures.

4.8.2 Checking protection

With reference to Consultants’ question PBP010, NGC stated that the thermal rating requirements and performance of NGC primary plant is covered by the Type Registration process and Transmission Standard NGTS 1. For system security and planning standards reasons, the high voltage transmission system cannot be configured to load any new primary plant to or beyond its required rating.

NGC stated that calculations of protection settings are dependent upon a number of criteria, one of which is the plant rating. Once settings have been calculated and applied, NGC confirms that an on-load load test is undertaken. Light current protection equipment with directional facilities, or current differential protection, can be tested during the Stage-2 on-load commissioning process. A switching programme is compiled, where possible, to provide sufficient primary current to allow the correct application of these features and functions to be confirmed (this may involve switching out other circuits or altering substation running arrangements to generate sufficient load current). Where this cannot be achieved by configuration of the primary system, tests can be undertaken through temporary reconfiguration of the secondary system.

In posing question PBP010, the Consultants were seeking to establish the NGC procedures for checking that protection functions, such as Overcurrent relays or Underimpedance (Distance) relays, would not interfere with the temporary emergency loading requirements for a feeder or transformer. NGC's initial reply to the question focussed on the on-load tests that would be applied to check the correct application and setting of certain other aspects of protection, as described in the previous paragraph. Following the Consultant's definition of their "loadability" term, there followed further correspondence discussion with NGC, through Ofgem, to discuss this issue further.

The Consultants checked the Site Commissioning Test procedure SCT 20.5.3 for Overcurrent and Earth Fault protection to seek details of any formal protection load limit check/test. The only requirement is for a check to be made to confirm that the settings derived from the NGC MARS settings sheet have been correctly applied to the protection relay and that the relay pick-up is correct with those settings applied. With this approach, there is somewhat of a presumption that the Settings Engineer has not made any error. However, the MARS sheet should state the required primary operating current for the circuit under test and a diligent Commissioning Engineer, through back-calculation of the relay primary pick-up current from the CT ratio, would probably spot any settings error if the SCT is fully applied.

As part of their response to the two loss-of-supply incidents and in response to the Consultant's questions, NGC submitted a protection remedial actions report on 15 October 2003. Salient sections of that report were briefly reviewed by the Consultants, as covered in Section 10 of this Report. Through Section 63 of their supplementary report, NGC acknowledges that an additional back-calculation protection commissioning procedure should be formalised and demanded to make the proving of protection primary operating current and circuit loadability more robust.

A back-calculation procedure would certainly have enhanced the existing tests and procedures for revealing the protection system defect at Wimbledon, if they had been fully applied. However, back-calculation is only effective when applied to protection functions that are known to be enabled. For the testing of protection systems based on new multi-functional numerical relays, such as the SGT8 ILOC protection scheme relay at Hams Hall, the existing commissioning tests and procedures would not necessarily detect a loadability limitation imposed by any protection functions that are unintentionally enabled, through relay configuration setting errors, even if the tests and procedures had been adequately applied. The application of a back-calculation procedure in relation to the intended interlocked protection functionality would also not be effective with regard to any unintentionally enabled protection functions that impose a loadability restriction above the operating current of the intended protection functions.

The Consultants recommend that supplementary Feeder Loadability tests should be devised and that they should be mandatory once all the service settings have been applied to the protection systems. Such tests should prove that none of the protection systems will restrict the loadability of the feeder, up to the level of current expected by system planners and operators. More detail about this recommendation is given in Section 9.

Since issuing their report of protection remedial actions on 15 October, NGC continued with its review of commissioning procedures and it acknowledges that there will also be merits in carrying out loadability testing and they will be undertaking detailed work to assess the practicality of introducing a loadability test into their protection commissioning procedures.

The type of loadability testing being suggested by the Consultants is not yet the common practice of other TNO's worldwide and so NGC has not been outside best international practice by not specifically requiring such tests to date. However, as with NGC, other TNO's are experiencing increasing supply interruptions caused by human errors related to protection and particularly protection setting errors, where the complexity of new multifunctional relays is a contributory factor and where the errors are not being picked up by established commissioning tests and procedures.

The introduction of loadability testing would still not identify the unintentional enabling of unwanted protection functions where they do not impose a loadability restriction. This type of error might only be revealed through unwanted (indiscriminate) protection tripping during a network fault and maybe only where the unwanted protection is not set with a time delay. It is probably more serious, though, to have an unwanted trip of a circuit or plant under emergency load conditions than during fault clearance, since tripping at lower than expected load current effectively removes the spare capacity of a feeder or item of plant, when the main justification for providing the circuit was to provide spare capacity to achieve a firm supply. Thus, the proving of loadability is probably more important than proving that absolutely no unwanted protection functions are unintentionally enabled. An exception would be where a single settings error that does not affect loadability is repeated for a number of relays, such that multiple circuits or items of plant might be incorrectly tripped in response to a single short circuit fault.

Whilst the benefits of modern numerical relays surely outweigh their disadvantages, heightened concerns about some of the hazards of modern multifunction relays has prompted NGC set up a project team to work with its key suppliers to address additional "negative testing" requirements. Such testing is targeted towards actively ensuring that all unwanted protection and control functionality within multi-function numerical devices is securely disabled and that required functions are correctly configured, so that there will be no incorrect tripping under load or fault conditions. This project team has been targeted to deliver its recommendations by the end of January 2004.

4.8.3 Declaring circuit loadability after commissioning

With reference to Consultants' question PBP011, NGC stated that the loadability of any circuit is declared to Operations and Trading (O&T) in the form of a rating sheet.

The rating sheets are produced by the Condition and Capability team (within Asset Strategy) using the Critical Unit Program (CUP2). This software combines the ratings for all the individual components that comprise a circuit to produce the overall circuit rating. This includes seasonal variations in ratings and the short-term overload capability of a circuit. Once calculated CUP2 automatically posts the circuit rating sheet on to the intranet.

The production of circuit ratings is controlled by the Network Strategy procedure NSPM301. This process ensures that all the data necessary to produce the circuit rating is transferred from the suppliers, via Construction, to the Condition and Capability team 18 weeks prior to commissioning. This allows the rating sheet to be calculated sufficiently far in advance to allow O&T to perform the necessary system planning functions.

CUP2 holds the plant items associated with a particular circuit and their ratings. A rolling seven-year audit is conducted to check that the plant items associated with a circuit match those held in the Asset Management Information System (AMIS).

Following commissioning, the Commissioning Panel Chairman declares that the new equipment has been fully integrated with the main transmission system, and declares that the rating described on the circuit and plant capacity rating sheet may now be applied to the circuit for operational purposes.

It is assumed, therefore, that the Commissioning Panel and its Chairman must be satisfied that the appropriate commissioning tests and procedures have been conducted and followed, by suitable NGT and Suppliers personnel, and that there is sufficient evidence of satisfactory test results and completion.

4.9 Performance monitoring of protection and control equipment

With reference to Consultants' question PBP014, NGT stated that the performance of the protection systems on the National Grid UK electricity transmission network is monitored through the Asset Health Review process. This process is an ongoing cross functional review of issues affecting the performance and condition of all National Grid owned assets, which recommends asset management actions. These actions are addressed through the appropriate capital/revenue business process. The Asset Health Review policy is described in EPS10.0 and the Asset Health Review process is described in NSPM204. Some output data provided by NGC from this process, in relation to protection systems, is reviewed in Section 8.1 of this report.

✂ it would ✂ be expected practice for a Transmission Network Operator to maintain performance statistics as an essential reference for the planning of maintenance and asset replacement strategies. In response to Consultants' question PBP014, NGC has provided statistical information for the last 10 years, which is discussed in Section 8 of this report.

4.10 NGC protection incident investigation procedures

4.10.1 Current procedures for any investigations

With reference to Consultants' question PBP016, concerning NGC's current practices and procedures for investigating incorrect protection operations or failures to operate, NGC provided the following account of general investigation procedures only, rather than those specifically related to the investigation of protection incidents.

In the event of an incident on the transmission system, such as a failure of plant, National Grid undertakes an investigation to establish the cause of the failure and any remedial actions necessary. The procedure UK BP/SE/001 sets out the process that is followed for all investigations including incorrect protection operations and failures of protection to operate. There are three levels of investigation (high, medium and low) that can be undertaken, depending upon the severity of the event. A Responsible Manager is assigned to ensure that the incident is investigated. The Responsible Manager will be a director or senior manager for a high level investigation, supported by an investigation team. A Line Manager or Location Manager will carry out medium and low-level investigations.

Below we set out examples of Incidents and the associated level of investigation and the seniority of the responsible Manager.

High-level investigations where a Director acts as responsible manager:-

- Any fatality
- Potential to result in prosecution
- Falling conductor
- Widespread loss of supply, significant financial impact.

High-level investigation where a senior manager acts as responsible manager:-

- Falling from harness
- Significant oil spill
- Significant loss of supply, loss of generation
- Significant near miss, e.g. member of public nearly hit by flying porcelain

Medium level investigation where line or location manager acts as a responsible manager :-

- Person falling down stairs
- Minor oil spill
- Cable oil leak
- Unwanted protection operation
- Catastrophic failure of plant

Low-level investigations where line manager or location manager acts as responsible manager:-

- Road traffic accident, for example, where vehicle shunted from behind
- Diesel spill, however diesel contained on site

- Person tripping for example loose tile on substation floor

The key steps in any investigation are as follows.

- The person at the scene of the incident reports the event to the Incident desk and his line manager (normally within one hour of the incident)
- The Responsible Manager will appoint a Chairman to investigate the incident ensuring the Chairman has the necessary skills, experience and knowledge.
- The Responsible manager agrees the Terms of Reference for the investigation with the Chairman
- The Chairman then establishes a team and appoints a Technical Secretary, ensuring that all the necessary skills, experience and knowledge are represented within the team to investigate the incident.
- The team then undertakes the investigation the key elements of which are set out in Appendix 1.
- The team will then produce a report setting out the learning points, the conclusions of the investigation, and any recommendations.
- The actions from the report are assigned to the appropriate manager and captured in a central database to allow easy monitoring of progress.
- The Responsible Manager will ensure actions are discharged within the assigned timescales.

For high-level investigations, the procedure calls for a Chairman to be appointed by the Responsible Manager from a list of trained chairpersons.

This list is maintained centrally and includes information regarding the qualifications and experience of the Chairperson.

Appendix 1 of NGC's response, referred to in the bullet points above, has not been included here for brevity, but it is pertinent to highlight a couple of items in view of the comments made in Section 5 about the limited scope of the incident reports made available for this investigation:

10. Conduct interviews

11. Conclude the cause of the incident, i.e. why it happened, considering:

    (a) people skills and behaviour

    (b) process inadequacies

    (c) equipment deficiencies/limitations

4.10.2 Application of lessons learned following any investigation

With reference to Consultants' question PBP017, NGC stated that, on completion of an investigation, a number of actions would be agreed to address the issues that contributed to the incident. These actions are assigned to a manager within National Grid, together with a timescale for completion. All actions from investigations are captured in a central database to allow monitoring of progress. Reports are provided on a monthly basis to Senior Managers to ensure actions are being completed in the appropriate timescales. Actions can be wide ranging and random audits are undertaken to ensure both the appropriateness of the actions arising from the investigations and that actions are completed.

Question PBP017 followed on from question PBP016, where the details of protection incident investigation procedures were being sought, but since NGC chose to respond to PB016 in a general manner, the response to PB017 was also of a general nature.

4.10.3 Changes to investigative practices and procedures over last 5 years

With reference to Consultants' question PBP018, NGC stated that, as part of their normal quality assurance processes, all procedures are reviewed on a regular basis. The procedure that covers investigations was reviewed on 1 May 2003, as part of a Transmission procedure review programme. This review programme was initiated to ensure that the procedures reflected changes to the structure within the organisation.

The key changes to this procedure were: -

- to reflect the introduction of the incident reporting desk. This allows staff to more easily report incidents and ensures a more effective process for monitoring the actions that arise from them.
- to reflect the introduction of a central database for the reporting and monitoring of all incidents
- to reflect the three levels of investigation described in the answer to question PBP016 (see Section 4.10.1 of this report).
- update to a more user-friendly format, making use of simple flow diagrams etc. This has proved beneficial in ensuring a clear understanding by staff of the key processes.

Although NGC stated that their investigative practices have not changed significantly over the last 5 years, they consider that the updating of this procedure, together with utilising a central database to capture all incidents, have enhanced the overall practice. It was also planned that training of additional Chairpersons and Technical Secretaries would commence in November 2003.

Question PBP018 followed on from questions PBP016 and PBP017, where the details of protection incident investigation procedures were being sought. Since NGC chose to respond in a general manner, the response to PB018 was also of a general nature and so it was not possible for the Consultant's to assess how the investigation practices and procedures of protection incidents may have changed over the last 5 years.

5. REVIEW OF INCIDENT REPORTS FOR LONDON AND BIRMINGHAM

With reference to Consultants' questions PBP022 and PBP029, in which copies of internal investigation reports and remedial action reports were requested, the Consultants were provided with NGC's public domain (website) reports of 10 and 19 September 2003 concerning the London and West Midlands incidents, respectively. A copy of a later protection remedial actions report of 15 October 2003 was also provided (see APPENDIX G).

✂. In response to question PBP106 of 24 October 2004, NGC confirmed that no other reports were available at that time and no other reports have been received since.

the initial incident reports released by NGT on 10 and 19 September 2003 had been prepared in a relatively short period of time, in view of the intense public interest and concern, which was being expressed by politicians and the media. ✂ the reports were naturally targeted to a mostly non-technical audience, in order to maximise general understanding as to what had happened in each case, even though some complex issues and sequences of events had been involved. This is why the reports ✂ were different in style to NGC's previous incident investigation reports. NGC highlighted the fact that none of the reports for other prominent wide area power failures around the world in 2003 had been issued in less than several months. ✂

In subsequent correspondence with NGC via Ofgem, covering the content of available reports and the absence of further non-published reports to date, NGC stated that they had been supplying much detailed information to Ofgem's Consultants, for their detailed investigation and that they had elected not to duplicate that particular effort. NGC stressed, however, that the non-availability of additional internal reports did not mean they had not conducted any further work of their own. NGC confirmed that their published incident reports of 10 and 19 September, plus the protection remedial actions report of 15 October, were the only reports that they had completed during the investigation by Ofgem's Consultants, but that their "Review of the Management of NGC Protection Systems" is ongoing. NGC's report of 15 October has apparently undergone further significant development since it was first issued and NGC emphasised that this was not the only element of further work that is being undertaken. They wished to draw attention to the "list of actions being pursued" that was given in Section 145 of their published report of 10 September, following the London incident. The actions related to protection are picked out as follows:

- National Grid is urgently surveying all installations as a further check on the integrity of the automatic protection equipment.
- National Grid will carry out a further comprehensive investigation examining all aspects of the management of the protection systems so as to eliminate, as far as possible, the risk of incorrect installation or operation of automatic protection equipment.

✂

6. REVIEW OF LONDON INCIDENT

6.1 Background to London Incident

The protection that operated incorrectly at Wimbledon on 28 August was part of a refurbished protection scheme that was commissioned in 2001. Following an NGC Tender Enquiry for Protection Refurbishment work at various sites, a Contractor was appointed in 2000 to refurbish the protection and control systems for the 275 kV Mesh Corners 1 and 3 at Wimbledon Substation. The existing primary plant circuit breakers, voltage transformers and current transformers were to be retained. The work included refurbishment of the Main and Back-Up protection systems for the Beddington 1 and New Cross 1 Feeder, associated with Mesh Corner 1 and for the New Cross 2 Feeder, associated with Mesh Corner 3.

In accordance with the Design Intent Document (DID) that was issued to NGC by the Contractor on 15 August 2000 (actually entitled Detailed Design Specification), the proposed refurbishment work would involve the engineering of new protection panels, with the provision of some new protection relays, to replace existing relays close to life expiry and with the re-use of some existing relays. Any protection equipment not being re-used was to be offered to NGC for their retention (maybe for re-use elsewhere or for spares), or it was to be disposed of.

All the new protection panels for the refurbishment work at Wimbledon were manufactured in 2000-2001 and outages had been planned to facilitate the installation and commissioning of the refurbished protection schemes for all three Feeders within 2001. It transpired, however, that only the Mesh Corner 3 commissioning work could be completed in 2001, which covered only the New Cross 2 Feeder. The Mesh Corner 1 work, including the New Cross 1 and Beddington 1 Feeders, had to wait until outages became possible in 2003. These outages were in place at the time of the incident of 28 August 2003. The refurbished protection schemes associated with Mesh Corner 1 were stored from 2001, until their installation and commissioning commenced in 2003.

6.2 Summary of the incident

It is not necessary to repeat here all the details that led up the incident of 28 August 2003 except to concur with NGC's published report of 10 September (paragraph 115) that the blackout occurred when the New Cross 2 Back-Up overcurrent protection incorrectly tripped Mesh Corner 3 and the New Cross 2 Feeder at Wimbledon. This was after the Feeder load current increased to approximately 1460 Amps, following remote opening of the Hurst end of the Hurst - Littlebrook 1 Feeder by NGC National Control, to address an apparent plant problem at Hurst. The operation of the overcurrent protection was incorrect since its intended primary operating threshold had been 5,100 Amps.

It was eventually established by NGC that the actual primary operating threshold of the protection was 1020 Amps, due to the fact that a protection relay with a 1 Amp secondary current rating had been installed and commissioned instead of a relay with a 5 Amp rating. With the increased load current that was seen on 28 August, after the circuit switching at Hurst and with the settings that were applied to the incorrectly rated relay, calculations confirm that it would have taken approximately 6 seconds for the relay to trip.

In response to Consultants' question PBP012 to NGC, as to the load profile of the New Cross 2 Circuit since it had been re-commissioned with a refurbished protection system in 2001, it appears that the maximum demand placed on the circuit in the period had been just 340 MVA, during July 2001. This would have been equivalent to approximately 714 Amps, so the operating threshold of the defective Back-Up Overcurrent protection had not been exceeded until the incident of 28 August 2003. According to NGC Transmission Plant Specification TPS 2.24.3, for Protection Settings Policy, the required Back-Up overcurrent protection threshold setting for the New Cross 2 275 kV circuit would have been 5,100 to 5,200 Amps.

6.3 Study of relay and current transformer ratings and relay settings

Through Consultants' question PBP056, concerning the nameplate continuous rating of the current transformer at Wimbledon for the New Cross 2 circuit and during the Consultant's site visit to Wimbledon on 16 October, it was not possible to confirm the CT rating by viewing the CT nameplate. NGC verbally confirmed later, at a meeting at Hams Hall on 17 October, that the continuous rating is 2,000 Amps.

According to the IEC 60044-1 international standard for Current Transformers, it would be expected that a circuit with a continuous rating of 2,000 Amps would have CT's with ratio and continuous rating denoted by 2000/1 A. The CT's actually applied for the New Cross 2 circuit at Wimbledon are of 1960's vintage and are designated as 1200/600/1 A, with the 1200 A tap in use. This is in accordance with CEGB/NGC historical practice and with NGC Transmission Specification NGTS 3.2.4, where CT's for 275 kV Feeder applications should be designated 1200/600/1 A, but with a continuous current rating of either 2500 A or 2000 A, depending on the associated Circuit Breaker rating. NGC's verbal rating confirmation of 17 October means that the New Cross 2 Feeder CT's have a continuous rating equal to 167% of the rating implied by their description, according to IEC.

It is the fact that NGC/CEGB has traditionally used relatively low ratio CT's, in relation to the continuous current rating of some 275 KV circuits and in relation to the required primary current threshold for Back-Up overcurrent protection, that 5 Amp rated overcurrent relays are required for such circuits, for use in conjunction with CT's that are apparently 1 Amp rated and where the earth fault relays would be rated at 1 Amp.

Substation: Wimbledon. 275kV.

Circuit: New Cross 2 System Backup relays

Relay Function: overcurrent and earth fault system back up

Relay type: MCGG42 and MCGG22

Serial number: not known

CT Ratio: 1200/600/1

Date: 10.5.1

Prepared By: TJM

OVERCURRENT.

In accordance with TPS 2.6.2 section 3.1 Feeders, 115% of 4450A =5118A.
(Source of line data is gridnet, eng navigator, eng documents, thermal rating and prot schedules.)
Nearest Actual Current Setting is: 5100A

TM set to achieve operating time of 1s, assuming that fault infeed to feeder is 15000MVA at 275kV, =31493A.

TM = ((I ^ 0.02) - 1) * (reqd. op time) / (0.14)

TM = ((**(31493/5100)** ^ 0.02) - 1) * **(1)** / (0.14) = 0.264

OVERCURRENT.
Setting is 0.85 x In = 4.25 A on 5A relay and 1200/1 ratio =5100 A. R=Y=B.
SI curve,
TM= 0.275

Figure 11 – Scanned Copy of the NGC Setting Calculations for New X 2 BUOC

The practice of applying 5 Amp rated relays with CT's apparently rated at 1 Amp (NGC CT standard) is uncommon according to the Consultant's international practice, but it is a technically acceptable practice, which is sometimes necessary. In response to a question from the Consultants during the visit made to Wimbledon substation, NGC stated that out of 1,408 type MCGG relays applied to its network, only 86 of the relays from the particular manufacturer are rated at 5 Amps.

In consideration of the range of MCGG relay models available from the manufacturer, it would normally be possible to apply an MCGG52 relay to provide combined 2-phase overcurrent and earth fault System Back-Up protection within a single unit. With the special application requirement at Wimbledon, for the Feeder overcurrent relay elements to have 5 Amp secondary ratings and for the earth fault element to have a 1 Amp rating, it was necessary to apply separate overcurrent and earth fault relays, since hybrid current ratings are not available for the MCGG range of relays. The feeder overcurrent and earth fault protection at Wimbledon was to be provided by a 2-phase, 5 Amp rated MCGG42 unit and by a 1-phase, 1 Amp rated MGGG22 unit, respectively. The combined arrangement, as photographed by the Consultants on site on 16 October 2003, for the New Cross 2 Feeder, is shown in Figure 12. It can be seen that the relays have clearly visible data tables in the top right quadrants of their front plates, and the relay rated current is one of a number of parameters that is clearly displayed.

Figure 12 – View of New X 2 Back-Up Overcurrent & Earth Fault Relays at Wimbledon

By comparison to Wimbledon, the overcurrent protection at New Cross, for each feeder from Wimbledon, is provided by a 3-phase, 5 Amp rated MCGG62 unit and by a 1-phase, 1 Amp rated MGGG22 unit.

6.4 Back- up protection refurbishment work for Wimbledon

From the outset of the investigation, the Consultants were puzzled by the fact that Table 6 in Appendix 1 of NGC's London incident report of 10 September listed the type of Back-Up overcurrent relay for the New Cross 2 Feeder at Wimbledon as having been type DCD314. This type of relay is a multi-function numerical relay (see Figure 4) which is of different manufacture to the MCCG range of relays. The DCD relay has a dual 1/5 Amp secondary rating and so NGC's report that a relay of incorrect secondary rating had been applied was not initially understood by the Consultants, or by other readers with some knowledge of protection. Later, in response to Consultants' question PBP055, NGC confirmed that they had incorrectly listed the New Cross 2 Back-Up protection at Wimbledon and that there were some other errors in the table. A revised Table 6 was then submitted, where the New Cross 2 Back-Up protection was listed as being type MCGG42 and having been commissioned in 2001. Extracts from the original and revised Tables are given in Figure 13 and Figure 14.

Circuit	Type of Protection	Equipment at given substation	Equipment at given substation	Year Commissioned
New Cross – Wimbledon 1		New Cross	Wimbledon 1	
	1st Main Feeder Protection	LFCB 192	LFCB 192	2003
	2nd Main Feeder Protection	Microphase FM	Microphase FM	1997
	Back-up overcurrent	MCGG62	MCGG42	1997
New Cross – Wimbledon 2		New Cross	Wimbledon 2	
	1st Main Feeder Protection	LFCB 192	LFCB 192	2001
	2nd Main Feeder Protection	Microphase FM	Microphase FM	1996
	Back-up overcurrent	MCGG62	DCD314A	2001

Figure 13 – Print of Original Table 6 in Appendix 1 of NGC Report of 10/09/03

Circuit	Type of Protection	Equipment at given substation	Equipment at given substation	Year Commissioned
New Cross – Wimbledon 1		New Cross	Wimbledon 1	
	1st Main Feeder Protection	LFCB 192	LFCB 192	2003
	2nd Main Feeder Protection	Microphase FM	Microphase FM	1997
	Back-up overcurrent	MCGG62	MCGG42	1997
New Cross – Wimbledon 2		New Cross	Wimbledon 2	
	1st Main Feeder Protection	LFCB 192	LFCB 192	2001
	2nd Main Feeder Protection	Microphase FM	Microphase FM	1996
	Back-up overcurrent	MCGG62	MCGG42	2001

Figure 14 – Revised Table 6 for Appendix 1 of NGC Report (in Response to PBP055)

Copies of correspondence and background documents related to the 2001 protection refurbishment at Wimbledon were requested from NGC (Consultants' question PBP025) and the material that was made available has been carefully reviewed by the Consultants. With the initial information provided, the Consultants noted that there was little of the correspondence that would have been expected between NGC and the Contractor for Wimbledon. NGC was later able to provide pertinent copies of some of their e-mails to the Contractor ✂.

Following their award of contract, to refurbish the 275 kV protection systems at Wimbledon, the Contractor submitted a Detailed Technical Specification document to NGC on 15 August 2000. The document would now be classed as the "Design Intent Document" (DID), which is required by NGC for an asset replacement project, in accordance with Section 1.6, Level 1 of the NGC Tender Manual. Relevant scanned extracts from the Contractor's "DID" are provided for reference in Figure 15.

