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A Study of the Benefits of the Radio Teleswitch System and the Consequences of Replacement in the SHEPD Licence Area

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by

Mark Smith, Simon Wilson

Summary

The Radio Teleswitch System (RTS) was developed in the 1970s in response to growing peak-demands. These had been caused by the introduction of off-peak tariffs with fixed (and common across GB) changeover times. The tariffs were predominantly used by customers with electric storage-heating. The RTS was developed to manage the peak demand associated with this type of heating by allowing the charging times for storage heating to be changed and to allow more than one charging period per 24 hours. By the early 1990s several RTS-based load-management schemes were in place, predominantly in off-gas-grid areas.

The Scottish Hydro Electric Power Distribution (SHEPD) Licence Area has several of these areas and supplies a large customer-base of electric storage-heating. Recently, the digital switchover has left the future of the BBC's Long Wave (LW) radio transmission system in doubt; it is this system on which the RTS commands are distributed across GB.

In response to this and to inform the development of the Smart Metering System that is envisaged to replace the ageing RTS, Scottish and Southern Energy Power Distribution (SSEPD) has commissioned this study into the Benefits of the RTS and the Consequences of Replacement in the SHEPD Licence Area.

The study has found that, despite the age of the system, it is applying significant diversity to the installed base of storage-heating. If the RTS signal was to be lost for a period of greater than 7-days, or primary control of switching times was ceded to suppliers, this diversity would be lost, with very severe consequences for areas with significant storage-heating demand-bases.

The additional value of capital expenditure required to meet this additional demand is estimated as some £161M for the specific SHEPD locations examined and some £718M across SHEPD as a whole.

Glossary

BBC	British Broadcasting Corporation
BST	British Summer Time
CEGB	Central Electricity Generating Board
CTCU	Central Teleswitch Control Unit
DNO	Distribution Network Operator
E7	Economy 7
E10	Economy 10
EMTF	Energy-Management Task Force
ENA	Energy Networks Association
ESI	Electricity Supply Industry
FL	Fault Level
FM	Frequency Modulation
GB	Great Britain
GMT	Greenwich Mean Time
LF	Low Frequency
LPS	Lerwick Power Station
LW	Long Wave
LV	Low Voltage
MD	Maximum Demand
RTC	Real Time Clock
RTS	Radio Teleswitch System
SHEPD	Scottish Hydro-Electric Power Distribution
SHETL	Scottish Hydro-Electric Transmission Licence
SHC	Storage Heating Control
SMD	Simultaneous Maximum Demand
SMETS	Smart Metering Equipment Technical Specification
SSE	Scottish and Southern Energy
SVT	Sullom Voe Terminal
THTC	Total Heat Total Control
TPU	Tariff Programming Unit
VHF	Very-High Frequency

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1 Introduction

The Radio Teleswitch System is used to control the demand-profile of customers with electric storage-heating. This type of heating has been deployed mostly in the off-gas-grid areas of GB, as an alternative to other fuels. These are typically rural areas, which make up a significant proportion of the SHEPD Licence Area. The RTS was developed in the 1970s to diversify the charging of this type of heating and has been widely adopted in the SHEPD and other Licence Areas.

The RTS has been delivered by a high-reliability and integrity communications platform that reaches the whole of GB; the BBC 198 kHz LW transmission system. Since the 1970s the RTS has become a de-facto part of the management of load in different regions of SHEPD. Its high reliability has meant that it has not attracted attention; indeed its capabilities have been relatively unknown outside of certain regions. It has operated in the background and not required significant programme effort to maintain.

With the digital radio switchover, the future of the LW broadcasting system that the RTS uses to reach the whole of GB has been in doubt. In order to understand the implications of switching-off the RTS, SSEPD carried out an internal study and further to this, has commissioned EA Technology to independently carry out a study. The focus of this study is to investigate the extent to which the RTS is critical in SHEPD regions and to estimate the financial impacts of succession scenarios.

In this report there are references to the pre-privatisation arrangement and entities of the electricity industry. With the exception of the operation of the transmission network, before privatisation the Scottish electricity networks were owned and operated by the North of Scotland Hydro Board and the South of Scotland Electricity Board. On privatisation, the North of Scotland Hydro Board became Scottish Hydro Electric and after the purchase of Southern Electricity, became Scottish and Southern Energy (SSE). Scottish and Southern Energy Power Distribution (SSEPD) own and operate the distribution networks in the Scottish Hydro Electric and Southern Licence Areas. The wider company SSE owns and operates generation and also has an Electricity Supply business.

1.1 Scope of the Study

SSEPD has requested EA Technology to carry out an high level assessment to ascertain the potential impacts if the RTS service was to be withdrawn, with reference to impacts on the following:

- Generation;
- 33kV distribution network;
- 33/11kV primary substations;
- 11kV distribution network;
- 11kV/LV transformers; and
- Security of supply.

The impact of a number of succession scenarios was to be considered in the following six locations that are known to use the RTS:

- Islay;
- Skye;
- The Orkney Islands;
- The Shetland Islands;
- The Western Isles; and
- Dundee (as an example of a typical urban area).

1.2 Methodology

To allow for the