4.2.2): Relay Panel 13-Mesh Corner 3

Remove the relay panel together with the following equipment, including the wiring tails to the wall mounted terminal box:

Mesh Corner –	Circulating Current Relay 1	CAG34	0.025-0.1Amp
	Circulating Current Relay 2	CAG34	0.025-0.1Amp
	Protection CT Supervision	DBA2	0-15V
	Protection Defective Timing	VTT14	0-10secs
	Trip Relay 1	LTC2	
	Trip Relay 2	LTC2	
	Supply Supervision 1	B26	
	Supply Supervision 2	B26	
New Cross 2 SBUP –	Two Phase Overcurrent	MCGG42	5amp (Retain)
	Earth Fault	MCGG22	1amp (Retain)
	Trip Relay	TR212	
New Cross 2 Overload Alarm Relay		FSL	80-160%, 1amp

New Cross 2 System Back Up Protection

Install the following equipment, which is to be hard wired but adhering to the engineering logic of TPS 5/33 scheme, BACKUP -001:

Overcurrent and Earth Fault Relay	DCD314A	*amp
14 way Test Block	RMLG01	
Protection Trip Relay	TR231	
Supply Supervision Relay	XR152	
Fuses and Links as necessary		

The following orders have been placed, covering the above equipment:

Order No.	Supplier	Items	Due Date	Received

Note: Within the New Cross 2 section of the DID, it appears that the System Back-Up protection was incorrectly labelled as New Cross 1, since this had already been covered earlier in the DID. For clarity, the Consultants made a pencil change to the heading in the above scanned extract from the DID from “1” to “2”.

Figure 15 – Extracts from Contractor’s Refurbishment Proposals

With reference to Figure 15 and to the complete DID, it was clear that the Contractor’s original proposal had been to replace all the original Feeder Back-Up overcurrent and earth fault relays, for the three 275 kV feeders within their scope of work, with dual-rated, multi-function numerical relays type DCD314, in new protection panels. In the case of the New Cross Feeders 1 & 2, the Contractor had noted that the original Back-Up protection relays for both the Feeders at Wimbledon were 5 Amp rated MCGG42 overcurrent relays and 1 Amp rated MCGG22 earth fault relays. The Contractor’s initial proposal was obviously to salvage and “retain” those MCGG relays for NGC’s other use (e.g. for spares).

The fact that dual 1/5 Amp rated DCD relays (depending on the connection of their CT inputs) were originally proposed by the Contractor for Feeder Back-Up protection and the fact that they had been listed as having a rating of ” * Amp” in the Contractor’s DID (see

Figure 15), led the Consultants initially to believe that the ambiguous rated current entry in the DID might have been the source of the secondary rated current selection error for the MCGG42 overcurrent relay that was ultimately used for the New Cross 2 Feeder. Once NGC issued their revised Table 6 and following discussion with NGC during the Consultant's visit to Wimbledon Substation, it was clear that a decision had been made to re-use the existing MCGG relays in lieu of providing DCD relays, which was in accordance with the Contractor's subsequent General Arrangement Drawing (see Figure 16).

EQUIPMENT DETAILS – SYSTEM BACKUP					
R/P ITEM	C.D. RELAY REFERENCE	SUB-RACK	ARTICLE NUMBER	CASE SIZE	DESCRIPTION
23	OCR	8	MCGG42	6	OVERCURRENT RELAY
24	EFR	8	MCGG22	6	EARTH FAULT RELAY

Figure 16 – Extract from Contractor's General Arrangement Drawing

During a visit to Wimbledon, the Consultants noted the model and serial numbers of the MCGG relays for the New Cross 1 and 2 Feeders. With the exception of the MCGG42 Back-up overcurrent relay for the non-commissioned New Cross 1 Feeder, it was found that the other three sets of MCGG42 / MCGG22 relays had serial numbers with "J" suffixes. According to the Consultant's familiarity with the manufacturer's serial numbering system, this confirmed that their year of manufacture was 1997, which concurs with Table 6, Appendix 1 of NGC's incident report (see Figure 14), where, as part of a protection scheme that was refurbished in 2003, the New Cross 1 Feeder relays are listed as being of 1997 vintage.

The Consultants requested copies of any NGC contract correspondence from 2000/2001 that might confirm the basis for the change from the Contractor's proposed provision of new DCD relays to the actual re-use of MCGG relays. All that was provided was a copy of a Contractor's drawing, which confirmed that the New Cross 2 System Back-Up protection would be type MCGG (see Figure 16). The reversion to the re-use of MCGG relays lines up with NGC's explanation to the Consultants during their visit to Wimbledon on 16 October 2003, where NGC stated that there had been an intention to re-use equipment that was relatively new, wherever possible.

6.5 Back- up overcurrent relay rating selection error for New Cross 2

Since the Contractors for the Wimbledon refurbishment were to re-use the original 1997 System Back-Up protection relays for the New cross feeders and since their DID had listed the original Feeder Back-Up overcurrent relays as being 5 Amp rated type MCGG42, it was then necessary to establish how a 1 Amp relay ended up being installed and commissioned instead. It was first necessary to consider the possibility of whether the original relay, from 1997, had already been erroneously rated at 1 Amp for a number of years and whether the contractors had mistakenly listed it as being a 5 Amp relay, through cutting and pasting their survey notes from the New Cross 1 Feeder (see the Note added to the scanned extract in Figure 15).

In the commissioning test record from 1 June 2001, the relay under test was clearly identified as being a 1 Amp MCGG42 (see Figure 22). The relay serial number that was also recorded had an “M” suffix. From the Consultant’s understanding of the relay manufacturer’s model numbering system at the time, the “M” suffix confirms that the relay that had been tested had been of 2000 vintage, rather than the expected 1997 (“J”) vintage with the re-use of the original New Cross 2 Feeder relay. The Consultant’s had noted during their site visit to Wimbledon that the accompanying New Cross 2 MCGG22 earth fault relay had a model number with a “J” suffix, which implies that the 1997 earth fault relay had been re-used. The copy of the Contractor’s test record (PTS 264) for the earth fault protection that was checked by the Consultants confirms that a 1997 (“J”) earth fault relay had been tested. Thus, the original overcurrent relay had not been re-used for the New Cross 2 Feeder for some reason, but the earth fault relay had. The original overcurrent relay had evidently been replaced.

The serial number of the New Cross 2 MCGG42 System Back-Up overcurrent relay that was commissioned in 2001 was recorded in both the Contractor’s commissioning test record and in the NGC MARS settings sheet for the relay (see Section 6.6.2, Figure 22 and Figure 23). NGC was also able to provide a faxed copy of an order placed on 2 May 2001 by the refurbishment Contractor to the relay manufacturer for a relay with same serial number. A copy of the Manufacturer’s order acknowledgement was also provided. Somewhat unusually, the Contractor had placed an order for a single MCGG42 relay. Typically, a Contractor would place an order for multiple relays from the manufacturer when working on a refurbishment project. The order that had been placed on 2 May 2001 had requested a latest despatch date of 20 May 2001. The manufacturer’s agreed despatch date was 18 May 2001. As confirmed in the relay manufacturer’s order acknowledgement and as the Consultants were able to deduce by reference to the 10th letter of the full relay model number, through knowledge of the particular relay model numbering system, the substitute MCGG42 overcurrent relay that was supplied and tested did have a 1 Amp secondary current rating.

From the Consultant’s knowledge of the manufacturer at the time the 1 Amp MCGG42 relay was ordered, they did not hold such relays as stock items, but they manufactured to order. NGC has also confirmed this understanding to be true, through correspondence discussion. It is also the Consultant’s experience of the manufacturer that the requested and agreed delivery period of just 16 days was too short in relation to their normal manufacturing lead-time for the product. Furthermore, with reference to the “M” suffix of the relay serial number, it appears that the relay ordered and promised for delivery in mid-2001 had actually been manufactured in 2000. Thus, it appears that the manufacturer had taken an unusual step to satisfy what appears to have been an urgent demand from a contractor for the delivery of a single relay The Consultants are familiar with some of the perfectly acceptable means by which the particular manufacturer would endeavour to assist a customer by supplying a relay in less than the manufacturing lead time.

From the review of documentation, it appears that the planned re-use of the 1997 MCGG42 overcurrent relay for the New Cross 2 Feeder had to be abandoned shortly before the feeder re-commissioning date. NGC confirmed that the New Cross 2 feeder was re-commissioned and went back into service on 26 May 2001, which was just 8 days after the apparent despatch of the replacement MCGG42 relay by the manufacturer. It is not known why the re-use of the 1997 relay had to be abandoned or why a 1 Amp relay was ordered as a replacement for the original 5 Amp relay.

Through question PBP098, the Consultants requested copies of any contractual correspondence from NGC that might shed some light on the reason for the Contractor's sudden relay substitution, but the only document that was initially provided was a copy of the Contractor's order and the Manufacturer's order acknowledgement for the substitute 1 amp relay. NGC had stated that their investigations, including a search of their archives, had not revealed the reason for the change. At the meeting held at Wimbledon, NGC's stated analysis of the available information suggested that a decision might have been taken to substitute a contemporary variant of the MCGG42 unit, procurable from the manufacturer, rather than retain the existing relay. However, no such replacement was made for the New Cross 1 protection refurbishment, since the MCGG42 relay that was removed from the un-commissioned New Cross 1 panel, to replace the New Cross 2 relay after the incorrect trip, was a 1997 ("J") relay and not a 2001 relay.

In correspondence with the Consultants in January 2004, NGC made reference to a series of e-mail correspondence between themselves and the Contractor. Since, this correspondence had not earlier been presented in response to question PBP098, copies were requested by the Consultants. Some e-mail correspondence was provided, but it was mainly from NGC to the Contractor. ✂ When requested to provide a copy of any reply, NGC stated that are unable to find a reply from the Contractor. A request was then made as to whether NGC could obtain a copy of the Contractor's response directly from the Contractor, but such a copy has not been obtained to date. A summary of the available correspondence and its apparent significance is given as follows:

- **17 February 2001** – Contractor e-mailed copies of spreadsheets listing details of new protection relays to be provided at New Cross and at Wimbledon, as part of their protection refurbishment work:

  With regard to System Back-Up protection for the No. 2 feeder between Wimbledon and New Cross, there were no new relays listed for the Wimbledon end, but the following new relays were to be provided at the New Cross end:

New Cross 275kV Substation	Serial No	Circuit Ref
Wimbledon 2 - Back Up Protection		
MCGG62N1CB1003E	688182M	OCIT,OC
MCGG22L1CB0753D	688179M	EFRIT,EFR

From examination of the MCGG relay serial numbers and from the Consultant's knowledge of the relay manufacturers system at the time, the "M" suffix indicates that both relays were manufactured in 2000. This would have been in line with a protection refurbishment programme planned for summer 2001, where it was expected that the required relays would have been ordered and probably manufactured in 2000, with the Contractor's confirmation of details being sent in February 2001.

From the Consultant's knowledge of the manufacturer's model numbering system for the MCGG range of relays, the letter "B" as the 10th entry in the relay serial numbers, indicates that both the overcurrent and earth fault relays were of 1 Amp secondary rating.

- **06 March 2001** - NGC noted problems with some of the proposed new protection relays and sent an e-mail to the Contractors that included the following extracted comments. Those that are particularly pertinent to this investigation have been underlined. It should be noted that this type of correspondence is not unusual during the often complex process of refurbishing existing protection:

  "…have noticed from the list of relays sent to me by (Contractor) that the Wimbledon SGT 1A, 3A and SGT 3A, 3B Reyrolle B1 relays for NEF have a setting range of 50 to 200%. It is our policy to normally set these relays to 20% on the 1200/1 ratio, i.e., 240A.

  Could you change the range (i.e. relay) to suit?

  <u>I have also noticed a similar problem with the New X MCGG42 on the Wimb 2 feeder. In accordance with our relay setting document TPS2.6.2, we'd set it to 115% of the feeder rating, 115% (1660MVA)= 4008A . Selecting 3.4A setting on a 5A relay gives primary setting of 3.4A (1200)= 4080A. (i.e., 5A relay required, not a 1A relay.)</u>

  <u>(This problem would not occur with DCD relays, as each relay comes with a 5A or 1A element. But there may be a minor change to the schematic for DCD relays to show the connection to the 5A element. ……)"</u>

It is clear from this e-mail that NGC had correctly identified that the new overcurrent relay proposed by the Contractors for the <u>New Cross</u> end of Feeder No. 2 from Wimbledon, was a 1 Amp rated relay, when a 5 Amp relay was actually required. NGC also took the trouble to explain why a 5 Amp relay was required to accompany a 1 Amp earth fault relay for the Wimbledon 2 feeder – given that it is somewhat unusual for a 5 Amp relay to be applied with CT's with a 1 Amp secondary rating (refer to Section 6.5). NGC then went on to highlight what would have been the case for the application of the protection relay type DCD, from another manufacturer, as had originally been proposed in the Contractor's DID for Wimbledon

There is a slight error in the NGC e-mail in that it refers to a 2-phase type MCGG42 relay, which was the existing type used at the Wimbledon end of the feeder, rather than the new 3-phase type MCGG62 relay that the Contractor was proposing for New Cross end. ✂

Whilst the actual reason for the installation of an incorrectly rated replacement relay at Wimbledon might never be confirmed, it must be recognised that this type of error is always possible and that it is the quality of the commissioning practices and procedures and their rigorous application and enforcement that will prevent such an error from adversely impacting on system operation at a future date.

6.6 Review of back- up overcurrent commissioning for New Cross 2

6.6.1 Review of commissioning procedures and responsibilities

A review of the commissioning records made available to the Consultants was conducted with reference to the NGC practices and procedures outlined in Section 4 and with particular reference to Transmission Procedure TP106, for Equipment Commissioning and Decommissioning. A scanned extract from TP106 is provided in Figure 17, which states that a Contractor should select and work to an appropriate Site Commissioning Test (SCT) procedure, where one exists. Only where an SCT does not exist should Contractors use their own standard, or specially prepared documentation.

7.3 Site Commissioning Test Procedures

7.3.1 Contractors will be required to select SCT procedures from the model SCTs agreed by Asset Policy at the time of Type Registration. Where a test requirement is not covered by an SCT procedure, a contractor's or other specially prepared document may be used. In such instances the Commissioning Panel shall require the adequacy of the test documentation to be approved by personnel of appropriate standing, and such approval formally recorded in the Commissioning Panel minutes.

7.3.2 The Chairman of the Commissioning Panel, or his nominated representative, shall confirm that all agreed test procedures relating to Stage 1 commissioning tests are completed prior to Part 1 of the Equipment Acceptance Certificate being issued. On completion of the Stage 2 commissioning tests, each test schedule shall be signed for as 'accepted' by National Grid. This shall be carried out by the person witnessing the tests or, if the tests were unwitnessed, it shall be carried out by the Commissioning Engineer, following both a check that all entries are complete, and that the results, following a cursory examination, appear correct.

Figure 17 – Extract from TP106 - Equipment Commissioning Procedures

For the testing of the MCGG protection relays for the New Cross 2 Feeder in June 2001, the appropriate and available procedure to have been followed at the time, for "Stage-1" commissioning tests, would have been Issue 3 of SCT 20.5.3 of October 2000, which covers Overcurrent and Earth Fault Protection. With reference to Section 7 of SCT 20.5.3, the protection should be tested <u>with the service settings applied</u> and a copy of the NGC MARS summary sheets for the protection relays (refer to Section 4.5) should be attached to the completed SCT documents, since the MARS sheet is NGC's definitive and approved record of the required protection settings.

The Contractor's records of commissioning tests were reviewed by the Consultants. For some reason, the tests conducted and the records made for the New Cross 2 Feeder Back-Up protection were according to the Contractor's own standard procedures (PTS299 for MCGG42 overcurrent relay and PTS264 for MCGG22 earth fault relay) and not to the appropriate NGC procedure (SCT 20.5.3).

It is not clear why the NGC procedure SCT 20.5.3 was not followed, given that the Contractor had adopted NGC procedures for commissioning other items of protection at Wimbledon, but the Contractor's Commissioning Report Quality Plan, which had been signed off as being approved by the NGC Commissioning Panel on 23 March 2001, did clearly indicate the planned use the Contractor's own PTS299 and PTS264 test procedures. With reference to the scanned extract from the Plan given in Figure 18, the Contractor had also identified that these test procedures were to be 100% witnessed by NGC.

Section Number 5 Section Title Back Up Protection

No.	Activity	Manufacturer	Device	Document	Risk	Witness	Signature
1	Inspection of the Equipment/Wiring	N/A	Panel Build	PTS 101	Low	N/A	
2	Measure Insulation Resistance of Secondary Wiring	N/A	Insulation Resistance	PTS 106	Low	N/A	
3	Secondary Injection of Auxiliary Relays	Reyrolle	XR152	PTS 120	Low	N/A	
4	Secondary Injection of Trip Relays	Reyrolle	TR ***	PTS 120	Low	N/A	
5	Secondary Injection of Electronic OCEF Relays	Alstom	MCGG 42	PTS 299	Low	W100	
6	Secondary Injection of Electronic OCEF Relays	Alstom	MCGG 22	PTS 264	Low	W100	
7	Secondary Injection of CT Circuits	N/A	CT Circuits	PTS 122	Low	W100	
8	Functional Checks using "Installation" Circuit Dia	N/A	Scheme Test	PTS 107	Low	W100	
9	Alarm Initiation Tests	N/A	Initiation Tests	PTS 183	Low	W100	
10	Fault Recorder Initiation Tests	N/A	Fault Recorder	PTS 184	Low	W100	

Figure 18 – Extract from the Contractor's Commissioning Report Quality Plan 23/03/01

With reference to item A6 (b) of TP106, as presented in the extract shown in Figure 19, and through the signed Commissioning Report Quality Plan, it had clearly been the Commissioning Panel's original agreement that the Contractor's own test procedures for the New Cross 2 Feeder Back-Up protection were to be witnessed by their representative.

A6 Commissioning Programme Responsibilities

The Commissioning Panel shall record, in the schedule provided in Attachment A, the following Commissioning Programme responsibilities. A separate schedule should be completed for each stage of the project. All 'accepted by' activities shall be carried out by National Grid personnel or other suitably qualified personnel approved by the Commissioning Panel.

(a) ***Pre-commissioning Inspection Schedule***

At the discretion of the Commissioning Panel a formal inspection schedule for small scale projects may be dispensed with.

(b) ***Off-load Commissioning Tests Programme***

The Chairman of the Commissioning Panel and the Commissioning Engineer shall jointly decide, and record below, the extent to which witnessing of tests will be carried out. As a minimum, witnessing should always apply to primary injections, to new types of **Equipment**, or to unusually complex **Equipment**.

Figure 19 – Extract from TP106 - Commissioning Responsibilities

6.6.2 Review of Commissioning Documentation

In response to Consultants' question PBP024, the file of commissioning test records (Commissioning Report) was reviewed by the Consultants and a summary of the review is provided in APPENDIX A.

The Contractor's PTS299 document that was used as the basis for TP106 "Stage-1" commissioning tests for the New Cross 2 overcurrent protection, covered a range of secondary injection tests that were quite thorough and they were apparently well recorded, with each relay current setting, characteristic curve selection and a range of time multiplier settings having been tested. However, the PTS299 record did not include a declaration of the required service settings for the relay or any test results to check the performance of the relay with those specific settings applied.

Along with the PTS299 record, the Table in APPENDIX A shows that the records for a number of other tests, where witnessing had been planned, had not been signed by the NGC representative. In addition, the Commissioning Report Quality Plan signature boxes shown in Figure 18 were also unsigned.

In subsequent correspondence discussions with NGC, via Ofgem, NGC stated that the *"NGC Commissioning Engineer for Wimbledon has confirmed that a collective decision was taken to selectively witness the secondary injection tests associated with the New Cross 2 circuit. Tests relevant to the back-up protection were deemed within the scope of the supplier and were therefore not witnessed by NGC"*. With reference to the scanned extract of TP106, Section 2.12, shown in Figure 20, the selective witnessing decision was a permissible approach, but it is not known why this apparent change of plan occurred or why there appears not to have been a revision of the Commissioning Report Quality Plan to cover the change.

> **2.12 Stage 1 Commissioning**
>
> *Stage 1 commissioning* comprises those Off-load inspections and tests defined in Section 2.4 which are carried out on new or replacement **Equipment** to demonstrate that the **Equipment** is fit for connecting to the in-service **System**, and ready for Stage 2 commissioning. At the discretion of the Commissioning Panel these tests may be carried out by a contractor without being witnessed by National Grid personnel. Finalisation of *Stage 1 commissioning* is signified by completion of PART 1 of the Equipment Acceptance Certificate. See Appendix J

Figure 20 - Extract from TP106 – Stage 1 Commissioning

The Table in APPENDIX A also shows that a high number of test records were signed off on the same date as the PTS299 record for the New Cross 2 overcurrent protection (1 June 2001) and by the same Commissioning Engineer. The Consultants noted that there were also records not listed in the table that he had signed on that same day, which covered CT primary injection tests and protection relay tests for Transformer SGT3A. This date was the latest entered on any of the commissioning records, but it was after the feeder went back into service on 26 May. The conclusion is that the Commissioning Engineer must have completed his documentation for many tests on 1 June 2001, with all of the tests presumably having been conducted at earlier dates, which had not been recorded.

NGC has since confirmed that it is common practice, in their experience, for a Commissioning Engineer to collect all test sheets together, following a complex programme of commissioning, and then to subsequently sign them all off with the same date at a later time. Whilst the sign-off dates for a number of test documents might end up being the same with this practice, it is a matter of concern that non of the documents recorded the dates on which tests were actually performed. The concern is that in the event of implementing any protection setting changes, there would be no absolute proof of which protection settings had been tested – assuming that tests with protection service settings are performed.

No documentation has been made available to confirm exactly when the New Cross 2 Feeder overcurrent protection was tested by the Contractor or when the required service settings were applied to the MCGG42 relay in question and no evidence has been provided of any relay tests having been conducted after the application of the service settings.

Since virtually the entire range of MCGG42 relay settings had been tested through the PTS299 procedure, it might be argued that there would be confidence with the subsequent application of service settings without retesting, but that is a flawed argument – especially for the particular type of relay in question. According to the Consultant's background knowledge, the type of relay being tested did once suffer from some generic setting selection switch problems (faulty DIL switches). Where protection relays have physical selection switches, potentiometers or other physical setting components it is always advisable that the service settings should be applied and then tested. The testing of protection systems with their service settings applied has been a long established practice within the UK Electricity Supply Industry and it is also the requirement of NGC procedure SCT 20.5.3, which would have been applicable.

In subsequent correspondence discussions with NGC, via Ofgem, NGC stated their understanding that the Contractor's Commissioning Engineer had performed tests with service settings applied, but they were unable to state the date on which the tests were performed and who had witnessed the tests to support their understanding. NGC was also unable to explain why there was no documentary record of the tests having been conducted.

One other important commissioning check, which is highly pertinent in this case and which is formalised in NGC procedure SCT 20.5.3, is to check that the secondary current rating(s) of the protection relay(s) under test is(are) correct, as highlighted by the scanned extract from Section 5 of SCT 20.5.3 given in Figure 21.

SCT 20.5.3
Issue 3
October 2000

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5 INITIAL CHECKS

Check that the A.C. current rating is correct. ☐

Check that the auxiliary supply voltage is the same as the relay rating as marked on the fascia. ☐

Ensure that the polarity of the auxiliary supply is correct before energising the relay. ☐

Energise the relay and check that no warning LEDs/messages are illuminated/displayed once any start up sequence is finished and that normal power indication (ie green LED) is illuminated/displayed. ☐

Figure 21 – Extract from SCT 20.5.3 – Initial Relay Checks

As already identified in Section 6.3 in relation to Figure 12, the rating of the New Cross 2 MCGG42 overcurrent relay was clearly visible and it was recorded by the Contractor's Commissioning Engineer in the PTS299 test record. Some initial relay checks were also prompted in Section 2 of the PTS299 record, as indicated in the scanned extract from the record given in Figure 22, but there was no specific prompt for a check to confirm that the correct relay current rating had been selected. The check on the assembly drawing would not have covered this, since the required relay rating is was not marked.

PLANT TEST SCHEDULE — PTS 299 — PTS 299, Rev. 0, Page 1 of 3

OVERCURRENT & EARTH FAULT RELAY
ALSTOM TYPE MCGG42

Customer	Site	Contract No
N.G.C.	WIMBLEDON	A65-03
Circuit	**Panel No**	**Assembly Drawing**
NEW CROSS 2	MC3 NEW X 2	42 | 133974

Section 1 General Information

Relay Type	Model No	Serial No
MCGG42		862472H
Rated Current (In)	**Rated Voltage (Vn)**	**Auxiliary Voltage (Vx)**
1A	125V DC	125V DC

Section 2 Preliminary Checks

2.1 Confirm relay corresponds to relevant general arrangement drawing............ ☑

2.2 Check relay has not been damaged during transit or installation............ ☑

2.3 Confirm relay earthed............ ☑

2.4 Confirm the relay DC auxiliary supply polarity is correct & measure and record voltage............ ☑

Voltage 125 V

		Phase	Earth
2.5	Check relay case CT shorting links............	☑	☐
2.6	Check LED indication/reset............	☑	☐
2.7	Check relay test feature............	☑	☐
2.8	Check relay output contact............	☑	☐

Figure 22 – Extract from Contractor's PTS299 Test Record for New Cross 2

6.6.3 Review of Settings Documentation

With the MARS sheet being the official list of settings to be applied to any NGC protection relay, a request was made to NGC (Consultants' question PBP090) for a copy of the MARS settings sheet that was applicable when the time the protection was commissioned in 2001. A scanned copy of the sheet was provided, but with the NGC signatures partially erased. The date of the settings calculation signature had been entered as 11 May 2001 and the registered print date for the sheet was of the same date. With reference to Figure 11, in Section 6.3, the calculation document for derivation of the required settings was dated 10 May 2001.

The date of the settings application signature on the MARS sheet had been entered as 18 January 2002, which was more than 6 months after the New Cross 2 feeder had been returned to service with its refurbished protection systems. Through subsequent correspondence discussion, NGC stated that the representative of their Area Manager, for what was then their South East Area, verified the relay settings on 18 January 2002 and that such a time lag time lag for settings confirmation was not uncommon as part of the sign-off process for completed work. Nevertheless, the Consultants' view and their understanding of the requirements of NGC's Transmission Procedure TPS106, is that there should also have been a signed record to confirm that the required service settings had been applied and tested before the feeder was returned to service on 26 May 2001.

A copy of the revised MARS sheet, following the incident of 28 August, was also made available by NGC, after the 1 Amp Overcurrent relay had been replaced by a 5 Amp relay. An examination of this sheet indicates that the original was created on 18 January 2002, which was the date that the application of settings to the previous relay was confirmed on site by the NGC Area representative and that the settings calculations were checked on 5 February, but there are no dated signature boxes on the copy of the sheet provided.

Copied extracts of the scanned 2001 MARS sheet provided by NGC are given in Figure 23. Contrary to normal procedure (except for signatures), the entire MARS sheet had not been completed with typed entries. It appears that the overcurrent and earth fault relay model numbers had been added as handwritten entries some time after the sheet had been printed on 11 May 2001. The earliest date at which the overcurrent relay serial number could possibly have been known was 2 May, following the manufacturer's order acknowledgement to the Contractor (see Section 6.5), but this might not have been disseminated to NGC until after the MARS sheet had been printed.

With reference to the manufacturer's order confirmation for the substitute relay and to the Contractor's commissioning record extract given in Figure 22, it is clear that the relay with serial number "862472M" was a 1 Amp rated relay, which contradicts the required 5 Amp relay indicated on the MARS sheet extract shown in Figure 23. Thus, the MARS sheet became technically in error, but not obviously so. In subsequent correspondence discussion with NGC, via Ofgem, about the effective relay rating contradiction shown on the MARS sheet, NGC stated that the overcurrent and earth fault relay serial numbers had been written on to their office copy of the MARS sheet by the Contractor's Commissioning Engineer, after he had noted the relay serial numbers on site.

v	Relay Function	Type	Serial	Rating	Range	CT Ratio
A	EARTH FAULT BACK UP	MCGG22	003411J	1A	STANDARD	1200/600/1
A	OVER CURRENT BACK UP	MCGG42	862472M	5A	STANDARD	1200/600/1

```
CURRENT SETTING=0.85          TIME SETTING=0.275TM     (5100A,2429MVA)   R=B
OPERATING CHARACTERISTIC=SI

                              SWITCH SETTINGS
                              ---------------
      Is  (xIn)           CHARAC                xt                 I inst  (xIs)
    ----------------     -----------     ------------------       -------------
    0.1|   =>  |0.05     0|  <=   |1     0.025|  <=   |0.05       0|   <=   |1
    0.1|   =>  |0        0|  <=   |1         0|   =>  |0.05       0|   <=   |2
    0.2|   =>  |0        0|  <=   |1         0|  <=   |0.1        0|   <=   |4
    0.4|   =>  |0                            0|   =>  |0.2        0|   <=   |8
    0.4|   =>  |0                            0|  <=   |0.2        0|   <=   |16
    0.4|   =>  |0                            0|  <=   |0.4        0|    =>  |inf
    0.8|  <=   |0
```

Figure 23 – Extracts from Wimbledon - New Cross 2 SBU Protection MARS Sheet

The fact that there is no documentary evidence available for commissioning tests having been performed for the New Cross 2 Back-Up protection with its service settings applied, the fact that the required 5 Amp overcurrent relay rating displayed on the MARS sheet was at odds with the actual relay rating noted by the Commissioning Engineer in the Contractor's PTS299 test record and the fact that the application of settings confirmation date entered by the NGC signatory on the MARS sheet was more than 6 months after the feeder had been returned to service, prompts the question as to whether the MARS sheet had actually been in the possession of the Contractor's Commissioning Engineer at the time of commissioning tests. No documentary evidence has been provided to confirm that it was, but since the MARS sheet was apparently issued on 11 May 2001, which was 7 days before the promised despatch date of the replacement MCGG42 relay by the manufacturer, the sheet would have been available at the time of commissioning tests. It can only be concluded that the sheet was either not in the possession of the Commissioning Engineer at the time of testing, for whatever reason, or that he did not carefully refer to it, or that he did not refer to it at all, which would be surprising.

With reference to Figure 23, it can be seen that the MARS sheet highlights the required primary operating current of the overcurrent protection, together with the CT ratio in use and the rated current of the relay. If the MARS sheet had been in the possession of the Commissioning Engineer at the time the commissioning tests were performed and if the relay had been tested with its required service settings applied, the Commissioning Engineer might have intuitively back-calculated from the secondary pick-up current test result to realise that the primary operating current for the relay under test would be 5 times too low in comparison to the MARS sheet requirement, but only if tests had been conducted with service settings applied. He should certainly have spotted that the MARS sheet had listed a

5 Amp relay and that this was at odds with the 1 Amp rating that he had entered in the PTS299 commissioning record.

Whenever the service settings were actually applied to the protection in question, the action of applying the settings would not, in itself, have highlighted a relay secondary current rating selection error. As already mentioned in Section 6.3, the current pick up setting of an MCGG relay, in common with many other modern relays, is not actually expressed in Amps, but as a multiple of relay rated current (x I_n). The New Cross 2 application required a current setting of 5,100 Amps primary, which was 4.25 Amps secondary. With the planned re-use of the original (1997) MCGG42 relay, with I_n = 5 Amp, the required secondary setting was 0.85 x I_n. However, it was also possible to apply a setting of 0.85 x I_n to the incorrectly substituted relay with I_n = 1 Amp, which is why the action of applying the settings would not have highlighted the incorrect relay installation.

The Consultants consider the absence of any documentary evidence of the protection having been tested with the required service settings applied and the acceptance of a test procedure that did not demand such tests as being required, was a serious collective failing of commissioning management by the Commissioning Panel, which was made up of both NGC and Contractor's personnel and which is Chaired by NGC.

6.6.4 Timescale for commissioning

Regarding time scales for the Commissioning work at Wimbledon, it is evident that there had been some slippage. With reference to NGC information provided in response to questions PBP026 and PBP027, the Contractor's time chart of August 2000 showed that commissioning of the protection associated with Mesh Corner 1 and the New Cross 1/Beddington 1 Feeders, was planned to follow Mesh Corner 3/New Cross 2 commissioning within the 2001 summer outage window, but the Mesh Corner 1work did not take place that year. In response to question PBP097, this was because of start date slippage for the work related to Mesh Corner 3/New Cross 2, due to the impact of an earlier local distribution system fault. The impact of a subsequent NGC Hurst – New Cross circuit fault resulted in the delayed Mesh Corner 1/New Cross 1 outage having to be cancelled for 2001.

The Contractor's planned 2001 commissioning dates for the Mesh Corner 3/New Cross 2 Feeder protection, as agreed by the NGC Commissioning Panel on 23 March, were 2 April to 11 May, but the rescheduled dates spanned 6 April to 26 May.

As discussed in Section 6.6.2, the test record for the New Cross 2 Feeder overcurrent protection at Wimbledon was signed off by the Contractor's Commissioning Engineer on 1 June 2001. As highlighted in yellow in the Table in APPENDIX A, the same Commissioning Engineer signed off a number of other test records on that day. It was also noted that there were records not listed in the Table, which covered CT primary injection tests and protection relay tests for Transformer SGT3A, which he signed on the same day.

6.6.5 Commissioning engineer authorisation

Regarding Commissioning Engineer qualification and authorisation, the signatory of the overcurrent relay test records for the New Cross 2 Feeder Back-Up Overcurrent protection was obviously the Contractors main Commissioning Engineer for the work at Wimbledon, since he had signed most of the other test records and some of these had also be signed by the NGC representative. With reference to Section 4.6.2, he would undoubtedly have been vetted and approved by the NGC Commissioning Panel that had been created for the project.

6.7 Back- up overcurrent remedial action for the New Cross 2 feeder

When checking MCGG relay serial numbers during their visit to Wimbledon, the Consultants expected to find a new overcurrent relay within the New Cross 2 panel, following the 1 Amp relay error discovered by NGC on 28 August 2003. However, the only new relay noted was the overcurrent located within the New Cross 1 panel, which was still in the process of being commissioned. The New Cross 1 earth fault relay and both the overcurrent and earth fault relays in the New Cross 2 panel were of 1997 vintage.

As summarised in Section 6.1, the panels for both the New Cross circuits for Wimbledon had been manufactured/refurbished at the same time in 2001, but only the New Cross 2 panels had actually been commissioned in 2001. The New Cross 1 panels were stored until outages became possible in 2003 to facilitate their installation and commissioning. The suggestion made by NGC during the Consultant's visit to Wimbledon, regarding the observed location of a new MCGG42 relay in the New Cross 1 panel, was that the 5A MCGG42 relay must have been removed from the non-commissioned New Cross 1 panel, soon after the incident on 28 August 2003, to replace the erroneous 1A relay in the New Cross 2 panel. This would have allowed the New Cross 2 Feeder to be securely and quickly restored after the blackout. A new MCGG42 relay would subsequently have been obtained to replace the relay taken from the New Cross 1 panel. This explanation was understood and was accepted by the Consultants. A check on the copy of the current MARS sheet for the protection confirmed that the relay serial numbers noted by the Consultants on site for New Cross 2 agreed with the numbers recorded on the MARS sheet.

6.8 Summary of the incorrect protection application

1. Less that one month prior to the delayed re-commissioning date of the New Cross 2 Feeder from Wimbledon and its refurbished protection scheme, a substitute MCGG42 overcurrent relay was ordered by the Contractor from the relay manufacturer. This was to be a replacement for the planned re-use of the existing 5 Amp rated MCGG42 of 1997 vintage, which had been retained from the original protection scheme. The relay order effectively requested urgent delivery and the manufacturer obliged.

2. The replacement relay that was ordered, delivered, fitted and commissioned was a 1 Amp relay. It is not known why it was necessary to order a last-minute replacement relay or why a 1 Amp relay was ordered to replace the 5 Amp original.

3. The manufacturer appears to have despatched the relay that had been ordered in May 2001 in well under their normal manufacturing lead-time. It is understood that

the relay actually delivered had been manufactured in 2000 and so the manufacturer appears to have taken an unusual step to provide urgent assistance to the Contractor.

4. The commissioning tests for the replacement 1 Amp relay were in accordance with the Contractor's test procedure PTS299, rather than the appropriate NGC procedure SCT 20.5.3. The NGC procedure required a check to be made as to the correct current rating of the relay to be tested, for it to be tested with its service settings applied and for the definitive NGC MARS setting summary sheet to be attached to the completed test document. The Contractor's procedure was based on testing virtually all the relay settings, but not the service settings.

5. NGC has confirmed that Wimbledon Mesh Corner 3 and the New Cross 2 Feeder was re-commissioned on 26 May 2001. The record of back-up protection tests for New Cross 2, along with many other test records, was signed off on 1 June 2001, with no record of the actual date of relay testing. There is also no evidence of tests having been conducted with the required service settings applied.

6. The NGC MARS sheet, which displays the serial number of the relay that was tested, had the required relay rating clearly listed as 5 Amps, which differs from the 1 Amp rating that was clearly recorded in the Contractor's commissioning test record. If the MARS sheet had been in the possession of the Contractor's Commissioning Engineer at the time of commissioning and if it had been carefully referred to, there would have been a good chance that the relay rating error would have been spotted. The MARS sheet appears to have been prepared before the date of commissioning and so it would have been available, but no documentary evidence has been provided to confirm that the MARS sheet was in the possession of the Contractor's Commissioning Engineer at the unrecorded time of the Commissioning tests.

7. The required New Cross 2 overcurrent protection threshold setting for service, which had been calculated for a 5 Amp rated relay (In = 5 Amps), was 0.85 x I_n. It was also possible to apply this setting to the incorrectly installed 1 Amp relay (In = 1 Amp) and so the action of applying the service settings to the relay would not have highlighted the relay rating error.

8. Testing the protection with the service settings applied, as required when following the NGC procedure SCT 20.5.3, followed by intuitive back-calculation of the primary operating current from the test results and the CT ratio and comparing the result with the declared primary operating current requirement on the NGT MARS sheet would have highlighted the relay rating error.

9. The proposed use of the Contractor's own test procedure for the Back-Up Overcurrent and Earth Fault protection, rather than the appropriate NGC procedure, was detailed in the Contractor's Commissioning Report Quality Plan, which had been signed as approved by the NGC Commissioning Panel on 23 March 2001. The approved Plan also required the Back-Up protection tests to be 100% witnessed by NGC. In the copies of the Plan and the completed test procedure documents

provided to the Consultants for review, the customer witness (NGC) signatures are missing.

10. NGC has since stated that their Commissioning Engineer for Wimbledon has confirmed that a collective decision was taken to selectively witness the secondary injection tests associated with the New Cross 2 circuit. Tests relevant to the back-up protection were deemed to be within the scope of the supplier and were therefore not witnessed by NGC. The Commissioning Report Quality Plan does not appear to have been revised and no other documentary evidence has been provided to confirm this change of plan.

11. There had been slippage in the planned progress of work for the Wimbledon protection refurbishment, with the Mesh Corner 3/New Cross 2 start date having been delayed by a distribution system fault. ✂ The planned subsequent work for Mesh Corner 1 eventually had to be put on hold until 2003, due to the impact of an NGC feeder fault between Hurst and New Cross. The Mesh Corner 1 refurbishment equipment had to be held in storage for 2 years.

6.9 Conclusions regarding the London incident

The following conclusions are drawn with regard to the incorrect trip of the New Cross 2 circuit on 28 August 2003:

1. It was due to the erroneous substitution of an overcurrent relay of incorrect rating just prior to commissioning, for reasons unknown.

2. There was apparently a collective commissioning management failing of both NGC and the Contractor, as members of the Commissioning Panel chaired by NGC, to ensure that the Back-Up protection was commissioned according to NGC's established standard procedures, supported by dated documentary evidence of the required service settings having been tested and of the tests having been witnessed, as planned.

3. If the definitive NGC MARS setting sheet for the protection had been in the possession of the Contractor's Commissioning Engineer at the time of commissioning and if careful reference had been made to it, there would have been a good chance that a qualified and experienced Commissioning Engineer would have spotted the relay rating error. The MARS sheet had been created before the protection could have been tested and the particular Engineer would undoubtedly have been vetted and approved by the NGC Commissioning Panel that had been created for the project, but there is an absence of any documentary evidence that he was actually in possession of the MARS sheet during tests and there is no record of the date on which the tests actually took place.

4. The established NGC commissioning procedures are not outside what has been best international practice and they are considered to have been adequate for the type of Back-Up protection that had to be tested, if they had been fully applied. However, the addition of a formal test procedure to prove that the required circuit loadability is not constrained by any protection system, would make NGC's procedures more robust for all types of protection, with it probably becoming a necessity where the latest types of multi-function numerical protection relays are applied.

7. REVIEW OF BIRMINGHAM INCIDENT

7.1 Background to Birmingham incident

The protection that operated incorrectly at Hams Hall on 5 September 2003 was part of a new protection scheme for the 132 kV side of a new 400 kV/132 kV transformer (SGT8). The provision of the new transformer and protection was part of an extensive transmission system reinforcement programme that is under way for the West Midlands, as outlined in NGC's Transmission Reinforcement Instruction (TRI) 9609 of December 2000. This instruction was for "*West Midlands Development Phase-1*" and it covered "*Hams Hall 400 kV Substation and Hams Hall – Willington East Overhead Line Route*".

TRI 9609 only outlined the substation work at Hams Hall 400 kV, for the addition of six new switch bays for one Feeder (Willington East), two Skeleton Feeders (for future use), one Bus Coupler and two new Supergrid Transformers (SGT8 and SGT9). The description of the protection asset works in Section 12.7 of TRI 9609 was brief in relation to other Sections: "*Protection equipment for the Willington Circuit, bus coupler, bus section and two supergrid transformer connections is to be installed in accordance with NGTS 2.6 and the appropriate Level 3 specifications*" and it did not cover the necessary 132 kV protection work associated with the new SGT's. Details of the Hams Hall 400 kV scope of work and the 132 kV scope of work for the new Lea Marston 132 kV Substation were provided in NGC Tender Documents C/XT019 and C/XT022, respectively.

As part of the scope of work for Hams Hall, the existing 132 kV Substation was being re-engineered to become a replacement substation, on the same site, which will be named "Lea Marston" in its final form. This re-engineering of a running substation involved a complex set of intermediate and final connections for the incoming transformer circuits, with complex 132 kV bay swap-over's taking place at various stages, which affected both primary and secondary substation systems.

Both the NGC tender documents for the 400 kV and 132 kV Hams Hall work had solicited turnkey type contracts and both were subsequently released to a single Contractor. The scope of the Contractor's responsibility for the ongoing work covered "*the design, detailed design, procurement, delivery to site(s), erection, testing, commissioning, setting to work…*" of equipment. With particular reference to the protection responsibilities of the Contractor, it was a stated requirement that "*The settings to be applied to protection systems shall be specified by the Contractor and calculations shall be submitted to NGC for assessment and agreement, **not less that six months** prior to the commencement of any testing or associated commissioning activities on site.*"

The tender document statement regarding the responsibility for providing protection settings requires some clarification, in line with the Consultant's understanding of what had been NGC's policy and in response to NGC's confirmation, through subsequent correspondence discussion, via Ofgem. The NGC practice had been to make the Contractor responsible for providing settings for "unit" protection systems, where co-ordination with other protection, outside the scope of work of the Contractor, was not required and where the contractor would have access to all information required to propose settings for dependable and secure protection performance. The proposed settings would then be checked by NGC. All other protection settings would be determined by an approved NGC Settings Engineer. For SGT8 at Hams Hall, the Contractor was responsible for proposing the "unit" protection settings, such as the Transformer Differential and HV Connections differential protection, but NGC assigned the responsibility for producing settings for the "non-unit" protection, including the 132 kV protection that operated incorrectly for SGT8, to an approved NGC Settings Engineer, who was a sub-contracted Consultant.

7.2 Summary of the incident

7.2.1 Cause of the blackout

It is not necessary to repeat here all the details that led up the incident of 5 September 2003 except to concur with NGC's published report of 19 September (paragraph 19) that the blackout occurred shortly after an incorrect trip of the protection relay that had been applied to provide 132 kV Interlocked Overcurrent protection (ILOC) for the 400 kV/132 kV Transformer SGT8. The relay tripped the 400 kV and 132 kV Circuit Beakers of SGT8 just 20 seconds after the 132 kV Circuit Breaker of the parallel Transformer SGT6 had been manually opened, under local control, with permission from the NGC Control Centre. This action was to address a serious secondary system problem that had been observed by NGC staff for the recently re-commissioned SGT6. After SGT8 was incorrectly tripped by protection, the 275 kV/132 kV Transformer SGT3 was left supporting the Hams Hall 132 kV load in isolation. The load on SGT3 reportedly rose to 319 MVA, but its rating is only 120 MVA. At 266% of rated load and with the NGC transformer back-up protection typically set to pick up at 145% of rated load current, it was certain that the first-stage of the SGT3 Back-Up Overcurrent protection would soon operate to trip the SGT3 132 kV Circuit Breaker. This correct protection operation occurred approximately 15 seconds after the incorrect SGT8 trip, with the result that all load was the lost at Hams Hall 132 kV substation.

After SGT6 had been unloaded, the 132 kV load current for SGT8 had increased from approximately 630 Amps to around 1000 Amps. Although the setting of 132 kV ILOC protection was intentionally and by requirement set below the full load current of its associated transformer (420 Amps setting compared to 1050 Amps full load), the operation of the SGT8 protection relay was incorrect, since the ILOC protection should be interlocked with 132 kV busbar protection trip relay operation. The protection should not be armed unless the busbar protection trips. In this case, there was no operation of the busbar protection or any of its trip relays and so the ILOC protection relay should not have tripped.

It was later identified by NGC that it was non-interlocked overcurrent protection functionality that had tripped. This functionality had unintentionally been left in service, on its default current settings, within the multi-functional protection relay that had been deployed to provide the required 132 kV ILOC protection for SGT8. With the applied CT ratio, the default current setting for the non-interlocked protection had been 1000 Amps primary. It has also been established that the time delay setting for the non-interlocked protection had been set to zero, which was a departure from the default setting.

In response to Consultants' question PBP013 to NGC, as to the load profile of SGT8 since it had first been loaded on 20 August 2003, 3 days after it was commissioned on 17 August, it appears that the maximum demand placed on the new transformer before the incident on 5 September had been 233 MVA, at around noon on 28 August (coincidentally 6 hours before the London incident). This would have been equivalent to approximately 1019 Amps. For the non-interlocked overcurrent protection function of the relay in question, the actual pick-up current is calibrated to 105% of the current setting, with a tolerance of $\pm$5%. The actual primary pick-up current of the protection function in question would have been centred on 1050 Amps, with possible pick-up somewhere between 1000 – 1100 Amps. Thus, the avoidance of an SGT8 trip on 28 August had been extremely marginal, although an isolated trip of SGT8 on 28 August would not have resulted in any loss of load. It appears that the trip on 5 September had also been marginal, since it took approximately 20 seconds for the protection to trip after the de-loading of SGT6, even though the non-interlocked protection in question had been set with a zero time delay.

7.2.2 Events leading up to the blackout

The day before the blackout that took place on 5 September, the 132 kV load at Hams Hall had been supported by the new 400 kV/132 kV Transformer SGT8 (240 MVA), by the 275 kV/132 kV Transformer SGT3 (120 MVA) and by two old 275 kV/132 kV Transformers SGT1 and SGT2 (2 x 120 MVA). In the evening of 4 September an existing 400 kV/132 kV Transformer SGT6 (240 MVA) was re-commissioned and put back on load, following a 132 kV bay change and some secondary system changes at the 400 kV substation, associated with the removal of the old METRO SCADA system that was being replaced by a new numerical Substation Control System (SCS). After one night with SGT6 on load, the two old Transformers SGT1 and SGT2 were taken out of service at 06:12 on 5 September, in preparation for their de-commissioning. The Hams Hall 132 kV load was then held by SGT8, SGT3 and the newly re-commissioned SGT6.

At around 10:00 on 5 September, NGC Engineers discovered smoking, burning and sparking of secondary wiring within a cubicle located in the SGT6 building at the 400 kV substation. They soon realised that the wiring was associated with some 132 kV Current Transformer (CT) circuits for SGT6 and they requested permission from National Control to temporarily de-load SGT6 and its 132 kV CT's by locally tripping the SGT6 132 kV Circuit Breaker. Permission was granted and the Circuit Breaker was opened. This action triggered the incorrect SGT8 protection operation that caused the blackout.

It was later established that the 132 kV CT wiring problem had been as a result of equipment having been removed from one of the SGT6 132 kV CT circuits, through some confusion that had arisen in connection with the METRO replacement work. A CT circuit had been accidentally cut and left open, after a transducer had been removed, without a wire link having been inserted to re-make the circuit. Leaving an operational CT circuit open while the CT is passing primary load current will result in high voltages being developed across the break and across the CT secondary windings. It is a hazardous condition, in terms of the risk of fire, or injury to engineering staff and one which might result in costly damage to a CT winding. The occurrence of such a fault would certainly require urgent attention. Once the fault had been identified, NGC and Contractor's staff on site realised that it could be safely dealt with by taking SGT6 and its 132 kV CT's off load for a short period, which was the course of action they instigated.

7.3 Scope of new protection system work associated with the incident

7.3.1 Relevant 400kV substation work

As detailed within Section 2.1.2 of NGC Tender Document C/XT019, part of the scope of work included the "*Design, supply and installation of a new micro-processor based Substation Control System (SCS) to replace the existing METRO substation remote control system which is (was) to be recovered and scrapped within the scope of works*." A modern SCS system acquires plant status and analogue voltage and current signals through "Bay Units" that are interfaced to Current and Voltage Transformer (CT and VT) secondary circuits. As required by Section 9.2.2.1, "*the location of each Bay Unit should be in the associated circuit blockhouse adjacent to the primary plant*." With the utilisation of Bay Units, any existing AC to DC current and voltage transducers for the METRO system that was being withdrawn would be surplus to requirements and so they would need to be removed as part of the contract.

In accordance with NGC Tender Documents C/XT019, the 400 kV protection systems for existing plant (including the 400 kV/132 kV transformer SGT6) were to be retained. New protection systems were only required for new plant, which included the 400 kV/132 kV transformer SGT8. In accordance with NGC requirements and since the 132 kV switchgear was remote from the 400 kV substation, through approximately 1km of intervening 132 kV overhead line, the required 132 kV protection scheme for SGT8 included "Unit Protection", based on differential current relays, with optical fibre communication between them. One of the 132 kV differential relays had to be located in a relay cubicle at the 400 kV substation, together with the 132 kV back-up earth fault protection that was also required. The other differential relay had to be located at the 132 kV substation, along with the specified "Non-Unit" Interlocked Overcurrent protection (ILOC). The required arrangements were summarised in the protection schematic diagram with Tender Document C/XT019 and an extract from this is given in Figure 24, with the required 132 kV ILOC protection function highlighted.

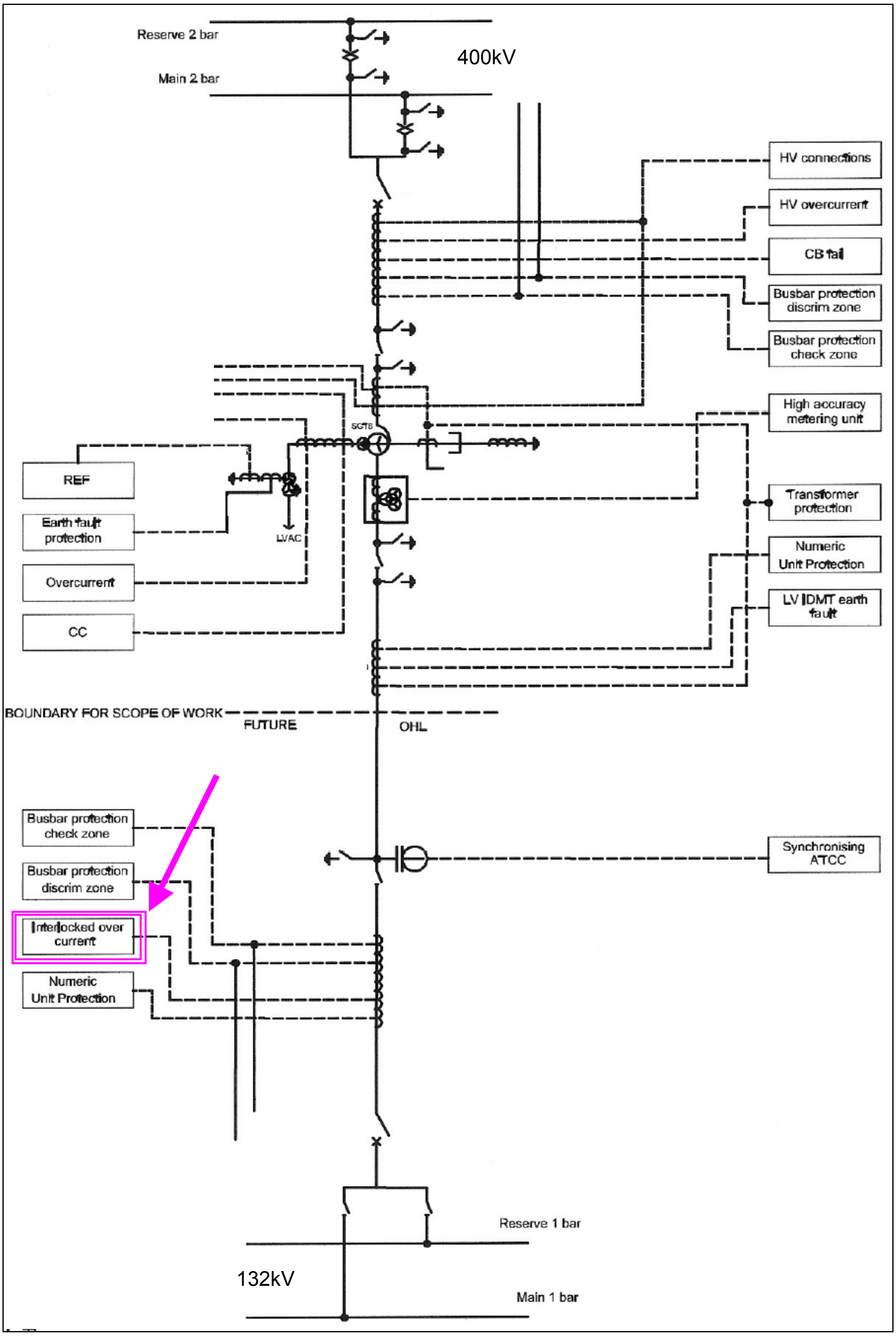


Figure 24 – Extract from NGC Tender C/XT019 Drawing 29/25395 for SGT8

7.3.2 Relevant 132kV substation work

As detailed in the introductory section of NGC Tender Document C/XT022, the required work was to construct a new 132kV substation (Lea Marston) to replace the old Hams Hall 132kV Grid Supply point, within the curtilage of the old substation. The work would be part of NGC's "West Midlands Development". NGC would have ownership of the new substation, but two DNO's (EME and Aquilla) would retain operational control of circuit breakers for their feeders. During the construction work and as alluded to in NGC's own incident investigation report, there was a need to swap the existing SGT6 incoming supply circuit between its original 132kV bay and what had been the SGT7 bay and then the old SGT6 bay would be modified to accommodate the new SGT8. Such swapping of plant bays had added to the complexity of the protection and control work for the Contractor. Some of these aspects are detailed in the scanned extract from the NGC Tender Document C/XT022 given in Figure 25.

8.2.1.1 SGT6, 7, 8 & 9 132kV

The proposed 132kV connections and protection are shown on drawing 29/8680. The above mentioned circuits will change position during site construction works as indicated in the attached proposed stage by stage drawings. The new relay panel suite should be laid out as required by the final substation arrangement. During site construction rewirings, including multicore cable work, of these relay panels will be required as the controlling circuit breaker position changes.

Work will be required at the 400kV site associated with SGT 6&7 including replacement intertrip equipment and re-testing of existing equipment to meet the requirements of the following specification.

The protection panels shall be fully equipped with the following specific facilities.

The circuit will require the following protection with associated tripping and auxiliary relays, in/out switching, etc, as necessary.

Protection	SGT8 & 9 - 132kV Feeder Unit Protection with digital comms. and integral intertrip (1st). NGTS 3.6.1. SGT6 – use existing LFCB102 unit protection with integral 1st Intertrip. SGT7 – Use existing Translay unit protection.
Interlocked Overcurrent Protection	As per TPS 2.6.1 Section 11
Trip Relay Reset Scheme	To NGTS 3.6.15 requirements

Figure 25 – Extract from NGC Tender C/XT022 for SGT8 132 kV Protection

Whilst the diagram quoted in the tender extract in Figure 25 was not available for review, the text summary of the protection required at the 132 kV substation concurs with the scanned diagram from the 400 kV tender document given in Figure 24. It should have been clear to the Contractor and to NGC staff that all that was being requested at the 132 kV substation for SGT8 was the receiving end current differential relay for the unit protection and the Interlocked Overcurrent (ILOC) protection, plus some sundry equipment, but nothing more. It should have been clear from the drawing with the 400 kV tender documents (see Figure 24) that any System Back-Up protection was to be in the form of HV Overcurrent protection and LV Earth Fault protection only, with both sets of protection being located at the 400 kV substation and not at the 132 kV substation.

7.4 Explanation of Interlocked Overcurrent Protection

Through a review of contract documents and drawings made available by NGC, in response to Consultants' questions, it appears that there has been some confusion for this project between plain 132 kV Overcurrent and Earth Fault protection, as used for System Back-Up protection and Interlocked Overcurrent protection. In order to review the confusion, it is first necessary to review NGC's requirement for ILOC protection.

In accordance with NGC Technical Specification NGTS 3.24.08, "Interlocked Overcurrent" protection (ILOC) should be applied to the 132 kV side of a transmission system transformer if all the 132 kV protection Current Transformers (CT's) are located on the transformer side of the 132 kV Circuit Breaker (CB). The exception to this requirement would be for cases where 132 kV Circuit Breaker Fail protection is applied, which is not normally the case.

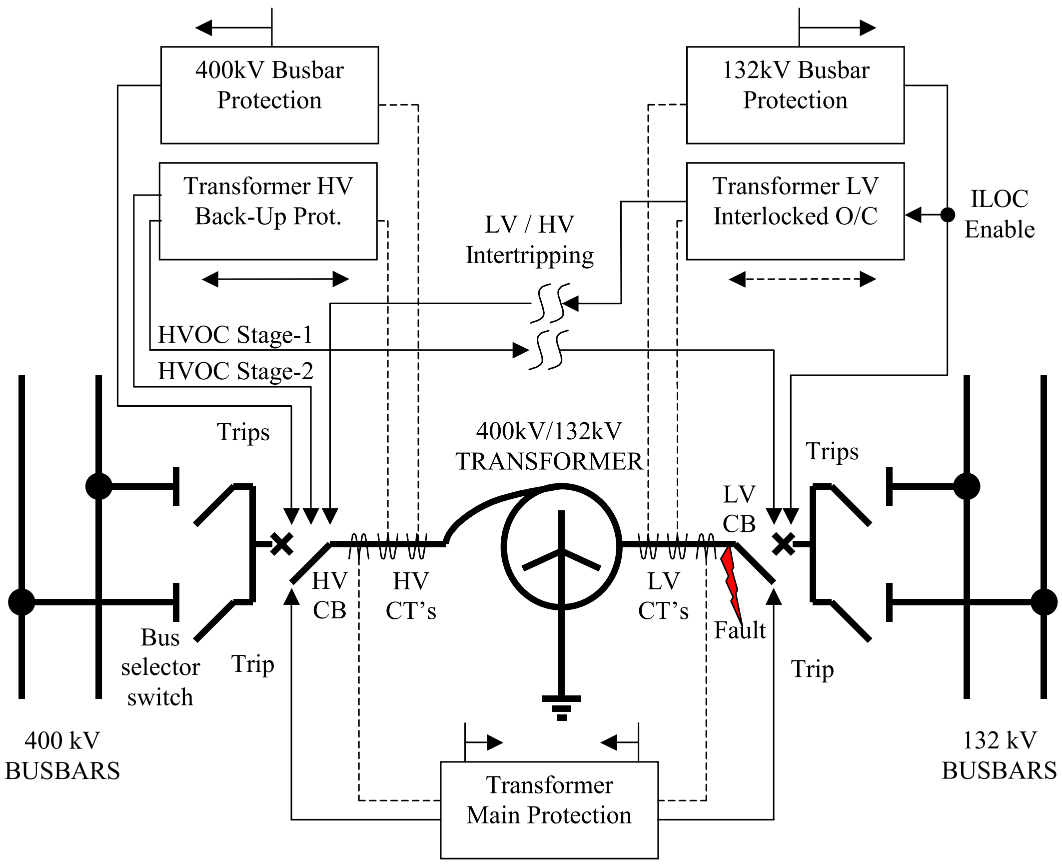


Figure 26 – Illustration of the Purpose and Application of 132 kV ILOC Protection

Figure 26 is an explanatory sketch for a 400 kV/132 kV transformer application where all the 132 kV CT's are on the transformer side of the 132 kV CB. It is a simplified sketch that does not show all the protection functions that would be provided, but which shows at least one main protection system for the busbars, "unit protection" power transformer and the "non-unit" transformer HV back-up protection. In addition, for simplicity, an intervening line between the transformer and the 132 kV substation (as at Hams Hall) has not been considered. The zone/direction of coverage provided by each set of protection has been indicated by arrows, together with trip paths and the utilisation of CT's.

As illustrated in Figure 26, it is possible that a fault (short circuit) could occur within the short zone between the 132 kV CT's and the CB. This fault would be seen within the zone of coverage of the 132 kV busbar protection, but the busbar protection is normally only arranged to trip the necessary 132 kV CB's to clear a busbar fault. There are a number of operational reasons why it would be undesirable for the 132 kV busbar protection to trip any 400 kV transformer CB's. For example, an additional tertiary winding of the power transformer, which is not shown in Figure 26, could be providing a source of AC power for the substation or it could be connected to reactive compensation equipment for the transmission system, such that 400 kV disconnection of a transformer would be undesirable when not absolutely necessary.

For the fault shown in Figure 26, the busbar protection tripping of the 132 kV transformer CB would not clear the fault current infeed from 400 kV through the transformer. The 400 kV fault current would cause the HV back-up overcurrent to pick-up, but this protection will only operate after a time delay that is set to ensure that there will be no risk of back-up protection operation during the time it would normally take to clear a 132 kV busbar short circuit. For a fault at the location shown, it is desirable to clear the 400 kV fault current infeed more rapidly than the "Stage-2" operating time of the HV back-up overcurrent protection, since a long delay in tripping would result in more extensive plant damage (especially for Gas Insulated Switchgear) and in a bigger disturbance to NGC and DNO customers, as a result of a prolonged voltage dip. It is the purpose of 132 kV interlocked overcurrent protection to provide more rapid clearance of the 400 kV infeed to a fault between the 132 kV CT's and the CB by inter-tripping the 400 kV CB

In accordance with NGC Transmission Plant Specification TPS 2.24.03, 132 kV ILOC protection should have an operate threshold equivalent to 100 MVA, in order to be sensitive enough to detect faults fed from the HV side of a transformer under minimum plant (minimum fault level) conditions, and it should be set with a relatively short operating time of 200 milliseconds. The prescribed operating threshold would typically be below the full load rating of the associated power transformer (SGT8 at Ham Hall is rated at 240 MVA). For this reason and due to the short operating time that is applied, the ILOC protection should normally be prevented from operating through some form of interlocking.

Since the 132 kV busbar protection will respond only to a busbar fault or to the type of short zone fault indicated in Figure 26, the operation of the ILOC protection is arranged to be interlocked with operation of the 132 kV busbar protection. A busbar protection trip contact should be used to arm the ILOC protection. In the event of normal clearance of a busbar fault, the ILOC protection would pick-up during fault clearance, but the fault would be cleared before the ILOC 200 millisecond time delay expires, such that the ILOC protection would not trip. In the case of a short-zone fault between the 132 kV CT's and the CB, the ILOC protection would remain picked up after 132 KV CB tripping and it would subsequently inter-trip the 400 kV CB.

Since the ILOC protection could respond to maximum transformer load current, its commissioning tests should particularly demonstrate that the protection scheme will not operate without simultaneous operation of the interlocking busbar protection relay, up to the maximum required emergency load current level for the power transformer. Since NGC Transmission Plant Specification TPS 2.24.03 requires the HV back-up overcurrent protection to be set at 145% of the transformer rated current, it would be prudent to test the LV ILOC protection for stability up to at least 145% of the LV transformer winding rated current divided by the LV CT ratio.

7.5 Some confusion about SGT 132kV Protection requirements

A pertinent extract from the Contractor's Hams Hall 132 kV DID is given in Figure 27.

Document No:PDE100159P01 Site:Hams Hall 132kV S/S Page 43

6.1.3 SGT8 – 132kV

Circuit Owner:- NGC
Fixed frame 19'', Two rear access cubicles.
Overall dimensions [each cubicle] 2200H x 800W x 600D

Cubicle 1

Feeder Protection
TPS 5/33 look-a-like
LFCB192-001A

- Feeder Protection - LFCB192
- INTERFACE [MITZ03 to be installed external to SGT8 Protection Cubicle – see item 6.1.20] – with 19'' rack mounting assembly.
- Trip Relay1 - MVAJ25
- Trip Relay 2 - MVAJ25
- Tripping Aux Relay - MVAA11
- [7] Test Module 1 - MMLG01
- Protection Switching Relay – MVAJ34
- Power Supply Supervision Relay - MVAX12
- Unstabilise Relay - MVAJ21
- [8] Test Module 1- MMLG01
- [8] Test Module 2 - MMLG01
- Switching Module - MMLZ03
- Fuses & Links to complete.

Intertripping
TPS 5/33 look-a-like
INTERTRIPPING-003

- Test Module - MMLG01
- Channel Test Module - MMLZ20
- Power Supply Relay -MVAX12
- Intertrip Receive Relay - MVAW02
- Fuses & Links to complete.

Cubicle 2

Interlocked Overcurrent Protection

- Test Module – MMLG01-A
- 3Ph O/C & E/F – KCGG142-A
- Hand/Electrical Reset Tripping Relay – MVAJ25-B (8M – 1B)

2nd Intertrip

- Dual Trip Digital Intertripping Relay – RFL9745 [mounted externally in separate Intertripping cubicle – see item 6.1.20].
- Test Module – MMLG01-A
- Channel Test Switch – MMLZ21-1
- Intertrip Relay – MVAW02-A

Trip Relay Reset Scheme

- Test Module – MMLG01-A
- Timer 1 – MVTT14-A
- S/Reset & Aux Trip [6 standard & 4 C/O contacts] – MVAA11-A
- Push Button

CB Control

- Test Module – MMLG01-A
- 6 Way Test Block for VAB – MPG2-1
- Interposing Close/Open – MVAW21
- Trip Circuit Supervision 1– MVAX31
- Trip Circuit Supervision 2– MVAX31

Figure 27 – Extract for SGT8 from the Contractor's DID for 132 kV Protection Work

With reference to Figure 27, the NGC Commissioning Panel, as part of its high level review process, would have been assured by the DID that the Contractor had acknowledged the specified requirement for SGT8 ILOC protection to be located at the 132 kV substation. However, it can also be seen from Figure 27 that the proposed type of relay offered to provide the ILOC protection function was referred to as a 3-phase Overcurrent & Earth Fault relay. This is because the protection relay being offered was a programmable, multi-function, numerical type KCGG142, where the relay manufacturer used that general form of description for the relay, even though it could be applied to provide a number of protection functions, in addition to or instead of 3-phase Overcurrent & Earth Fault protection. ✂

Two drawings related to SGT6 and SGT8 that have either been prepared by or processed by the Contractors do not show the required 132 kV ILOC protection for the SGT's, but they show plain Overcurrent and Earth Fault protection instead. These drawings are detailed as follows:

Table 1 – Summary of Hams Hall SGT6/8 Drawing Discrepancies

Drawing Number	Title	Comments
NGC Drawing 42/72953 - Rev.B 07/02/03 revised by Contractor in Line with new 400kV SCS requirements, original was 24/02/93	400/132kV Substation Block Diagram - Main Protection & Connections **SGT6**	This does not show ILOC protection at 132kV, but 2O/C + E/F protection
Contractor's Drawing for NGC T1/42/152117 – Rev.A 12/05/03	Circuit Diagram CT/VT Connections **SGT8**	This shows SGT8 in to ex-SGT6 Bay. Drawing does not show ILOC protection at 132kV, but 3O/C + E/F protection

It is not clear what the source of confusion has been. ✂

Whatever was the source of the confusion here, the scheme engineered by the Contractor for SGT8 ILOC protection and which was based on the KCGG142 multi-functional numerical (refer to Figure 5 and Figure 6), was not directly in accordance with NGC's specified requirements and this added further to the confusion.

7.6 Review of the contractor's protection scheme for SGT8 132kV

7.6.1 Scheme drawing

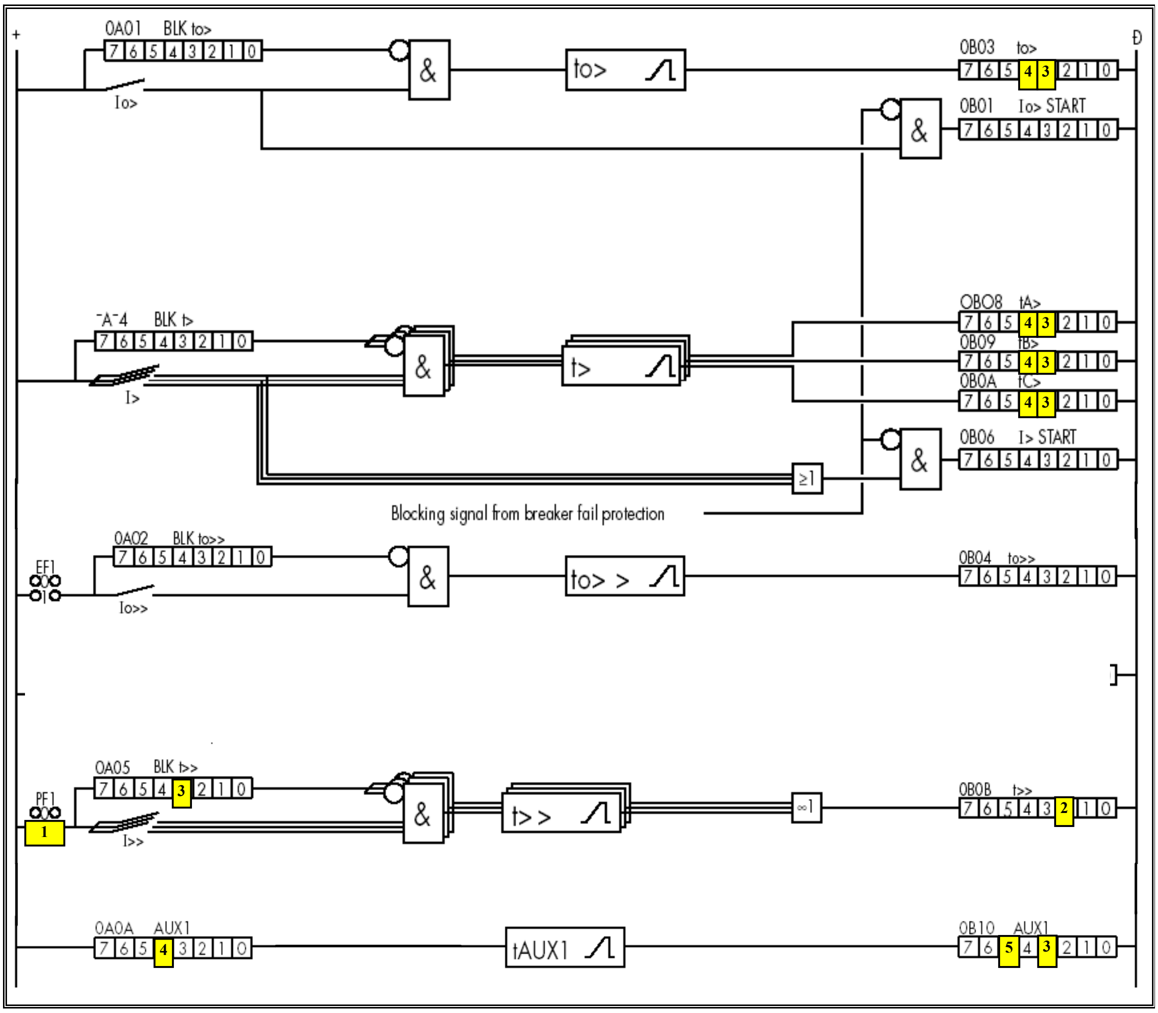
The protection scheme offered by the Contractor to fulfil the 132 kV protection requirements for SGT8 is summarised by drawing number T1/42/152119, which has the title of "Circuit Diagram 3 Phase Overcurrent and Earth Fault Protection". This title alone should have highlighted to the NGC Commissioning Panel, which comprised NGC and Contractor's personnel, that there had been some confusion on the part of the Contractor about actual protection requirements, given the fact that the protection actually required was just ILOC protection.

Through the Consultant's review of Commissioning Panel meeting minutes, it is clear that a separate Commissioning Panel had been set up to deal with the 132 kV work at Hams Hall/Lea Marston. The fact that the NGC Commissioning Panel did not identify the inappropriate protection scheme that had been engineered by the Contractors may be an indication that some of the NGC and Contractor's staff involved did not fully appreciate the precise nature of the protection function that was actually required.

7.6.2 Scheme design

The protection scheme provided by the Contractor was summarised by their drawing number T1/42/152119. This has been reviewed by the Consultants and, through the scheme wiring and the I/O configuration settings listed on the scheme diagram for the KCGG142, it had clearly been engineered to provide non-interlocked, time delayed overcurrent and earth fault protection, as a base function. This was termed "System Back-Up" (SBU) protection in the drawing, in accordance with NGC parlance. The scheme had also been engineered to provide supplementary ILOC functionality, but the only references given in the drawing for trip and alarm output contacts were 3O/C + E/F and SBU (System Back-Up).

Figure 28 is a distillation from the KCGG142 service manual, by the Consultants, of relevant protection element functionality for the 132 kV protection scheme that had been engineered by the Contractors. The Input and Output "Mask" settings that had been applied to the relay, in accordance with the Contractor's drawing number T1/42/152119, have been shaded in Figure 28. The additional overcurrent protection elements I>> + t>> were enabled via the PF1 Function Link setting and they were used to provide the ILOC protection function. With reference to Figure 29, which shows the scheme wiring external to the KCGG142 relay, a normally closed Busbar Protection Trip Relay (BBTR) contact energises opto isolator input 3 when the BBTR is not operated. Figure 28 shows that the blocking input mask for the I>> protection function is set to respond to opto input 3 being energised and hence to non-operation of the BBTR. This provides the interlocking for the ILOC protection. For some reason, instead of using the t>> adjustable timer to provide the required ILOC delay of 200 milliseconds, the t>> was intended to be set to zero and the I>> + t>> protection function was arranged to operate output relay 2 without delay.



Legend:

I>	= Phase overcurrent base element start	t>	= Phase overcurrent base element timing
Io>	= Earth Fault base element start	to>	= Earth Fault base element timing
I>>	= Phase overcurrent additional element start	t>>	= Phase overcurrent additional element timing
Io>>	= Earth Fault additional element start	to>>	= Earth Fault additional element timing
		tAUX1	= Auxiliary timer function

Figure 28 – Summary of Contractor's 132kV Protection Scheme Logic Configuration

With reference to Figure 29, the contact of output relay 2 was wired to initiate opto-isolator input 4 and, with reference to Figure 28, this opto-isolator was set to initiate the scheme timer tAUX1, as determined by its input mask setting. Timer tAUX1 was to be set to 200 milliseconds to provide the required ILOC protection time delay and tAUX1 was configured to operate output relays 3 and 5, via the tAUX1 output mask settings. It can be seen from the scanned extract of Trip and Alarm outputs from the Contractor's diagram in Figure 30, that output relay 3 is used to initiate the Back-Up protection Trip Relay (BUTR). Contacts of this relay were wired to initiate SGT8 132 KV Circuit Breaker tripping and intertripping of its 400kV Circuit Breaker. The relay 5 contact was used to initiate an alarm, but it can be seen from Figure 30 that the Contractor had named the alarm function "SBU EARTH FAULT PROT." Rather than "ILOC protection".

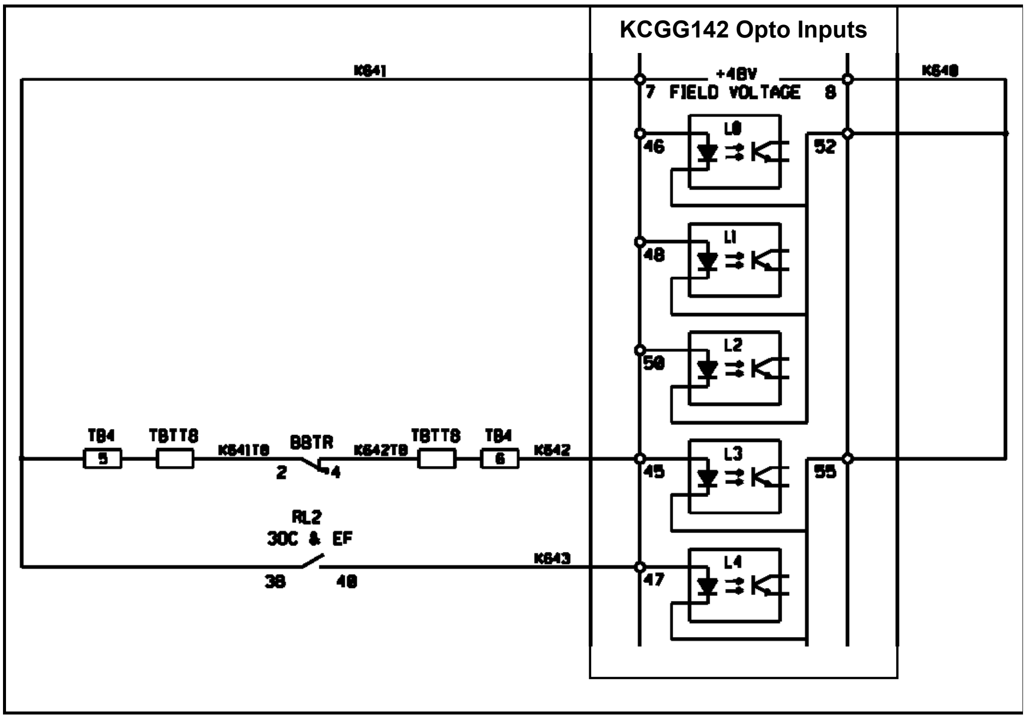


Figure 29 – Summary of Contractor's Protection External Scheme Wiring

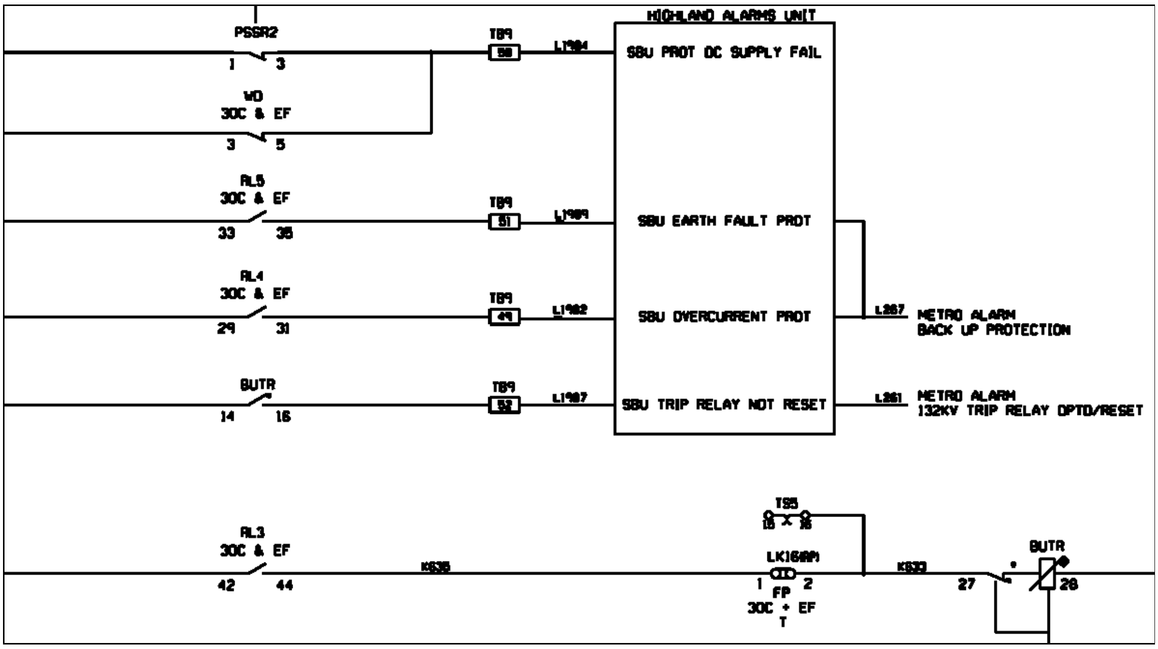


Figure 30 – Summary of Contractor's Protection Scheme Alarm + Trip Outputs

It can be seen from Figure 28 that there is no setting facility within the KCGG142 relay to disable its I> + t> and Io> + to> Overcurrent and Earth Fault base elements - other than to permanently energise an opto isolator to block the elements. It can also be seen that the Contractor had intended that these protection elements should operate output relays 3 and 4. With reference to Figure 30, it can be seen that the non-interlocked base protection elements would initiate the BUTR relay operation via relay 3 contact operation and an alarm via the relay 4 contact.

In summary, it appears that the Contractor had not fully appreciated NGC's specified requirements for the provision of ILOC protection only and the protection scheme that they designed and delivered was not entirely appropriate for the application, as could readily be determined by a quick review of the scheme drawing that had been provided.

As noted in the preceding scheme design review, the ILOC functionality requires a normally closed Bus Bar protection (BBP) trip relay contact to disable the ILOC protection when the BBP trip is not operated, rather than the expected N/O trip relay contact to enable the ILOC protection when the BBP operates. This aspect was raised as an item of concern in an internal e-mail sent by one of NGC's Engineers to another, just 3 days before the East Birmingham power failure on 5 September. A scanned extract of the e-mail is provided in Figure 31. This concern it raised was very astute and quite valid. However, by suggesting that the ILOC protection current setting might be raised as a solution, it appears that at least one of NGC's staff involved with the delivery of the new protection systems did not fully appreciate the NGC application and setting policy for ILOC protection.

SGT8 LV interlocked overcurrent.

This is situated on the 132kV relay panel and is a "K" series relay. Its setting is 420A (less than load current) but being an interlocked overcurrent its operation is restrained by a Bus Zone trip relay contact situated on the Bus Zone relay panel.

This restraining contact is a "normally closed" contact. This is what concerns me, I just know this is a fault waiting to happen ie. Vibration, removing isolation links, removing the relay, Bus Zone maintenance etc.

Q.

Why does it need to be normally closed?

Why does the setting need to be slow low?

Could we not raise the setting to above normal load current to prevent a future mal op?

Figure 31 – Scanned Extract from NGC e-mail to Contractors dated 02/09/03

With reference to schematic drawing T1/42/152120 covering intertripping, the Contractor had also incorrectly engineered SGT8 intertripping arrangements from the 132 kV substation to the 400 kV substation, whereby operation of the 132 kV busbar protection would intertrip the 400 kV SGT Circuit Breaker. This unwanted arrangement actually negated the need for ILOC protection. Having subsequently identified this arrangement to be an error, the Contractor brought it to NGC's attention on 29 August 2003, after SGT8 had been in commission for 12 days and on load for 9 days.

7.7 Review of NGC Settings Engineer actions

The requirements for authorisation and the role of a Settings Engineer are set out in NGC Transmission Procedure TP107. The procedure for determining relay settings is given in the scanned extract from TP107 in Figure 8.

The 132 kV ILOC protection for SGT8 is classed as "non-unit" protection. As already clarified in the last paragraph of Section 7.1, the setting calculations for the SGT8 ILOC protection scheme were performed by an approved NGC Settings Engineer, under sub-contract to NGC. A scanned extract of the Engineer's setting calculations is provided in Figure 32. It can be seen that only general settings appropriate to the ILOC protection were determined, without identifying how specific parameters of the KCGG142 protection relay had to be set. For example, the ILOC current setting parameter referenced "I_S" in the calculations is not actually a valid parameter for the KCGG142 relay that had been applied in the Contractor's protection scheme and so it was not clear from the setting calculations which of the three overcurrent elements of the relay had to be set for ILOC protection. This would have been understandable if the NGC Settings Engineer had simply performed general calculations, before the Contractor's scheme details had been issued, but this was not the case. The Contractor's scheme drawing was issued on 12 May 2003, but the NGC Settings Engineer calculations were performed 4 months later, on 12 August 2003.

Substation: Hams Hall 132kV **Circuit:** SGT 8

Protection
LV Interlocked Overcurrent Protection (KCGG142), LV Synchronising (KAVS100)

Data

System voltage: 400/132kV
CT Ratio: 1000/500/1

Policy (TPS 2.24.3)

"Interlocked overcurrent protection function with definite time characteristic
i) Current range: 420 – 450A, preferred setting 432A
ii) DT time lag: 200ms

Note: Interlocked overcurrent relays are normally located on the 132kV side of 400/132kV or 275/132kV Supergrid transformers. 132kV systems are not normally equipped with Circuit Breaker Fail protection; Interlocked Overcurrent is a substitute for Circuit Breaker Fail Protection. A setting of 100MVA is considered to be sensitive enough to detect faults fed from HV side under minimum plant condition."

Calculation

$$\frac{432}{1000} = 0.43\text{ A}$$

KCGG settable to 0.42 A secondary = 420 A primary

Choose Is = 0.42 A

Choose DTL characteristic to give operating time of 0.2s.

Summary – KCGG142

Is = 0.42A (420A, 96MVA)

Characteristic = DT

Figure 32 – Scanned Extract of Setting Calculations for SGT8 KCGG142 Protection

Irrespective of the level of detail in the setting calculations document, detail is essential when it comes to compiling the NGC MARS settings sheet for a protection relay, since the MARS sheet is the definitive and authorised record of how actual relay parameters must be set for service. As indicated in Section 6 of the TP107 extract given in Figure 8, a MARS sheet must be completed by an NGC Settings Engineer for each protection relay. In this case, it was the subcontracted approved NGC Settings Engineer who was responsible for compiling the MARS sheet for the ILOC protection and from the scanned copy of the sheet, it appears to have been compiled at the same time as the setting calculations were performed on 12 August 2003.

Following the Consultants review of the MARS sheet for the KCGG142 relay provided for ILOC protection, it is clear that there was a failure by the approved NGC Settings Engineer to prescribe settings that would effectively prevent the non-interlocked overcurrent and earth fault protection functionality of the Contractor's scheme from interfering with system operation and normal system fault clearance. In particular and with reference to Figure 28, there was a an omission to cancel the relay 3 and relay 4 selections from the t> and to> output masks in order to disable tripping by the non-interlocked overcurrent and earth fault protection elements and there was a failure to set the protection element current and time settings to maximum, to prevent unwanted protection alarms. It appears that the Settings Engineer transcribed the inappropriate output mask settings indicated in the Contractor's scheme drawing. The MARS sheet also inappropriately prescribed the operating time delay (t>) for the non-interlocked overcurrent protection to be definite time and to be zero and the setting parameters for the earth fault protection elements were not even listed.

NGC has confirmed that the complete ILOC protection scheme information had been provided to the approved NGC Settings Engineer. Furthermore, NGC stated that discussions had taken place between the scheme supplier and the Settings Engineer to facilitate understanding of the relay logic proposed by the supplier. It is not clear, therefore, why the MARS sheet errors and omissions were made or why the Settings Engineer did not highlight the fact that the proposed scheme was not entirely appropriate, with its inclusion of non-interlocked protection functionality that was not specified, with the scheme drawing title referring to overcurrent and earth fault protection (non-interlocked) and with the SBU (non-interlocked) terminology used in the drawing. The Engineer had, however, recognised that the non-interlocked base overcurrent (I>/t>) and earth fault (Io>/to>) protection elements were not required, since the term "not used" had been entered against their setting parameters in the MARS sheet. However, the term "not used" is not an available setting for any of the relay parameters and so it was not acceptable to use such a term for the MARS sheet. ✂

When considering timescales for settings and commissioning activities in Section 7.8.2, there is some indication that the provision of relay settings had, for reasons unknown, become the critical path for SGT8 commissioning. ✂

With settings applied as listed in the NGC MARS sheet, the non-interlocked overcurrent and earth fault protection elements of the relay had actually been enabled. The non-interlocked I> overcurrent protection threshold setting was not defined in the MARS sheet (simply stated as "not used"), so it appears to have been left at its factory default setting of 1.0 x I_n, which was equivalent to 1000 Amps primary. The t>/DT Definite time parameter was set to zero (again with a meaningless "not used" annotation). With the relay t> curve selection set at Definite Time (DT), the zero second t>/DT setting would have been active. The non-interlocked earth fault protection settings were not detailed on the MARS sheet, so it is assumed that they were left at the default settings equivalent to 200 Amps primary with a definite time delay of 100 seconds.

✂

In consideration of the MARS sheet portrayal of settings, the use of a pure text-string format may not be entirely inappropriate for dealing with the range of setting parameters and options offered by the proliferation of multi-function numerical relays, such as the KCGG142. For the future, it may be better to transcribe the typical tabular summaries that manufacturer's provide for all available relay setting parameters, with their setting ranges and steps stated and with space for the proposed setting value to be entered in each case. Any settings that are not relevant could be scored out.

7.8 Review of ILOC protection commissioning for SGT8

7.8.1 Review of commissioning procedure and documentation

Although the KCGG142 relay is Type Registered by NGC and applied elsewhere on its network, it appears that not all the required support documentation, under Type Registration rules, had been provided by the manufacturer prior to commissioning. In particular and with reference to the extract from TP106 in Figure 17, there was no approved Site Commissioning Test (SCT) document template for the relay, so the Contractors used their own document, based on the relay manufacturer's service manual. Whilst their document might be adequate for plain overcurrent and earth fault protection applications, it was inadequate for proper commissioning of the SGT8 ILOC protection scheme. When the Contractor's test document was first reviewed by the Consultants, it was presumed that it covered purely pre-checks/functional checks, but NGC confirmed, at a meeting held at Hams Hall on 17 October that there were no other test records.

In correspondence discussion, via Ofgem, NGC subsequently stated its view that the use of the manufacturer's own commissioning test sheet, being derived from the service manual of the Type Registered relay, was adequate to check the general functionality of the relay type. However, NGC recognised that the sheet does fall short for testing particular applications of the relay such, as an Interlocked Overcurrent protection function. The sheet had not been formally registered by NGC as an SCT document for the relay type. Even for testing the general overcurrent and earth fault protection functionality of the relay, the Consultants presume that NGC's preference would still be for its standard procedure SCT 20.5.3 to be applied, rather than the contractor's procedure.

A scanned extract from the Contractors KCGG142 ILOC test record for SGT8, which covers setting verification, is provided in Figure 33. The completed test record sheet was signed only by the Contractor's Commissioning Engineer and it was dated 16 August 2003, which was the day before SGT8 was commissioned. The test record under discussion relates to Stage-1 tests under the requirements of NGC Transmission Procedure TP106, for Equipment Commissioning and Decommissioning. Under TP106 (see extract in Figure 17 in Section 6.6.1), at the discretion of the Commissioning Panel, it may not be necessary for

Stage-1 tests to be witnessed. Such agreements would be documented in the Commissioning Programme, but a copy of such a document was not provided with the information requested under Consultants' question PBP025. By comparison, a copy of the Plan for Wimbledon had been sent. In response to Consultants' question PBP60, NGC stated that they witnesed the Stage-2 tests for the ILOC protection.

It can be seen from Figure 33 that a very rudimentary test of the operation of the I>> current detector element used for ILOC protection was performed. As detailed in Section 7.6.2, the time delay t>> associated with the I>> element was set to zero and, for some unknown reason, the auxiliary timer tAUX1 had been used to provide the ILOC protection time delay in the protection scheme that had been supplied by the Contractor. The single test that was performed was to inject the relay at a current exactly equal to the I>> pickup setting and to check that the I>> element operating time was close to zero.

Setting Verification Tests

Customer's settings applied?		Yes/~~No*~~
If settings applied using a portable computer and software, which software version was used?	N/A	
Settings on relay verified?		Yes/~~No*~~
Protection function timing tested?		Yes/~~No*~~
Function tested?		t>>/~~to>~~
Polarising voltage (KCEG relays only)		V/na*
Characteristic angle (KCEG relays only)		°/na*
Operating boundary 1 (KCEG relays only)		°/na*
Operating boundary 2 (KCEG relays only)		°/na*
Applied current	0·42	A
Expected nominal operating time	0·0	s
Actual operating time	0·09	s

Figure 33 – Scanned Extract from SGT8 KCGG142 Commissioning Record 16/08/03

As a minimum, the Consultants would have expected tests to have been conducted at above and below the I>> threshold setting, to verify the setting and that tests should also have checked the ILOC scheme operating time through tAUX1. Additional tests should have been conducted to check the interlocking action of the Bus Bar protection Trip Relay contact. The tests that were actually performed were clearly inadequate.

In the absence of a Commissioning Programme document, as demanded by NGC's Transmission Procedure TP106, and without any NGC test witness signatures on the ILOC protection test record, it is not possible to determine whether or not the Commissioning Panel had approved the test procedure that the contactors had used. The absence of a Commissioning Programme document is a matter of concern, which raises a question as to the quality of the commissioning management by the Commissioning Panel.

The erroneous enabling of non-interlocked overcurrent protection within the multi-function KCGG142 relay and its undue restriction on SGT8 loadability would only have been highlighted if a loadability test had been applied to the protection scheme to confirm that the transformer could be loaded up to its emergency rating without any protection element issuing an unwanted trip. Such testing is not yet widely applied by other TNO's worldwide, but some testing of this form is recommended by the Consultants for the future, when commissioning multi-function relays like the KCGG142.

7.8.2 Timescales for Settings and Commissioning

With reference to Consultants' questions PBP026 and PBP027, copies of the Contractor's planned and actual time charts were provided and pertinent scanned extracts have been included in Figure 34 and Figure 35, respectively. From the actual record, it can be seen that SGT8 was energised on 17 August 2003. Based on NGC loading records for SGT8, which were supplied in response to the Consultants' question PBP013, the transformer was first put on load on 20 August 2003.

With reference to the original plan, the SGT6(SGT8) outage had been expected to end on 9 July 2003 and so there would have been some pressure to end the outage by the time the ILOC protection commissioning tests were performed. The date for the SGT8 132 kV ILOC protection commissioning record was 16 August, which was the day before transformer was first energised, even though the 132 kV protection installation work had apparently been completed on 20 June 2003; in 3 days rather than the originally planned 15 days.

It is not clear why there was such a long interval after protection installation before the ILOC protection commissioning tests were performed, but is noted that the issue of the ILOC protection settings calculation and the MARS sheet for the KCGG142 relay had been on 12-13 August, which was just 3 days before commissioning tests took place.

544	**5.3.5 SGT6 becomes SGT8 (Section C)**	**4 wks**	**16/06/03**	**11/07/03**
545	5.3.5.1 Outage: SGT6	18 d	16/06/03	09/07/03
546	5.3.5.2 Install new SGT LV protection	15 d	16/06/03	04/07/03
547	5.3.5.3 All labels to be changed	5 d	23/06/03	27/06/03

Figure 34 – Extract from Contractor's Originally Time Chart

786	**SGT6 becomes SGT8 (Section C)**	**100%**	**46 d**	**16/06/03**	**17/08/03**
787	Outage: SGT6	100%	46 d	16/06/03	17/08/03
788	Install new SGT LV protection	100%	3 d	18/06/03	20/06/03
789	All labels to be changed	100%	1 d	25/07/03	25/07/03
790	Database modified	100%	1 d	18/06/03	18/06/03
791	Energise SGT8	100%	0 d	17/08/03	17/08/03
792	Take Over (Section C)	100%	0 d	17/08/03	17/08/03

Figure 35 – Extract from Contractor's Actual Time Chart of 19/08/03

In a meeting at Hams Hall on 17 October, NGC verbally informed the Consultants that the working hours of the Contactor's staff and their own staff are required to be monitored and that no one is permitted to exceed the rules of the EU Working Directive. They further stated that the use of "Shift Commissioning" is never planned because it results in lack of continuity and that "Shift Commissioning" had not been practiced for the Hams Hall work.

Examination of the Contractor's timesheets shows that three of the four commissioning engineers had worked, on average, between 50 to 60 hours per week (with the fourth engineer averaging just over 40 hours per week) over the five weeks prior to the Hams Hall incident. Given the nature of commissioning work, the Consultants do not regard this as excessive, where the adoption of flexible working hours is essential to get the job done, and at certain stages in the commissioning programme it may be necessary for engineers to work well in excess of the 48 hours per week average laid down in the EU directive. ✂ In NGC's response to questions and comments on this topic they have emphasised that the commissioning process is one of intense activity, interspersed with periods of waiting for the appropriate system conditions to allow work to proceed directly on the transmission system. NGC has also indicated in its response on this topic that their site staff are supported by a range of specialist engineers who spend significant time on site during the commissioning period. It is accepted from NGC's statement that they do take their responsibilities for a safe and healthy workplace seriously ✂.

NGC has confirmed that different commissioning teams were involved in the two incidents with SGT6 and SGT8.

7.8.3 Commissioning engineer authorisation

The Contractor's Commissioning Engineer would undoubtedly have been vetted and approved by the NGC Commissioning Panel that had been created for the project. The verbal reports given by NGC at the meeting held with the Consultants on 17 October were that he was well regarded and experienced. However, it seems that after his formal interview, he apparently admitted to having experienced some confusion during the commissioning of the ILOC protection. The Contractor's identification of the apparent 132 kV Busbar Protection intertripping error for SGT8 may have followed internal discussion after feedback from the Contractor's Commissioning Engineer, regarding the ILOC protection.

7.9 Interlocked overcurrent protection remedial action for SGT8

The Consultants have reviewed the revised MARS sheet for the protection and it is clear that the non-interlocked overcurrent and earth fault protection functions are no longer assigned to any output relays and their current and time settings have been set to maximum to prevent them operating during system faults and disturbances to cause misleading alarms.

Regarding the undesirable use of a normally closed Bus Bar Trip Relay contact to block the ILOC protection, the Consultants were advised by NGC that the Contractors were working on a scheme redesign to address this issue, for later implementation.

7.10 Review of the SGT6 open circuit CT event

7.10.1 Events leading up to the error

It was important to review the open circuit CT situation that arose, since it necessitated the emergency switching actions that precipitated the incorrect SGT8 trip and then the blackout of 5 September 2003.

In the week following the incident, on 11 September, a Protection and Control Design Review Meeting was held between NGC and the Contractors, which was chaired by a senior NGC expert. A copy of the meeting minutes was made available by NGC in response to Consultants' question PBP025. A pertinent section from the minutes has been transcribed in Figure 36, but with the Contractor's name excluded.

	Situation	Action
11	**Site Access Control**	
11.1	The incident was caused by a Contractor's wireman being given access to a cubicle, only to find that there was wiring existing in the cubicle – but not on the drawing – this included the CT and transducer installation. The wireman alerted the Contractor's supervisor and commissioning engineer, who told him that the wiring was redundant and only needed to be tidied up. In doing so, the CT was cut.	(a) Wireman's method statement was to work to the drawings – when the panel did not accord with the drawings the panel ought to have been fully researched by the commissioning engineer, with the Contractor's supervisor modifying the method statement. (b) Above action agreed at review and also requires elevating to investigation team for action

Figure 36 – Scanned Extract From Minutes of P&C Design Review Meeting 11/09/03

With the presumption that both NGC and the Contractor had approved the minutes and the frankness of the details in Figure 36, they are probably the most accurate initial account of what led up to the open circuit CT incident.

The circumstances of the open circuit CT incident were discussed at a meeting between the Consultants and NGC representatives during a visit made to Hams Hall Substation on 17 October. In line with the extract from the meeting minutes of 11 September, given in Figure 36 and items 65 to 68 of NGC's incident report of 19 September, it was confirmed that the open circuit CT incident had been precipitated by the fact that a site drawing for a panel was not in accordance with the as-built status of the panel, due to the fact that there was some wiring and equipment in the panel that was not shown on the drawing. Unusually, it appears that the site drawing had got ahead of the actual status of equipment on site. Usually, it is more common for drawing discrepancies to be the result of drawings not having been kept up to date with the status of equipment on site. In this case, it appears that the contractor for some previous work had updated a panel wiring diagram to show its intended status after the removal of some redundant wiring and equipment, but the wiring and equipment had not actually been removed.

With reference to the meeting minutes of 11 September, to NGC's incident report of 19 September and to the Consultants' meeting with NGC at Hams Hall on 17 October, there is some confusion as to whether the Contractor's wireman and/or Commissioning Engineer appreciated that an operational 132 kV CT circuit would be cut or interfered with when it was agreed with NGC that the redundant wiring and equipment should be removed to allow the planned new DCS interfacing work to proceed in the panel. In correspondence discussion with NGC, via Ofgem, NGC's account is that the contractors reviewed the situation on site with NGC staff. Their wireman was subsequently advised to remove some of the redundant wiring and equipment that was not shown on the drawing to make room for the new SCS wiring. This was apparently on the understanding that the wiring to be removed was not associated with any CT circuits. Due to the complexity of the operation, the Contractor's Commissioning Engineer carried out the removal of the redundant wiring himself. It was during his work that 132kV CT circuit wiring was cut.

From all three sources of information, it is clear that there were failures of both NGC staff and the Contractor's staff to have had the drawing discrepancy properly researched before embarking on equipment removal. Thus, it is not clear whether the open circuit CT arose out of ignorance of the fact that an operational CT circuit would be cut or whether there had been an accidental failure to ensure that, when such a circuit was cut, it would be remade via a wire link. It is understood from NGC's verbal account of an early post incident discussion with the Contractor's Commissioning Engineer, that he had quickly realised what had happened.

7.10.2 How the operational problem was rectified

The open-circuited CT was located within the yellow phase transformer 132kV bushing turret and it drives the 132 kV Overcurrent & Earth Fault protection. Once the transformer was off-loaded the 132kV CT would not have been subject to load or transformer magnetising currents, so it would be possible to deal with the problem as long as certain safety precautions were taken to allow for the very small probability of a 132 kV short circuit fault developing during the remedial work, where the open circuit CT might suddenly see a high primary current.

The discovery of the open circuit CT and the safe procedure for repairing the faulty CT circuit, with the transformer off-load, is described below as follows, with the aid of photographs and explanatory diagrams provided by NGC.

NGC has stated that, due to the circumstances at Hams Hall on 5 September 2003, the CT and associated wiring was not checked for possible damage before it was returned to service on 5 September 2003. However, a week later, SGT6 was apparently taken out of service and the CT was tested according to procedure SCT sheet 20.1 – Current Transformers Magnetisation Tests and the secondary wiring was subjected to Insulation Resistance tests in accordance with SCT sheet 20.4.1. All tests proved satisfactory.

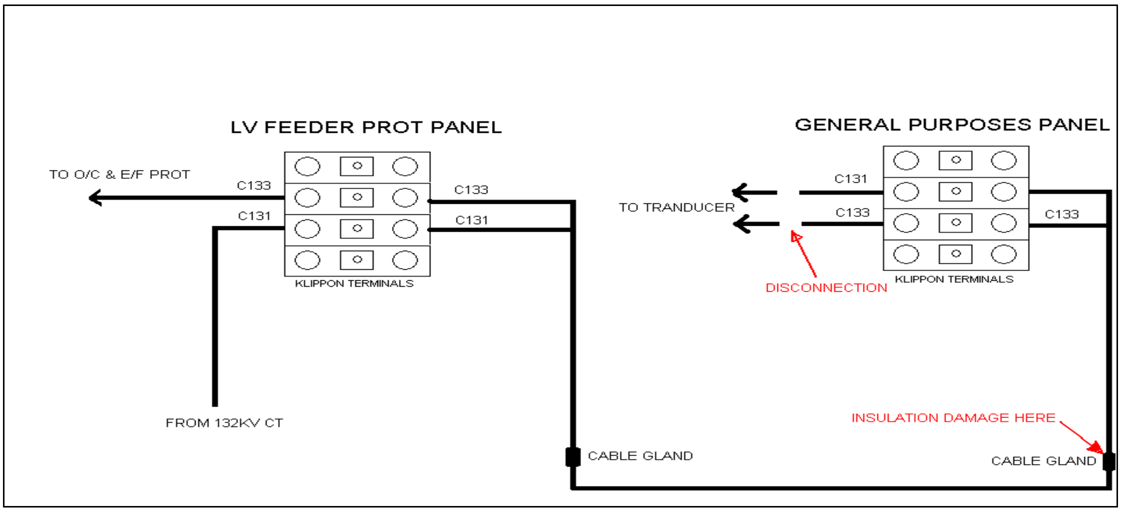
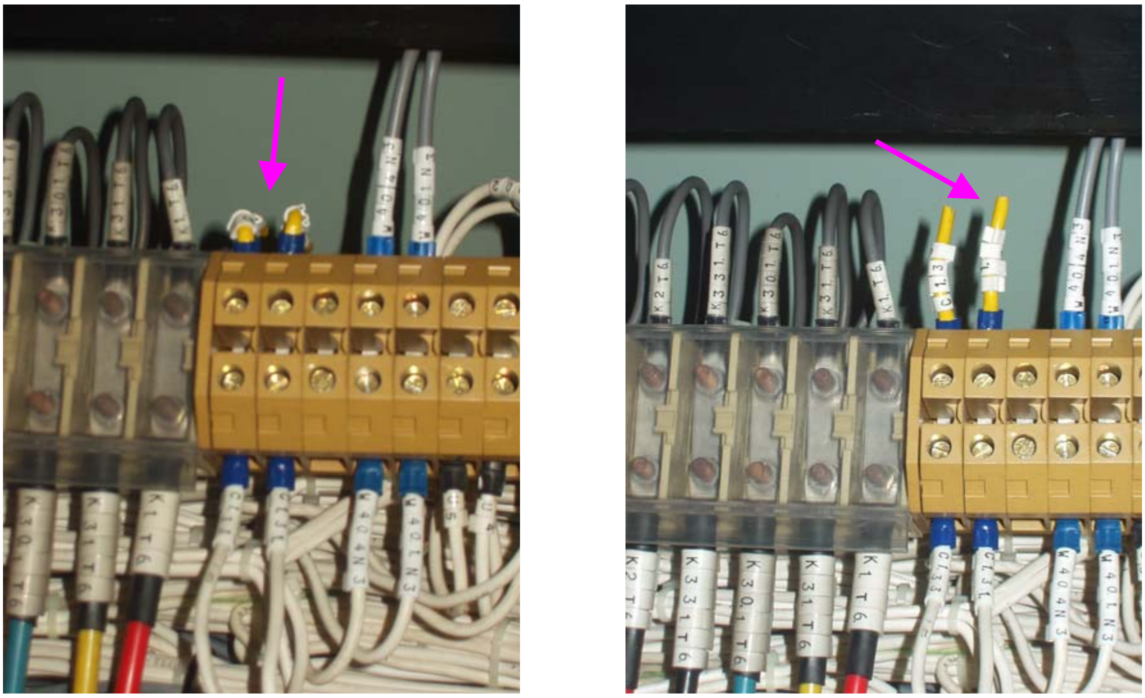


Figure 37 – Initial Situation as Found

With reference to Figure 37, cable damage (burning insulation) was discovered in the General Purposes relay panel at a gland. When this cable was identified, it became apparent that wires C131 & C133 were open circuit.



a) Wiring as found with problem not visible **b) Wiring after problem exposed**

Figure 38 – Views of the Cut 132kV CT Circuit Wiring in the SGT6 400kV Relay room

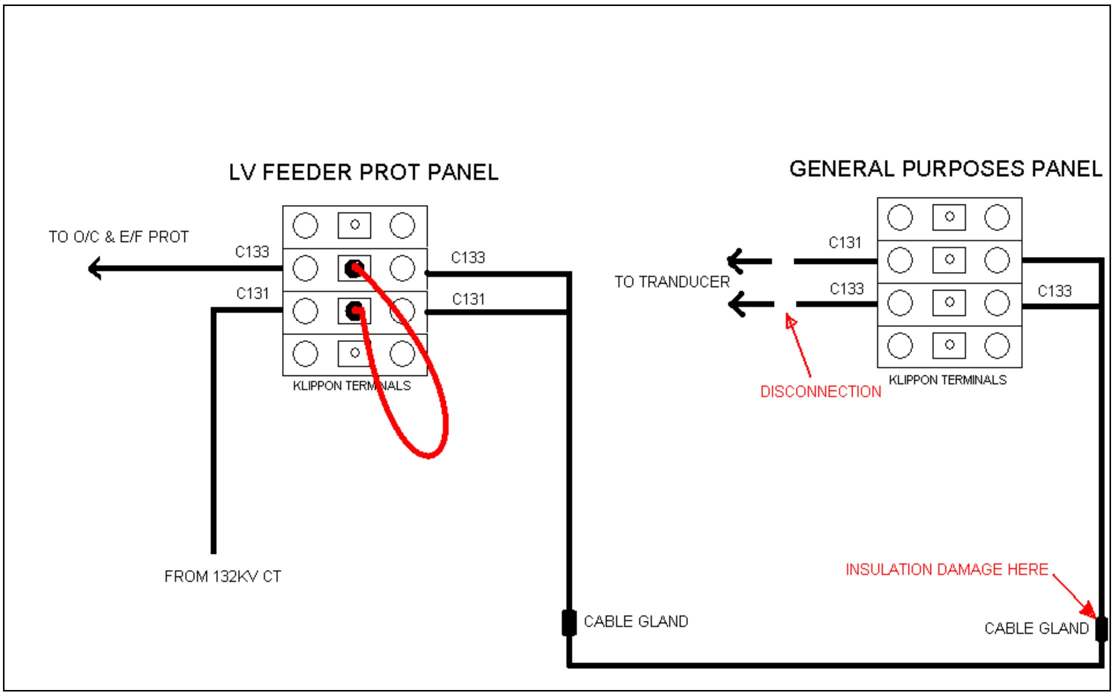


Figure 39 – Application of Remedial Short Circuit

With reference to Figure 39, its was decided to fit test plugs to Klippon terminals C131 & C133 in the LV Feeder Protection Panel, and apply a temporary short to rectify the fault after referring to relevant drawings.

Figure 40 – Safe Application of Short Circuit

With reference to Figure 40, 1000V+ insulated tools were used whilst applying the short circuit, as a precautionary personal safety measure.

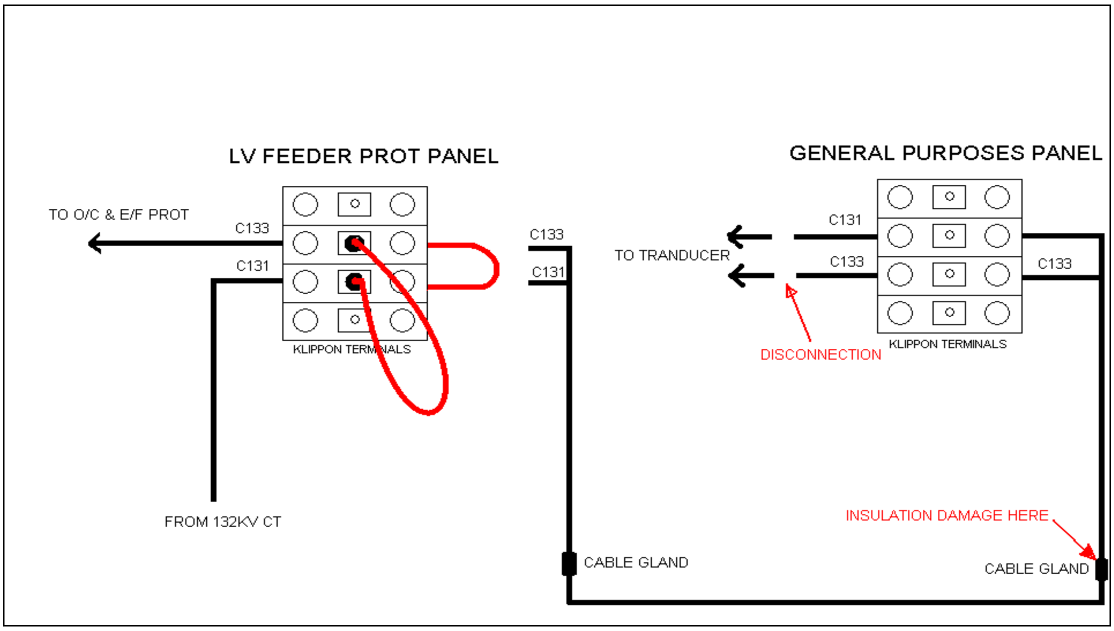


Figure 41 – Disconnection of Faulty Cable

With reference to Figure 41, the faulty cable was removed and a permanent short was applied across the CT open circuit.

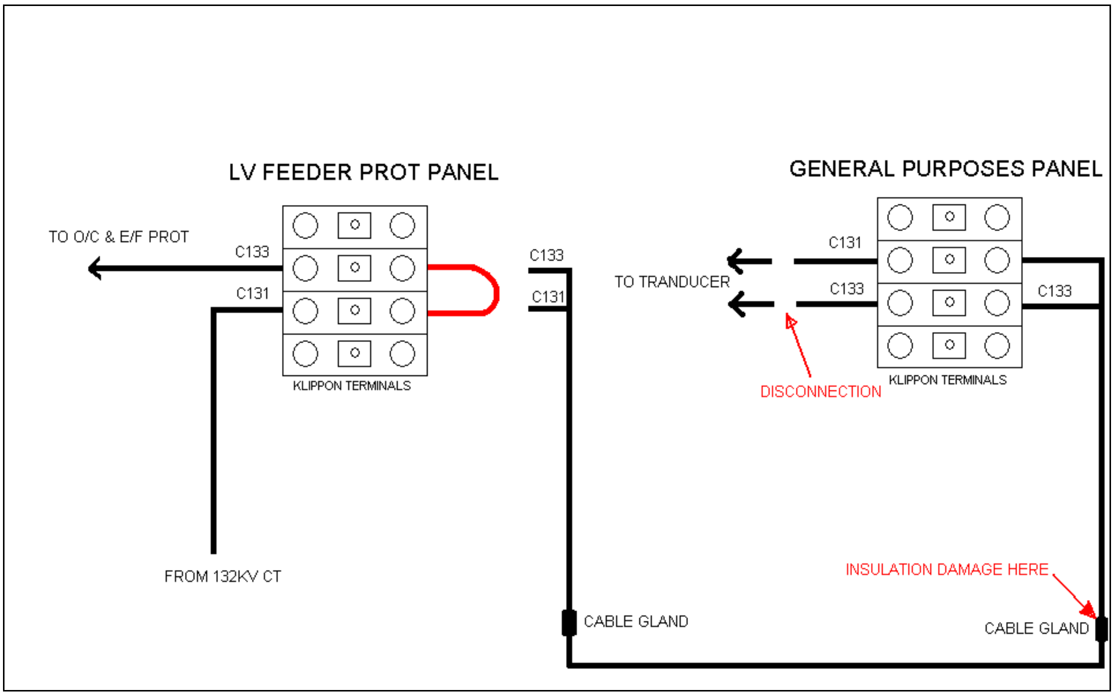


Figure 42 - As left on the day

With reference to Figure 42, the temporary short was then removed.

7.11 Summary of the incorrect SGT8 ILOC protection application

1. Despite NGC's reasonably clear specification, especially in terms of the protection schematic diagram that accompanied the tender document, it appears that the Contractor had been confused as to the actual requirements for SGT 132 kV protection at the Hams Hall/Lea Marston substation.

2. The NGC specification required only Interlocked Overcurrent protection at the 132 kV substation, but the contractor had engineered and supplied a scheme, based on a multi-function numerical relay, which provided both System Back-Up (non-interlocked) Overcurrent and Earth Fault protection and supplementary Interlocked Overcurrent protection.

3. The title of the Contractors' scheme drawing number T1/42/152119, which had been submitted to NGC, was "Circuit Diagram 3 Phase Overcurrent and Earth Fault Protection". There was no specific reference on the diagram to Interlocked Overcurrent protection. This should have been picked up by the NGC Commissioning Panel and by the approved NGC Settings Engineer as an issue that required some investigation/clarification against the Contractor's reviewed Design Intent Document, before commissioning commenced.

4. In a settings calculation sheet, the approved NGC Settings Engineer, who was a sub-contracted Consultant, had calculated appropriate generic settings for the ILOC functionality of the Contractor's protection scheme, but the settings were not clearly linked to the particular parameters of the KCGG142 protection relay.

5. In the production of the definitive MARS setting sheet for the KCGG142 relay, it is clear that there was a failure by the approved NGC Settings Engineer to prescribe settings that would prevent the unwanted non-interlocked overcurrent and earth fault protection functionality of the Contractor's scheme from interfering with system operation and normal system fault clearance.

6. On the definitive NGC MARS summary sheet, the non-interlocked overcurrent <u>and</u> earth fault protection elements of the relay had actually been assigned to operate trip output and alarm relay contacts, so the unwanted protection was effectively enabled. The setting parameters for the non-interlocked protection functions had been annotated as "not used", but such settings do not exist. As a result, the non-interlocked overcurrent protection was left at its factory default current setting, which was equivalent to 1000 Amps primary. The prescribed time setting had been changed from the default definite time setting of 60 seconds to zero seconds. The non-interlocked earth fault protection settings parameters were not even listed on the MARS sheet, so it is assumed that they were left at the default settings equivalent to 200 Amps primary, with a definite time delay of 100 seconds.

7. NGC has confirmed that the complete ILOC protection scheme information had been provided to the approved NGC Settings Engineer. Furthermore, NGC stated that discussions had taken place between the scheme supplier and the Settings Engineer to facilitate understanding of the relay logic proposed by the supplier. It is not clear,

therefore, why the MARS sheet errors and omissions were made or why the Settings Engineer did not highlight the fact that the proposed scheme was not entirely appropriate.

8. When considering timescales for settings and commissioning activities, there is some indication that the provision of relay settings had, for reasons unknown, become the critical path for SGT8 commissioning.

9. It might be argued that the Contractor's Commissioning Engineer should have queried the use of the "not used" terms on the MARS sheet when applying settings to the relay, rather than leaving the particular settings at their default values, but a Commissioning Engineer could understandably have assumed that the terms indicated that the settings for the particular parameters were the equivalent of "not relevant", with the assumption that the Settings Engineer had rendered the associated element ineffective through other settings.

10. As a result of the settings actually applied to the protection relay, any external fault fed by the transformer, or any heavy load current above 1000 Amps at 132 kV (229 MVA), would result in instantaneous protection tripping of the SGT8 400 kV and 132 kV Circuit Breakers.

11. The first incorrect SGT8 load trip came on 5 September, which was 16 days after SGT8 had first been loaded. From NGC loading records for SGT8, it appears that it had also been extremely close to tripping incorrectly at around noon on 28 August.

12. The commissioning test procedure applied by the Contractor was clearly inadequate for the proper testing of the ILOC protection scheme. It would only have sufficed as a partial function test record. Although the protection relay in question was Type Registered with NGC, there was no formally approved Site Commissioning Test (SCT) document template for the ILOC scheme. NGC subsequently stated its view that the use of the manufacturer's own commissioning test sheet, being derived from the service manual of the Type Registered relay, was adequate to check the general functionality of the relay type. However, NGC recognised that the sheet does fall short for testing particular applications of the relay, such as an Interlocked Overcurrent protection function. The sheet had not been formally registered by NGC as an SCT document for the relay type.

13. Under TP106 requirements, the Contractor's test procedure was to cover Stage-1 testing. The complete test record was signed by the Contractor's Commissioning Engineer only. Under TP106, at the discretion of the Commissioning Panel, it may not be necessary for Stage-1 tests to be witnessed. Such agreements would be documented in the Commissioning Programme, but this key document, which is required under TP106, does not appear to exist, since no copy has been provided.

14. Even if adequate ILOC test procedures had been applied, it is unlikely that the erroneous enabling of non-interlocked overcurrent protection within the multi-function KCGG142 relay and its undue restriction on SGT8 loadability would have been highlighted unless a loadability test had been applied to the protection scheme to

confirm that the transformer could be loaded up to its emergency rating without any protection element issuing an unwanted trip. Such testing is not yet widely applied by other TNO's worldwide, but the Consultants recommend some testing of this form for the future, when commissioning multi-function relays.

15. The Contractor had incorrectly engineered SGT intertripping arrangements from the 132 kV substation to the 400 kV substation, whereby operation of the 132 kV busbar protection would intertrip the 400 kV SGT Circuit Breaker. This unwanted arrangement actually negated the need for ILOC protection. Having subsequently identified what appeared to be an error, the Contractor brought it to NGC's attention on 29 August 2003, after SGT8 had been on load for 9 days.

16. The Contractor's identification of the apparent 132 kV Busbar Protection intertripping error for SGT8 may have followed internal discussion after feedback from the Contractor's Commissioning Engineer, regarding the ILOC protection. NGC advised the Consultants verbally that he was regarded as being capable and experienced and that he was fully authorised under NGC rules, but in discussions with NGC after the incident of 5 September, he had indicated that he had experienced some confusion about the commissioning of the ILOC protection relay for SGT8.

17. ✂

18. Examination of the Contractor's timesheets shows that three of the four commissioning engineers had worked, on average, between 50 to 60 hours per week over the five weeks prior to the Hams Hall incident. Given the nature of commissioning work, the Consultants do not regard this as excessive and, at certain stages in the commissioning programme, it may be necessary for engineers to work well in excess of the 48 hours per week average laid down in the EU directive. ✂ NGC has emphasised that the commissioning process is one of intense activity, interspersed with periods of waiting for the appropriate system conditions to allow work to proceed directly on the transmission system and they stated that their site staff are supported by a range of specialist engineers who spend significant time on site during the commissioning period. Whilst it is accepted from NGC's statement that they do take their responsibilities for a safe and healthy workplace seriously ✂.

7.12 Summary of the SGT6 open circuit current transformer incident

1. As part of the work to replace the old METERO SCADA system at the 400 kV substation, work was in progress to interface the new SCS system to instrumentation CT's and VT's and to remove wiring and equipment that had been identified on drawings as being redundant.

2. A Contractor's Wireman, opened a general services cubicle in the SGT6 400 kV relay room to commence SCS interfacing work, but he found that there was wiring and redundant equipment present that was not shown on the marked-up copy of the master drawing that he was working to. He flagged up the matter with his supervisor and the Contractor's Commissioning Engineer.

3. NGC's account is that the Contractors reviewed the situation on site with NGC staff. Their wireman was subsequently advised to remove some of the redundant wiring and equipment that was not shown on the drawing, to make room for the new SCS wiring. This was apparently on the understanding that the wiring to be removed was not associated with any CT circuits. Due to the complexity of the operation, the Contractor's Commissioning Engineer, who is regarded by NGC as being capable and experienced and who had been approved by the project Commissioning Panel, carried out the removal of the redundant wiring himself. It was during his work that the wiring of a 132kV CT circuit was cut.

4. Whenever a Contractor undertakes work on an NGC site, the Contractor is responsible for marking up and creating new site master drawings according to changes that have been made. It is not uncommon, however, for some lag to exist between changed equipment status and site drawing status. In this case, it appeared that the Contractor for some previous work had created a drawing revision lead. It appears that they had been ahead of intended work on site to remove redundant wiring and equipment and some deletions were made to a drawing that had not actually occurred in practice.

5. As the Contractor's Commissioning Engineer disconnected the redundant wiring to allow new wiring to be connected, he cut the Yellow phase 132 kV CT circuit wiring to remove a current transducer from the cubicle. The Commissioning Engineer would have been very much aware of the necessity to link any break in an operational CT circuit. For some reason he was either not aware that a CT circuit had been cut or he forgot to arrange for the circuit to be remade via a link. It may be that his work had been interrupted by some other pressing issue. Since the wiring had been tidied without making a link, the break in the CT circuit could not easily have been seen when looking into the cubicle and this maybe the reason why the need for a link was overlooked.

6. After having performed any modification work on CT secondary circuits, tests should be conducted afterwards to prove the circuits. Tests may have been omitted in this case due to that fact that the work to remove equipment not shown on a drawing was unplanned work, or that there was no knowledge of a CT circuit having been interfered with.

7. ✂

8. After SGT6 was commissioned in the evening of 4 September, it was not until the load on the transformer increased to a substantial level, during the morning of 5 September, that the break in the CT circuit became noticed by NGC staff, through the burning of the wiring caused by sparking across the open CT circuit.

9. The authorised de-loading of SGT6, by locally opening its 132 kV Circuit Breaker, made it possible for a link to be safely made in the open CT circuit, such that the transformer could be quickly put back on load. In the intervening period, however, the de-loading of SGT6 and the increased loading of SGT8 caused the defective SGT8 132 kV protection scheme to operate incorrectly, which caused the blackout.

10. NGC has stated that, due to the circumstances at Hams Hall on 5 September 2003, the CT and associated wiring was not checked for possible damage before it was returned to service on 5 September 2003. However, SGT6 was apparently taken out of service a week later and the CT was subjected to magnetisation current and insulation resistance tests, with satisfactory results.

7.13 Conclusions regarding the Birmingham incident

The following conclusions are drawn with regard to the incorrect trip of SGT8 on 5 September 2003:

1. The Contractor did not appear to have understood that only Interlocked Overcurrent protection was required for the 132 kV protection of SGT8.

2. The Contractor had engineered and delivered a protection scheme, based on a multi-functional numerical relay, which provided unwanted, non-interlocked Overcurrent and Earth Fault protection, as well as the required ILOC protection, through its proposed configuration settings and scheme wiring.

3. The NGT Commissioning Panel and the NGT approved Settings Engineer failed to identify the Contractor's confusion before commissioning took place, concerning their commitment to provide the specified ILOC protection and the inappropriate protection scheme design that they had supplied.

4. The approved NGC Settings Engineer, who prepared settings for the ILOC functionality of the protection scheme and who completed the definitive NGC MARS setting sheet, failed to prescribe settings that would effectively prevent the unwanted, non-interlocked, overcurrent and earth fault protection functionality of the Contractor's scheme from interfering with system operation and normal system fault clearance.

5. The commissioning test procedure used by the Contractor for the SGT8 132 kV ILOC protection was inadequate and there was no NGC approved Site Commissioning Test (SCT) test procedure for the ILOC protection scheme that had been supplied.

6. A Commissioning Programme document, as required under Transmission Procedure TP106, does not appear to have been issued, since no copy has been provided for review, in response to requests.

7. There was apparently a collective commissioning management failing of both NGC and the Contractor, as members of the Commissioning Panel chaired by NGC, to ensure that the SGT8 ILOC protection scheme was commissioned according to NGC's established standard procedures, supported by the documentation required under NGC's Transmission Procedure TP106, for Equipment Commissioning and Decommissioning.

8. Even if appropriate ILOC test procedures had been applied, it is unlikely that the erroneous enabling of non-interlocked overcurrent protection by settings errors and its undue restriction on SGT8 loadability would have been highlighted. Only the blind application of a loadability test to the protection scheme would have confirmed that the transformer could be loaded up to its emergency rating without any protection element issuing an unwanted trip. Such testing is not yet widely applied by other TNO's worldwide, but some testing of this form is recommended by the Consultants for the future, when commissioning multi-function relays.

9. A high volume of complex work is being undertaken in operational substations at Hams Hall.

The open circuit CT for SGT6, which precipitated the incident of 5 September 2003, resulted from the following factors:

1. A master drawing issued by a Contractor from previous work was ahead of the actual status of equipment on site.

2. Items had been deleted from the master drawing that had not actually been removed on site.

3. An omission by the Contractor's and NGC staff to have the site drawing discrepancy properly researched before the Contractors were conditionally instructed to remove non-documented wiring and equipment.

4. ✂

8. REVIEW OF NGC PERFORMANCE AND INTERNAL RESOURCES

8.1 Review of NGC protection 10-year performance indices

In response to the Consultants' question PBP014, NGC provided a statistical summary of performance for all their transmission protection systems (Main and Back-up) for the last 10 years. Their summary, which includes the definitions of the protection dependability and security indices used, has been included in APPENDIX B.

With reference to APPENDIX B, the dependability of protection, for clearing faults when required to do so, is high. The dependability index covers all individual protection systems. Since NGC now have two redundant Main protection systems applied to plant and circuits and since Circuit Breaker Fail protection is provided in lieu of Circuit Breaker redundancy, the dependability of clearing faults by at least one Main protection system will be even higher. The question might be asked, therefore, as to why it is necessary for NGC to invest in the provision of remote "System Back-Up" protection anymore - especially since many of the world's wide-area power failures have been caused by the unwanted operation of remote Back-Up protection. The protection relays that operated incorrectly for the incidents under investigation were both Back-Up protection relays. Some comparable TNO's in other countries do not apply Back-Up protection as extensively as NGC. NGC's Back-Up protection policy will be discussed further in the next Section.

With reference to APPENDIX B, the security of protection, to remain stable during correct clearance of faults by other protection systems, has been variable over the last 10 years. NGC has attributed past security problems to a particular form of Feeder protection that had poor performance and to telecommunications problems. For some Feeder protection systems, signalling via a telecommunications link is necessary to prevent the protection from operating for faults located outside the protected Feeder. The Consultant's are aware that telecommunications links of low dependability did result in incorrect operations of such Feeder protection systems in the UK. However, in APPENDIX B, NGC draws attention to the fact that there has been a programme of early replacement of the poorly performing Feeder protection systems and that there has been an improvement in the main telecommunications links. NGC's "*analysis of the number of unwanted power system fault trips associated with communication problems shows a reduction in recent years*".

Despite the fact that NGC confirms that past security problems related to a particular type of Feeder protection and to poor telecommunications links have been gradually dealt with, the protection security index still decreased significantly in the year 2002/2003. NGC points to the fact that the 5-year moving average security index has gradually increased since 1998/1999. However, the increase in 2002/2003 is due to the poor figure for 1997/1998 falling outside the 5-year window and not due to improved security in 2002/2003. The Consultant's review of the Loss of Supply summaries in NGC's System Performance Reports of 2002/03 and 2001/02 (see Section 8.4) indicates that the drop in security in 2002/2003 was due to a number of incorrect protection operations due to settings errors.

8.2 Review of NGC back-up protection policy and performance

8.2.1 Back-up protection performance

In response to the Consultants' question PBP015, NGC provided a statistical summary for their reported transmission Back-Up protection system operations for the last 10 years, up to the Hams Hall incident of 5 September 2003. Their summary has been included in APPENDIX C and the details have been summarised in Table 2 below. NGC also provided an explanation of their Back-Up protection application philosophy, which precedes their Table in APPENDIX C.

With reference to APPENDIX C, and to subsequent correspondence discussions with NGC, via Ofgem, NGC has attributed 5 incorrect Back-Up protection trips, out of a total of 38 operations, to incorrect relay settings having been applied. Thus, the human error element, as with the incorrect relay operations at Wimbledon and Hams Hall is at the forefront of insecure Back-up protection. NGC also stated that only 9 of the 38 incorrect protection operations resulted in any loss of supply.

Table 2 – Summary of NGC Reported back-Up Protection Operations for Last 10 Years

Protection Function	Correct	Incorrect	Total
Circuit Breaker Fail	12	0	12
Feeder Distance	1	0	1
Earth Fault	6	1	7
Interlocked Overcurrent	1	0	1
Overcurrent	9	5	14
Thermal Overload	2	0	2
Relay Failure	0	1	1
Grand Total	31	7	38

With reference to Table 2, 31.5% of all Back-Up protection operations have been correct operations of CB Fail protection. Reference to APPENDIX C confirms that these operations have been fairly evenly distributed over the last 10 years. This information certainly justifies the past and continued investment in CB Fail protection, which ensures that a fault will cleared as rapidly as possible, once it is clear that a circuit breaker has failed to respond to a Main protection trip command to clear a fault. Without CB Fail protection, it would be left to time delayed remote back-up protection functions to clear a fault, but the delay in clearance could jeopardise the transient stability of the entire transmission network and generation, where the result could be a total system collapse. As already mentioned in the preceding Section, the provision of CB Fail protection, in addition to redundant Main protection systems, is one of the possible arguments against the deployment of remote "System Back-Up" protection

Regarding the number of distance protection Back-Up zone operations, the Consultants were surprised that the number was so low - having been aware of NGC having had some Zone-3 back-up protection operations in the past and that some of those had been incorrect.

However, a verbal check with an ex-NGC engineer confirmed that those incidents would have been outside the 10-year review window.

Regarding Back-Up earth fault protection, there have been 6 correct operations over the last 10 years. However, some earth fault protection functions deployed by NGC are not actually solely for Back-Up protection. Time delayed, residual current earth fault relays applied to overhead line Feeders are actually Main protection for detection of any high resistance earth fault that might not be detected by either of the Main protection systems applied to the Feeder. Whilst such faults are quite rare in the UK and whilst fast protection operation is not essential, as long as protection discrimination is assured, such faults have actually occurred (e.g. a fallen 275 kV conductor touching a dry stone wall). Whilst more elaborate and faster high resistance earth fault protection systems are deployed in other countries, where high resistance overhead line faults are frequently experienced, due to smoke from bushfires or rapidly growing vegetation etc., the application of dependent-time earth fault relays to overhead line circuits is satisfactory in the UK, as supplementary Main protection. On an interconnected system, where single pole tripping is not applied, such protection can be inherently discriminative for clearance of a high resistance feeder fault and it can also provide remote Back-Up earth fault protection. For cable Feeders or for transformers, where high resistance faults are not an issue, any residual current or neutral connection earth fault protection applied will be purely for remote back-up protection.

The need for the deployment of 132 kV Interlocked Overcurrent protection, as per SGT8 at Hams Hall, is highlighted by the fact that there has been one correct operation of such protection over the last 10 years. With the possible increased deployment of 132 kV Gas Insulated Switchgear within cities in the future, with CT's located on one side of a transformer circuit breaker, the provision of such protection is justifiable. It is a relatively low cost function to provide, but it must be applied, set and commissioned correctly for security.

It is not surprising that 5 out of the 7 incorrect Back-Up protection operations that have been reported by NGC have been overcurrent relay operations. With the possible exception of Zone-3 back-up distance protection, non-interlocked overcurrent protection is susceptible to rapid incorrect operation under heavy load conditions if it is not set correctly. The relay trips at Wimbledon and Hams Hall are extreme examples of this fact, albeit that the incorrect effective setting of the Wimbledon protection was due to the installation of a relay of incorrect rating, rather than a settings calculation or application error, and the relay at Hams Hall had inappropriately set overcurrent elements enabled that shouldn't have been enabled.

Only two thermal overload protection operations have been declared for the last 10 years and the operations were apparently correct. Such protection is applied to guard against thermal damage to costly items of plant such as cables and transformers, which might arise due to operator error or due to failure of some forced cooling system. Even though such protection operations might be rare, its application can be cost-justified in consideration of the cost of losing and replacing a transformer or cable.

At their meeting with NGC at Wimbledon on 16 October, the Consultants' queried the scope of the protection operations listed in APPENDIX C, since a particular case of System Back-Up earth fault relay tripping of two Super Grid Transformers was known to the Consultants, which had not been listed. This was where both 275 kV/66 kV SGT's at Hawthorn Pit

Substation had tripped on 26 June 2001, during DNO Back-up protection clearance of a 66 kV line earth fault. Irrespective of whether the NGC protection operation had been correct or not, the Consultant's queried why the event had not been listed in NGC's response to question PBP015. NGC's response was that they had only listed protection operations for events that were reportable to Ofgem, under Licence Condition rules and since the event referred to had been triggered by a DNO fault, rather than by an NGC fault, it was not reportable. This explanation concurs with the fact that the incident is not listed in the losses of supply listing in NGC's 2001/2002 System Performance Report to Ofgem (see extract in page 3 of APPENDIX E), but it means that the statistics summarised in Table 2 are for reported operations rather than for all operations.

8.2.2 Back-up protection policy

A full review of NGC's Back-Up protection policies is beyond the scope of this investigation report, but the following comments are made in relation to the itemised justifications provided by NGC as part of their response to Consultant's question PBP015.

a) **Circuit Breaker Fail Protection** – This is quite clearly justified from NGC's performance statistics for the last 10 years, which have already been discussed in the preceding sub-section; so as to minimise any threat to system transient stability. In fact the provision of CB Fail protection, in lieu of unjustifiable CB redundancy, may obviate the need for some remote Back-Up protection.

b) **Feeder Back-up Protection**

- NGC's stated purpose for distance relay Zone-2 protection, as remote back-up for clearance of a busbar fault at the remote end substation is justifiable and especially with regard to Gas Insulated Switchgear (GIS), where its rather limited internal arcing fault withstand time might even warrant a reduction of the Zone-2 time delay to less than the NGC's prescribed 0.5 seconds delay (TPS 2.24.3). In some cases, the GIS might be fitted with pressure switches that could provide fast and effective Main-2 busbar protection, which would then obviate or lessen the need for Zone-2 remote Back-Up.

- For the less common case of Feeder's with both main protection systems being unit protection, such as the Wimbledon – New Cross 2 Feeder and where there is no remote back-up capability as part of the Main protection relays, NGC's requirement is for the application of Overcurrent protection (under NGTS 3.24.7). NGC's comment in APPENDIX C is that this protection would then act as remote Back-Up protection for a busbar fault. This is somewhat justifiable, but the response time would be too slow in many cases. Modern unit protection systems are now available with integral Back-Up "Zone-2" distance protection that would be better suited for this purpose since the Back-Up distance protection could also cope with seasonal/daily variations in system fault level and the reach of its coverage can be accurately controlled.

- In their response in APPENDIX C, it is noted that NGC has made no comment about Zone-3 protection application. For Feeders with distance protection relays, NGC applies Zone-3 protection as part of an historical practice to provide remote Back-Up protection for clearance of adjacent Feeder faults, which NGC also alluded to in its comment (e) in APPENDIX C. However, this protection must be set so as not see through transformers to any 132 kV fault (TPS 2.24.3). Although the setting guidelines in TPS 2.24.3 have now been simplified, with less emphasis on the remote back-up role of Zone-3, the practice of applying this protection is still questionable where two fully redundant Main protection systems are applied to all plant and circuits, where duplicated substation batteries are provided and where CB Fail protection is provided. Some TNO's in other countries do not apply Zone-3 protection.

- In their response in APPENDIX C, it is noted that NGC has made no comment about the application of Overcurrent protection to cable Feeders, such as the Wimbledon to New Cross 2 circuit. With an EHV transmission Cable circuit being an extremely costly asset, which could be damaged by the passage of heavy current for an excessive period to a fault located either within or outside the cable, Overcurrent protection should be applied, irrespective of whether or not one of the Main protection systems is non-unit protection. Dependent-time Overcurrent protection should be set with a operating characteristic and a margin to shadow the cable short-time fault current withstand characteristic.

- To prevent long-term damage to a cable circuit, where it might be possible to overload a cable for a prolonged period, some form of Thermal Overload protection is justifiable, which might be based on a current-operated thermal replica relay or on direct measurement of cable temperature (e.g. via optical fibre technology).

c) **Feeder Back-Up Earth Fault Protection** – NGC's justification for this protection is for the detection of a high resistance earth fault that might not be detected by either of the Main protection systems in certain cases. This would be a justifiable concern for an overhead line or a hybrid line/cable circuit but it should not be an issue for a completely cabled circuit. As already discussed in Section 8.2.1, the Consultants would regard protection for this purpose as Main protection for a high resistance earth fault and not Back-Up protection, even though the protection would be time delayed in operation in the UK, where high resistance faults are relatively rare.

d) **Transformer Protection** – As for a cable, a transformer is a costly plant item and System Back-Up protection is justifiable to prevent the possibility of through fault damage being inflicted by exceeding the transformer short-time current withstand. System Back-Up LV Earth Fault Protection is also justifiable at 132 kV to back-up the protection provided by a DNO, which is outside NGC's direct control.

8.2.3 Back-up protection history

To examine the historical perspective, the Consultants briefly reviewed a copy of CEGB Technical Development Report of 1988 that was entitled "Supergrid System Back-Up Protection". The report had reviewed the actions of transmission system Back-Up protection over an 18 year period between 1969 and 1987. There had been 14 occasions where time delayed Back-Up protection had been called upon to clear transmission system faults, due to failure of high-speed Main protection systems to clear the faults. There had also been 46 cases where transmission system Back-Up protection was called upon to clear DNO (Area Board) faults, due failures of DNO Main and back-Up protection to clear the faults.

In citing the necessity for Back-Up protection, the 1988 report acknowledged that piecemeal protection refurbishment at the time meant that many transmission protection arrangements were still according to obsolescent standards, such that Main protection system redundancy was not universal. For example, there were cases where circuit Breakers had only a single trip coil, where there was a lack of teleprotection/intertripping signalling diversity, where there were single tripping systems and where there was a lack of CB Fail protection.

A scanned copy of the analysis summary table for the 14 faults considered in the CEGB 1988 report is provided in APPENDIX D. From study of the table, it is concluded that virtually all the incidents would have been addressed by adherence to NGC's modern standards - particularly for redundant main protection and signalling/communication paths, duplicate CB tripping systems and DC supplies, supplementary residual current earth fault protection for detection and clearance of high resistance earth faults, CB Fail protection, 132 kV Interlocked Overcurrent protection and System back-Up protection for DNO interface circuits. Even the system fault reference "MR164" had been cleared by distance Zone-2 protection.

In correspondence discussion with NGC, via Ofgem, NGC reported that the application of Back-Up protection was further reviewed in 1998 and again in 2002. On both occasions they did not identify any policy changes as being necessary, although the Consultants noted that NGC rules for setting distance Zone-3 back-up protection were changed in 2002.

Although it is beyond the scope of this report, it may be opportune for NGC to further consider its Back-Up protection policy with particular regard to the necessity for applying overcurrent protection to non-cable Feeders and Zone-3 distance protection.

8.3 Review of past NGC protection incident reports for losses of supply

In response to the Consultants' question PBP028, for details of major protection incidents over the last 10 years that resulted in losses of supply, NGC submitted 8 reports covering incidents going back to 1997. The reports have been reviewed and a summary of findings is offered in Table 3. It should be noted, in each case, that references to "Human Error" in

Table 3 are not specifically attributable to NGC or its contractors or even to any single individual. The term is used to describe the nature of incident. It is not the purpose of the Consultants to trawl through historical reports to try to identify which organisation or individual may have been primarily responsible for an error. It is typically the case that a series of errors by a series of individuals is the cause of any incident.

Table 3 – Review Summary for Loss of Supply Protection Incident Reports

Incident Date	Location	Description	Protection Involved	Reason(s)
03/09/97	Washway 275kV	Loss of temporary Penwortham – Washway – Kirkby + Kirkby – Rainhill No. 2 circuit during intertripping channel tests with Penwortham – Washway – Kirkby No. 1 circuit outage. Result was 14 sec. loss of 150MW load at Washway.	Incorrect Intertripping	▪ Equipment ▪ Human error - testing ▪ Parallel circuit outage
01/10/97	Axminster 400kV	Loss of Mannington – Chickerell – Axminster circuit during SVC re-commissioning tests at Mannington, with Exeter – Axminster circuit outage. Result was loss of 118MW load at Axminster for 30 mins.	Incorrect CB Fail	▪ Human error - testing ▪ Parallel circuit outage
27/02/98	Frodsham 400kV	Loss of 400kV supply to Manweb with loss of 86MW load to ICI for 14 minutes	Incorrect Busbar Protection	▪ Human error - testing
03/08/00	Northfleet W. 400kV	Loss of 2nd Kingsnorth/Barking 400/275kV infeed to Northfleet due to failure of 1st circuit 275kV CB to open during lightning fault on 1st 400kV circuit. Result was loss of 180MW at Northfleet for 40 mins	Correct 275kV System Back-up	▪ Human error – testing ▪ 275kV CB trip links had been removed and left out
26/03/02	Hawthorn Pit 275kV	Loss of 275/66kV SGT2, while SGT1 was on outage, due to incorrect manual operation of SGT 2 trip relay instead of SGT1 trip relay during testing. Result was	Incorrect trip relay operation	▪ Human error – testing ▪ Parallel circuit outage

Incident Date	Location	Description	Protection Involved	Reason(s)
		loss of 83MW for 10 mins.		
17/04/02	Rocksavage 400/132kV	Loss of supply from Rocksavage 400/132kV SGT1 to “Ineos”, while Frodsham 400/132kV SGT6 to “Ineos” was on outage, due to an incorrect SGT1 LV Back-Up O/C protection trip. Result was loss of 240MW for 70 mins to a major industrial user.	Incorrect Back-Up Overcurrent trip	▪ Human error – application of settings ▪ Parallel circuit outage ▪ No MARS sheet record
02/06/02	Tynemouth 275/11kV	Loss of 275/11kV SGT2B fed from Blyth - Tynemouth, while SGT4 was on outage, due to incorrect Main-2 distance relay tripping at Tynemouth, in response to lightning fault on Blyth – Harker 275kV line. Result was loss of 6MW for 32 mins. The 275kV line was quickly autoreclosed, but delay in 11kV restoration was due to failure of 11kV autoreclose and failure of NGC METRO monitoring to highlight loss of supply due to battery problems.	Incorrect Numerical Distance Relay trip and failure of 11kV autoreclose and failure of 48V Metro Battery	▪ Human error – determination of settings ▪ Parallel circuit outage ▪ Lack of Type Reg. Docs for distance relay ▪ Lack of battery equipment maintenance
01/01/03	Fourstones 20.5kV	Loss of new 275/20kV SGT1 feed from Harker - Blyth, while 20kV bus section to SGT2 was open, due to incorrect multi-function transformer protection operation with rising load. Result was loss of 3MW for 3 mins, until bus section was closed.	Multi-Function Transformer Protection Relay	▪ Human error – restoration of settings after testing ▪ Parallel supply not in service ▪ Multi-function relay complexity ▪ MARS sheet limitations

26/04/03	Fourstones 20.5kV	Loss of both 275/20kV SGT1 & 2 infeeds due to incorrect operation of both SGT Back-Up Earth Fault protection functions within multi-function System Back-Up protection relays in response to DNO 20kV system earth fault . Result was loss of ?MW for 11 mins, until LV CB's were reclosed.	Multi-System Backup Protection Relay	▪ Human error – application of settings ▪ Multi-function relay complexity ▪ MARS sheet limitations

With reference to the right hand column of Table 3, the most striking reasons for the losses of supply are listed in order of significance as follows:

1. Human error – testing, application of relay settings, determination of relay settings.
2. Simultaneous planned system outages – parallel circuit outage
3. Complexity of multi-function numerical relays
4. Inadequacy of the NGC MARS sheet format in relation to the range of settings for numerical relays

In the international experience of the Consultants, the human error factors and numerical relay setting complexity factors are being cited by other TNO's in developed countries as being the most significant reasons for losses of supply related to protection problems. ✂

8.4 Review of NGC system performance report supply losses

With reference to the marked-up Loss of Supply Summary extracts from NGC's 2002/2003 and 2001/2002 System Performance Report to Ofgem, given in APPENDIX E, it can be seen that three out of the 12 reported losses of supply incidents in 2002/2003 were related to protection and that all of them were related to incorrect relay settings. The extract was marked up after review of the incident reports summarised in Table 3. It was deduced that the reduction in the protection security index for the year 2002/2003 referred to in Section 8.1 was due to the effects of protection settings errors.

In passing, while reviewing the loss of supply incident summaries, the Consultants were puzzled by the fact that in both years there were reported trips of SGT1B due to "Buchholz Gas" Alarms. Since a BG Alarm would not result in an automatic trip, it is presumed that the trips must have been manually initiated by the System operators.

8.5 Review of NGC internal resources

8.5.1 Consultants' questions

With reference to Section 8.3, a major factor associated with NGC's reported loss of supply protection incidents over the last 5 years has been human error. Human error was also a major factor in relation to the wrong installation and wrong setting of the protection relays that tripped incorrectly at Wimbledon and Hams Hall, respectively. The question inevitably arises as to the quantity and quality of the human resources at NGC's disposal for protection asset management and especially for interfacing with contractors, in view of its extensive devolution of activities to Contractors and the significant protection asset replacement work that NGC has in progress.

To probe this area, the Consultants posed the following written questions. NGC's written responses are included in APPENDIX F.

- **PBP019** - State the numbers of engineers and technicians, currently employed directly by NGC, who interface with protection system Manufacturers/Contractors and who have specialist knowledge, training and at least 5 years experience in at least one of the following areas (provide brief job descriptions):
    - Protection system design, specification and application
    - Protection setting calculations and the management of settings records
    - Protection testing & commissioning and its supervision
    - Investigation of protection operations and incidents
- **PBP020** - With reference to item PBP019, summarise how the numbers and mix of directly employed staff have varied over the last 5 years.
- **PBP021** - State the plans that NGC has in place to ensure that it will have available the numbers of in-house staff, with sufficient knowledge and experience of protection systems, that it will require to meet its obligations for the future

8.5.2 Review of NGC responses

Through their knowledge of the protection engineering scene within the UK and internationally, the Consultants have noted that a number of TNO's, such as NGC, have been losing experienced protection engineers through voluntary redundancy or voluntary severance etc. and retirement. ✂ However, the staffing figures quoted by NGC, in response to Consultants' question PBP020, show that there has been no significant change in staffing numbers, except for the reduction in the Project Engineering and Installation-Phase staffing, where NGC points to its changed Contract Strategy and Manufacturers Support Agreements to account for this. The Consultants conclude, therefore, especially in the areas of Policy and Standards, that some of the experienced staff that voluntarily departed or retired from NGC's employment have been replaced by more junior staff. Such an approach is sustainable as long as adequate expertise can be retained.

The type of staff changes that have occurred within NGC and within other TNO's have been the subject of much debate internationally ✂. There is no reason, however, why NGC cannot choose to outsource many of the services it needs as long as the suppliers of equipment and services can deliver and as long as NGC retains sufficient numbers and quality of in-house staff to manage and supervise the outsourced resources.

Through the Consultants' review of NGC's standard procedures etc. in Section 4, increased outsourcing should not be problem as long as NGC's procedures are fully applied and as long as the outsourcing suppliers can acquire/retain staff in sufficient numbers and with sufficient experience/expertise to meet NGC's needs, but here lies a problem. It appears to be the case that all organisations involved with the Electricity Supply Industry within the UK and overseas (system operators, manufacturers, contractors and consultants) are finding that the resource pool of suitably qualified, experienced and motivated engineers is rapidly drying up. It was with this reality in mind that the Consultants posed question PB021, with regard to NGC's future needs.

During a discussion at the meeting between NGC and the Consultants at Wimbledon on 16 October 2003, NGC confirmed that recruitment and retention of engineering graduates is a real problem. It was acknowledged that there are very few young engineering graduates available within the UK. The Consultants concurred that most of the few undergraduates studying electrical power engineering topics at UK educational establishments are overseas students. In the event that graduates might be recruited, NGC stated that they have difficulty retaining them, since the graduate career aspirations tend to be beyond what they perceive NGC can offer.

In subsequent correspondence discussion, via Ofgem, NGC reports that for power engineering, in particular, it has seen a reduction in the number of universities and academic institutions that have power engineering as a mainstream course. It has taken a number of initiatives to ensure that it is able to consistently recruit the number of graduates that are needed to support its programmes across its business. To date, NGC states that it has been successful, but this has required a whole series of initiatives and the formation of strong relationships with universities. NGC states that it is an issue that needs to be closely monitored because power engineering has become less fashionable than perhaps it was a few years ago.

Regarding NGC's formal training arrangements for their own staff and for Contractors' staff, the Consultants queried whether there were any plans to close the NGC training establishment at Eakring, in general discussion with NGC at the meeting held at Wimbledon on 16 October. Although it was not minuted, NGC affirmed to the Consultants that this was not the case and that the amalgamation of its gas and electricity activities under NGT had strengthened the demand for maintaining its own training establishment.

9. A MAJOR LESSON TO BE LEARNED FROM BOTH INCIDENTS

Proving the loadability of a transmission Feeder or Transformer is vital for transmission system security, since it is following a forced outage of another Feeder or Transformer, where the system may already be under planned outage conditions, that the highest level of load current is likely to be experienced by a circuit. If the circuit protection then operates incorrectly, there may well be a major loss of load. It is the wrong time to discover that the protection is imposing some unforeseen loadability limit.

Whilst NGC's established procedures would probably have resulted in the incorrect relay rating being identified during commissioning tests at Wimbledon, if they had been fully applied, NGC has since recognised, in its remedial actions report of 15 October 2003, a need to introduce some form additional primary operating current check procedure to make their existing procedures more robust and the Consultants support this view.

For multi-function numerical protection relays, which are now being widely deployed as part of NGC's protection asset replacement programme and with many of NGC's previous in-house activities being devolved to Contractors, there is an additional need for dedicated circuit/plant loadability tests. Even if NGC's established procedures had been fully applied during commissioning of the SGT8 ILOC protection at Hams Hall, which was based on a multi-function relay, and even if a formal back-calculation procedure for primary operating current had been applied, the particular protection defect, caused by configuration settings errors, would probably not have been identified during commissioning.

Irrespective of any existing NGC Site Commissioning Test procedures, which may or may not be available for the particular types of protection that can be applied to a transmission circuit, the Consultants recommend that supplementary circuit loadability tests should be devised and conducted once all the service settings have been applied to the circuit protection systems. Such tests should prove that non of the protection systems will restrict the loadability of the circuit, up to the level of current expected by system planners and operators under emergency conditions. To allow for the responses of any voltage-dependent protection functions, as well as current-dependent functions, it is suggested that loadability tests should include the simulated application of a prescribed level of system voltage (e.g. 90%) and the simulated application of forward and reverse load flow at a prescribed load angle (e.g. 30^0 lagging).

10. REVIEW OF NGC PROPOSED REMEDIAL ACTIONS

In response to Consultants' questions PBP022/023, NGC provided a copy of its report of 15 October 2003 entitled "Review of Protection Remedial Actions arising from the South London and West Midlands Loss of Supply Incidents". A copy of the report is included as APPENDIX G. This has only been partly reviewed by the Consultants, but the following initial comments are made.

In Section 63 of the report, NGC has recognised the need for some additional procedure for checking the primary operating current of protection. Their suggestion is focussed on the back-calculation of primary operating current from the secondary pick-up current test results for a particular intended protection function. Such a procedure would certainly have been useful if it had been applied at Wimbledon, but it would still have failed to identify problems that might be caused by a non-intended protection function being active. For example, testing the pick-up current for the Interlocked Overcurrent measuring elements of the KCGG142 relay at Hams Hall and back calculating their primary operating current would have failed to identify that other non-interlocked protection functions, with higher current settings, had unintentionally been left enabled and that they would restrict the required loadability of a transformer.

Based on the review of some other blackout incidents outside the UK, it is the Consultants' view is that the only sure way to prove the loadability limits of a transmission circuit is to simulate the effects of emergency circuit loading for all its protection schemes. This must be both in terms of current and voltage, so that both overcurrent and under impedance back-up protection functions will be tested.

Since NGC issued its remedial actions report of 15 October, there has been some correspondence discussion with NGC, via Ofgem, regarding the issue of loadability testing. As reported in Section 4.8 of this report Volume 2.

In Section 45 of the NGC report, it is mentioned that a survey of 41,264 relays on the NGC transmission system had been completed within just over 1-month after the second blackout incident. It is understood that the figure quoted probably represents all of NGC's System Back-Up Overcurrent and earth Fault protection schemes, which will vary between the simple electromechanical relay units, to electronic relay units and to multi-function numerical relay units, as per the commentary in Section 3.2 of this report. ✂

11. OVERALL CONCLUSIONS

The main conclusions regarding the London and Birmingham blackout incidents have already been offered in Sections 6.9 and 7.13 and also in Sections 4.8 and 9, regarding the proving of transmission circuit loadability. The conclusions listed here are still focussed on transmission protection systems, but they are of a more generic nature, according to the terms of reference for the work of the Consultants.

1. Human error, related to the delivery of new protection systems, was responsible for both the London and Birmingham Blackout incidents

2. With one noted exception, related to new types of protection equipment, NGC has a sound set of defined practices and procedures laid down for the delivery of protection schemes for use on its transmission network, which cover their design, design approval, procurement, manufacture, setting and installation/integration.

3. The exception, in the opinion of the Consultants, is where numerical multi-function numerical relays are deployed, such as the type involved in the Birmingham incident, where there is the lack of a formalised procedure for verifying that such protection schemes will not interfere with the required loadability of transmission circuits and plant, through the inadvertent enabling of unwanted protection functions. Whilst NGC's existing procedures are in line with typical international practice, they tend to dwell on proving that the protection will behave as intended by the scheme Design Engineers and the Settings Engineers. It is the Consultants' experience, that there is growing international recognition that more general procedures will be required to determine that protection systems are fit for service, due to the increasing number of incidents related to multi-functional numerical protection relays and with the devolution of many activities by TNO's to Contractors. NGC needs to be absolutely sure that all plant and feeders can be loaded to their intended levels without premature protection intervention.

4. NGC has laid down suitable guidelines and procedures for the assessment and authorisation of its own staff and for Contractor's staff who might be involved with the delivery of protection schemes for use on its transmission network. This stemmed from the recognition by NGC, in a presentation to major suppliers on 6 December 2001, that the number of protection incidents arising from deficient commissioning practice had risen to an unacceptable level.

5. In common with other Transmission Network Operators world-wide, multi-function numerical relays are proving to be a new source of human error that NGC must address. Following the Consultants' review of the Birmingham incident and some other submitted NGC incident reports, the existing MARS setting summary sheets do not appear to be completely adequate, in format, for defining the protection function and configuration settings for such relays.

Ways should be found to improve the sheets to ensure that all the setting parameters that can influence relay behaviour, for a particular application, are listed.

6. From the evidence gathered and made available, it appears there were collective commissioning management failings of both NGC and the Contractors, as members of Commissioning Panels Chaired by NGC, to ensure that NGC's established practices and procedures were fully adhered to during the delivery of the new protection schemes for the New Cross 2 Feeder at Wimbledon in 2001 and for the SGT8 132 kV protection at Hams Hall in 2003. Both the Contractors and NGC appear to have made mistakes in the delivery of the schemes and the fact that NGC's practices and procedures do not appear to have been rigidly enforced appears to have contributed to certain errors passing unnoticed until they resulted in incorrect protection operations, during increased loading of circuits, following emergency switching operations, with the transmission networks under planned outage conditions.

7. ✂

8. Regarding NGC's protection incident investigation and reporting procedures and the Consultant's review of reports made available for incidents over the last 5 years, in comparison to NGC's public reports regarding the London and Birmingham incidents, the depth and detail of the public reports is not as great, which reflects the speed with which they were produced, to satisfy public concerns, and the lay audience to which they were addressed. Upon checking later, the Consultants were advised on 31 October that there were no further reports available for the London and Birmingham incidents, other than the protection remedial actions report of 15 October, which is referred to in Section 10. NGC offered assurance, however, that promised actions in their public reports were still being pursued and that the report of 15 October was being updated. ✂

9. From NGC's protection performance statistics for the last 10 years, which are attached as APPENDIX B and which are reviewed in Section 8.1, it was noted that there had been a significant decline in the protection security index in the financial year 2002/2003. The Consultants' review of NGC's submitted incident reports confirmed that all the incidents had been rooted in protection settings errors.

10. The Consultants' review of NGC's submitted protection incident reports related losses of supply for the last 10 years has highlighted that all the incidents were as the result of human error concerning the determination or application of protection settings or during protection testing. Most errors had occurred while the transmission system was already under planned outage conditions, due to maintenance / extension / refurbishment work.

11. After reviewing NGC's submitted summary of reported Back-up protection operations for the last 10 years, where only 9 out of the total of 38 operations resulted in losses of supply, the consultants noted that 7 of the incorrect operations had been for Overcurrent or earth-fault protection and 5 were due to incorrect protection settings.

12. The Consultants have commented on NGC's recently stated reasons for the application of Back-Up protection and on the reasons offered for its application in a 1988 CEGB report. NGC has reported that the application of such protection was reviewed in 1998 and again in 2002. On both occasions they did not identify any policy changes as being necessary, although the Consultants had noted that NGC rules for setting distance Zone-3 back-up protection were changed in 2002. The Consultants concur that the application of the particular protection functions that incorrectly operated at Wimbledon and Hams Hall was justified.

13. NGT now places great emphasis on outsourcing, through its new contract strategy and Service Agreements with suppliers. As with all organisations associated with the UK Electricity supply industry, NGC admits that it is becoming increasingly difficult to recruit and retain graduate engineers. NGC reports that for power engineering, in particular, it has seen a reduction in the number of universities and academic institutions that have power engineering as a mainstream course. It has taken a number of initiatives to ensure that it is able to consistently recruit the number of graduates that are needed to support its programmes across its business for the future. To date, NGC states that it has been successful, but this has required a whole series of initiatives and the formation of strong relationships with universities. NGC states that it is an issue that needs to be closely monitored because power engineering has become less fashionable than perhaps it was a few years ago. ✂

APPENDIX A

MC 3 & NEW CROSS 2 COMMISSIONING RECORD ANALYSIS FOR WIMBLEDON

Test Description	**Test Procedure Reference** **C = Cont.** **N = NGC**	**NGC Witness Required?**	**NGC Witness Signature?**	**Date Completed**	**Comm. Eng. ID**
New X 2 Main-1 Prot.	N Off-Load Tests SCT 20.19.2	✓	✓	24/05/01	CE - B
	N On-Load Tests SCT 20.19.2	✓	✗	Incomplete record and no record of completion	?
	N Trip/Aux Relay Tests SCT 20.3	✗	✓	01/06/01	CE - A
	N Insulation Tests SCT 20.4.1	✗	✓	01/06/01	CE - A
New X 2 Main-1 Intertrip	N Trip/Aux Relay Tests SCT 20.3	✗	✓	01/06/01	CE - A
	N Insulation Tests SCT 20.4.1	✗	✓	01/06/01	CE - A

Test Description	Test Procedure Reference C = Cont. N = NGC	NGC Witness Required?	NGC Witness Signature?	Date Completed	Comm. Eng. ID
New X 2 Main-2 Prot.	N Off-Load Tests SCT 20.17.2	✓	✗	25/05/01	CE - A
	N On-Load Tests SCT 20.17.2	✓	✗	25/05/01	CE - A
	N Trip/Aux Relay Tests SCT 20.3	✗	✗	01/06/01	CE - A
	N Insulation Tests SCT 20.4.1	✗	✗	01/06/01	CE - A
New X 2 Main-2 Intertrip	N Trip/Aux Relay Tests SCT 20.3	✗	✗	01/06/01	CE - A
	N Insulation Tests SCT 20.4.1	✗	✗	01/06/01	CE - A

Test Description	Test Procedure Reference C = Cont. N = NGC	NGC Witness Required?	NGC Witness Signature?	Date Completed	Comm. Eng. ID
New X 2 System Back-Up Protection	C MCGG22 Earth Fault Relay PTS264	✓	✘	01/06/01	CE - A
	C MCGG42 Overcurrent Relay PTS299	✓	✘	01/06/01	CE - A
	N Trip/Aux Relay Tests SCT 20.3	✘	✘	01/06/01	CE - A
	N Insulation Tests SCT 20.4.1	✘	✓	?	CE - A

Test Description	**Test Procedure Reference** **C = Cont.** **N = NGC**	**NGC Witness Required?**	**NGC Witness Signature?**	**Date Completed**	**Comm. Eng. ID**
Mesh Corner 3 Circulating Current Protection -1	N Trip/Aux Relay Tests SCT 20.3	✘	✘	01/06/01	CE - A
	C DAD STS1225	✘	✘	01/06/01	CE - A
Mesh Corner 3 Circulating Current Protection -2	N B3 SCT 20.7	✘	✘	01/06/01	CE - A
	N Insulation Tests SCT 20.4.1	✘	✘	01/06/01	CE - A
Mesh Corner 3 Feeder End Protection	N B3 SCT 20.7	?	✘	01/06/01	CE - A
	N Trip/Aux Relay Tests SCT 20.3	?	✘	01/06/01	CE - A

Test Description	Test Procedure Reference C = Cont. N = NGC	NGC Witness Required?	NGC Witness Signature?	Date Completed	Comm. Eng. ID
	N Insulation Tests SCT 20.4.1	?	✘	01/06/01	CE - A
Mesh Corner 3 CB Fail Protection	N Trip/Aux Relay Tests SCT 20.3	?	✓	01/06/01	CE - A
Circuit Breaker S30	C Trip Circuit Supervision PTS 110	✘	✓	01/06/01	CE - A
	N Trip/Aux Relay Tests SCT 20.3	✘	✓	01/06/01	CE - A
	N Insulation Tests SCT 20.4.1	✘	✘	01/06/01	CE - A
New X 2 Disconnector L30	N Inst. O/C + E/F relays SCT 20.5.2	✘	✓	10/04/01	CE - A

Test Description	Test Procedure Reference C = Cont. N = NGC	NGC Witness Required?	NGC Witness Signature?	Date Completed	Comm. Eng. ID
	N Insulation Tests SCT 20.4.1	✗	✓	01/06/01	CE - A

APPENDIX B

✂

APPENDIX C

NGC BACK-UP PROTECTION PERFORMANCE STATISTICS OVER THE LAST 10 YEARS

The transmission system is provided with two fast discriminative main protections, which will normally clear any type of primary fault with a clearance time adequate to both maintain power system stability and to prevent damage to equipment.

From time to time, however, an adverse combination of system parameters may result in a failure of the main protection to clear the fault. Back-up protection is then required to remove the fault from the system. Back-up protection cannot be guaranteed to preserve system stability nor prevent damage to equipment - but it will eventually disconnect the faulty equipment and greatly limits instability and equipment damage.

The requirement for back-up protection on the main interconnected transmission system and connected transformers are as follows:

(a) Circuit breaker fail (CB fail) is provided to clear faults from the system in the event of a circuit breaker failing to trip on receipt of a trip command.

(b) Feeder back-up protection (Distance Zone 2 and Overcurrent Protection) is provided to remove an uncleared busbar fault at the substation at the remote end of the feeder. This requirement follows from busbar protection operating on a two out of two equipment principle, which is therefore less dependable than the usual one out of two equipment principle applicable to the majority of the system.

(c) Feeder back-up protection (earth fault) to remove a high resistance feeder earth fault, which may not be detected by some main protections.

(d) Transformer back-up both to remove an uncleared transformer fault, and to remove an uncleared fault on the lower voltage system supplied by the transformer (Overcurrent, Earthfault, Interlocked Overcurrent and Thermal).

(e) Both (b) and (c) above also provide protection for uncleared faults which are at more remote points in the power system.

A summary list of the requested information is shown below.

List of back-up protection operations in the last 10 years

Fault Number	Fault Date	Correct/Incorrect Operation	Back-up Protection Type
F1993NE0754	27-Feb-94	Correct	CB Fail
F1994MA0386	05-Aug-94	Incorrect	Overcurrent
F1994NW0840	27-Mar-95	Correct	Earth Fault
F1995NE2114	26-Jan-96	Correct	Distance
F1995NW1322	29-Jan-96	Correct	Earth Fault
F1995NW1449	04-Feb-96	Correct	CB Fail
F1995NE2378	23-Feb-96	Correct	Thermal
F1996EA0172	14-Jun-96	Incorrect	Overcurrent
F1996MA0920	08-Oct-96	Correct	Earth Fault
F1996SW2214	18-Jan-97	Correct	Overcurrent
F1997NE0645	29-Aug-97	Correct	Earth Fault
F1997NW0625	17-Dec-97	Correct	CB Fail
F1997NW0661	25-Dec-97	Correct	Overcurrent
F1997NW0660	25-Dec-97	Correct	Overcurrent
F1997SW0396	03-Jan-98	Correct	CB Fail
F1998SE0073	21-Dec-98	Correct	CB Fail
F1999SW0037	02-Jun-99	Correct	CB Fail
F1999SW0046	28-Jun-99	Correct	Interlocked Overcurrent
F2000NE0009	27-May-00	Correct	CB Fail
F2000NE0017	30-Jun-00	Correct	Overcurrent
F2000SE0017	03-Aug-00	Correct	CB Fail
F2000NW0025	21-Aug-00	Correct	CB Fail
F2000NE0026	26-Sep-00	Correct	Earth Fault
F2000SE0033	07-Oct-00	Correct	CB Fail
F2000NW0035	30-Oct-00	Correct	Earth Fault
F2000SE0050	04-Nov-00	Correct	Overcurrent
F2000NE0098	18-Mar-01	Correct	Overcurrent
F2001NE0026	06-Jul-01	Correct	Overcurrent
F2001SE0064	10-Oct-01	Correct	CB Fail
F2001NE0062	14-Feb-02	Correct	Overcurrent
F2002NW0006	17-Apr-02	Incorrect	Overcurrent
F2002NW0037	20-Nov-02	Correct	CB Fail
F2002SE0061	10-Dec-02	Incorrect	Relay failure
F2002SW0044	05-Jan-03	Correct	Overcurrent
F2002NE0050	06-Mar-03	Correct	Thermal
42035	26-Apr-03	Incorrect	Earth Fault
49933	28-Aug-03	Incorrect	Overcurrent
50385	05-Sep-03	Incorrect	Overcurrent

APPENDIX D

EXTRACT - 1988 CEGB REPORT ON "SUPERGRID SYSTEM BACK-UP PROTECTION"

TABLE 1

SUMMARY OF SYSTEM FAULTS REQUIRING SYSTEM BACK-UP PROTECTION IN THE PERIOD 1969-1987

All Faults Requiring System Back-up (Note 6)	"High Resistance"	Would have been Improved By:-						
		Residual E/F Relay	Duplicate Intertrip	CB Fail Protection	Duplicate Trip Coils	Unit and Distance Protection	Duplicate Batteries	Modern Busbar/ HV Conns Protection
BM043	Yes	Yes	No	No	No	Note 3	No	No
SA085	No	Note 1	No	No	No	No	No	Yes
LS138	No	No	No	Note 2	No	No	No	No
GD191	Probably	Note 1	Note 1	No	No	Note 3	No	No
GD222	No	Note 1	No	Yes	Yes	No	No	No
BL095	Yes	Yes	Note 4	No	No	No	No	No
MR240	No	Note 1	No	Yes	Yes	No	No	No
BL221	Yes	Note 1	No	No	No	Note 3	No	No
MR164	No	No	No	No	No	No	No	No
MR303	No	No	No	Yes	Yes	No	No	No
SA054	No	No	No	No	No	Note 5	No	Yes
SA078	No	Note 1	Note 1	No	No	Note 5	No	Yes
GD116	No	No	No	Yes	No	No	No	No
SA139	No	Note 1	No	Note 1	No	No	No	No

Note 1 - Already fitted.
Note 2 - Yes but not fitted at 132 kV.
Note 3 - A unit protection might have helped depending on fault level.
Note 4 - Even one intertrip would have helped.
Note 5 - Yes on adjacent circuits.

Note 6 - BL Bristol
BM Birmingham
GD Grinstead
LS Leeds
MR Manchester
SA St Albans

APPENDIX E

LOSSES OF SUPPLY EXTRACT - NGC SYSTEM PERFORMANCE REPORTS

2002/03 & 2001/02

Losses of Supply due to faults on National Grid equipment (2002-03)

Incident Date, Time & Location	Incident Duration (Mins)	Max Demand Lost (MW)	Estimated Energy Unsupplied (MWh)	Comment
9 April, 07.45hrs at Amersham 132kV substation	18	80	24.00	The Iver-Amersham teed SGT2-East Claydon 400kV circuit was tripped by protection following a flashover within the (DNO) network when a circuit was isolated, in error. The Iver-Amersham teed SGT1-East Claydon 400kV circuit was on planned outage at the time. The tripped circuit was returned to service, when it was confirmed safe to do so, at 08.03hrs.
2 June, 22.32hrs at Tynemouth 275/11kV substation	89	6	8.9	The Blyth-Harker 275kV and Blyth-Tynemouth teed SGT2B circuits tripped during a lightning storm. As the Blyth-South Shields teed SGT4 circuit was on a planned outage at the time, supplies were lost to Tynemouth 11kV and the 11kV substation, known as Silverlink A, owned by a customer, ATMEL. Supplies were restored to the first Silverlink circuit following liaison with the customer at 00.01hrs. Incorrect protection settings/trip at Tynemouth
11 August, 15.25hrs at Lackenby 66kV substation	10 52 24	29 17 4	4.83 14.73 1.60	Lackenby 66kV substation is owned and controlled by Northern Electric Distribution Ltd (NEDL) and demand is normally supplied via three Supergrid transformers. As SGT1A was on planned outage, when SGT3 tripped due to a cable fault, an NEDL owned and controlled automatic load reduction scheme operated to reduce the load on the remaining transformer, SGT2A. Demand was restored in stages by liaison with the customer.
29 October, 02.48hrs at Imperial Park 400kV substation	1	11	0.18	The Imperial Park-Melksham circuit and Imperial Park SGT1 tripped and auto reclosed.The trip was caused by failure of a blue phase sub-conductor following earlier storm conditions. The Imperial Park-Cilfynydd was out of service for a planned outage at the time.
7 March, 16.41hrs at Margam 275/66kV substation	12	94	18.8	The Baglan Bay-Margam and the Margam-Pyle 275kV circuits tripped simultaneously following a lightning strike. Both circuits auto-reclosed successfully but the 66kV circuit breakers 1T0 & 2T0, maintained by WPD, failed to re-close. Supplies were restored progressively following the manual closure of 1T0.
Anomalous Losses				
17 April, 21.23hrs at Rock Savage 400/132kV substation	31	211	109.02	Rock Savage SGT1/Rock Savage power station/Frodsham 400kV circuit tripped resulting in a loss of supply to Power Systems (DNO) customer Ineos Chlor chemical works. The trip was caused by the operation of protection equipment reacting to erroneous settings. The alternative supply connection via SGT6 was on planned outage at the time.
3 May, 17.52hrs at Kemsley 132kV substation.	1	45	0.75	The Kemsley-Littlebrook-Beddington 400kV circuit tripped together with Kemsley SGT3A during a lightning storm. As SGT3A is the only supply to Sheerness Steel and Ridham Dock via a SEEBOARD owned 132kV circuit, supplies were lost.
29 July, 15.07hrs at Tinsley Park 275/33kV substation	6	57	5.70	The Brinsworth-Tinsley Park 1 275kV circuit tripped following a Buchholz Gas alarm on Supergrid Transformer SGT1B, causing a loss of supply to the Steel Works. The customer had chosen to take supplies from a single transformer only. Supplies were restored via SGT1A. Why should a BG Alarm cause a Trip?
4 August, 14.57hrs at Earlham/Sall 33kV substation.	20 10	60 36	20.00 6.00	The Norwich-Walpole 2 400kV circuit, Norwich SGT2 and the Norwich-Earlham/Sall 2 132/33kV circuit tripped during a lightning storm. Although Norwich SGT4 was on a planned outage, supplies would have been maintained via Norwich 132kV substation but the DNO had chosen to take a concurrent outage on their system resulting in the loss of supplies.
1 January, 03.53hrs at Fourstones 275/20.5kV substation	3	3	0.15	The Harker-Fourstones 400kV circuit and Fourstones SGT1 tripped. The trip was caused by the operation of transformer protection equipment reacting to erroneous settings.
5 January, 12.45hrs at Patford Bridge 400/25kV substation	1	10	0.16	The earthwire of the East Claydon-Enderby-Patford Bridge 400kV double circuit was severed when it was struck by a light aircraft. Both circuits had to be switched out of service to allow safe access to the site for emergency services. Supplies to Railtrack were restored via alternative routes and were lost for circuit switching time only.
5 February, 15.13hrs at Elstree 275/132kV	<1	9.2	0.15	When a scaffold pole fell against a 275kV Current Transformer, Main Busbar 2 tripped resulting in a loss of supplies to DNO, 24/7, due to customer chosen running arrangements. Supplies were restored after 53 seconds following operation of the 24/7 auto-close scheme.

Losses of Supply due to faults on National Grid equipment (2001 - 2002)

Incident Date, Time & Location	Incident Duration (Mins)	Max Demand Lost (MW)	Estimated Energy Unsupplied (MWh)	Comment
27 April, 14.37hrs at Wincobank 275kV substation	58	26	7.7	The Wincobank/SGT2-Templeborough/SGT3 275kV circuit tripped when the cable between the substations was struck and damaged by a third party's civil engineering contractor. Demand was restored in stages by switching on the Yorkshire Electricity LV network. At the time of the incident Wincobank demand was on single circuit supply risk due to planned outage of the Pitsmoor-Wincobank 275kV circuit.
10 May, 21.19hrs at Axminster 400kV substation	81	125	117.7	The Mannington-Chickerell-Axminster 400kV circuit tripped during a lightning storm but did not reclose automatically resulting in an initial loss of 125MW. Approximately half the demand was restored in stages within an hour via Western Power Distribution and Scottish & Southern's LV network. The remaining demand was restored when the National Grid circuit was returned to service by manual switching at 22.40hrs. Axminster demand was on single circuit risk at the time due to a planned outage of the Exeter-Axminster 400kV circuit.
15 June, 15.41hrs at Rassau 400kV substation	1.5	147	3.7	The Cilfynydd-Rassau and the Rassau-Walham 400kV circuits tripped at approximately the same time during a lightning storm. Supplies were restored when the Cilfynydd-Rassau circuit reclosed automatically in approximately 90 seconds. The Rassau-Walham circuit was restored by manual switching at 16.07hrs.
4 July, at Chickerell 400kV substation at :-				The Exeter-Chickerell 400kV circuit tripped 3 times during a severe lightning storm. After the first trip the circuit had to be restored manually following the loss of air from a circuit breaker at Exeter. Two further trips occurred but supplies were automatically restored in less than a minute. The Chickerell-Mannington 400kV circuit was out of service for planned maintenance work at the time.
02.21hrs,	10	31	5.2	
06.11hrs	0.5	27	0.2	
06.17hrs	0.5	27	0.2	
4 July, 04.30hrs at Tremorfa 275kV Tremorfa 275kV substation	144	107	256.8	The Aberthaw-Tremorfa-Uskmouth-Whitson 275kV circuit tripped during a severe lightning storm. The circuit failed to automatically reclose due to a persistent trip signal being sent from Aberthaw. This was reset and supplies were restored manually at 06.54hrs.
26 February, 10.50hrs at Templeborough 275/33kV substation	173	24	59.8	The Templeborough SGT1A-Brinsworth 1 and SGT3 – Wincobank circuits were tripped by transformer protection following a 33kV buried cable fault. Supplies were lost to the steelworks, BOC Gases and Yorkshire Electricity customers. Supplies were restored via SGT3 by remote control at 13.43hrs.
28 February, 11.50hrs Templeborough 275/33kV substation	120	3	6	The Templeborough SGT3 transformer was switched out of service to remove wind blown debris. SGT1A was out of service following the previous fault.
26 March, 10.31hrs at Hawthorn Pit 275/66kV substation	10	83	13.8	During the commissioning of new protection equipment tests were being carried out on SGT1, which was on outage, when an inadvertent trip of SGT2 occurred following the manual activation of trip relays. SGT2 was returned to service at 10.41hrs.

Anomalous losses

Incident Date, Time & Location	Incident Duration (Mins)	Max Demand Lost (MW)	Estimated Energy Unsupplied (MWh)	Comment
17 May, 06.09hrs at Tinsley Park 275/33kV substation	1	10	0.1 ?	The Brinsworth-Tinsley Park 1 275kV circuit was tripped at 06.09hrs following a Buchholz Gas alarm on Supergrid Transformer SGT1B, causing a loss of supply to the Steel Works. The customer had chosen to take supplies from a single transformer only. Supplies were restored via SGT1A.
27 January, 08.32hrs at Tinsley Park 275/33kV substation	1	67	1.1 ?	The Brinsworth-Tinsley Park 1 275kV circuit and Supergrid Transformer SGT1B was tripped by transformer protection causing a loss of supply to the Steel Works. The customer had chosen to take supplies from a single transformer only. Supplies were restored via SGT2B.
11 February, 14.51hrs at Alpha Steel 275/33kV substation	13	1	0.2	The Whitson-Uskmouth SGT2A/Alpha Steel SGT2B circuit tripped as a result of wind blown debris, causing a loss of supply to Alpha Steel. Supplies were restored at 15.04hrs by manual switching on site. The alternative supply to Alpha Steel, SGT4B, was off load due to an existing Alpha Steel 33kV cable fault.

APPENDIX F

APPENDIX G

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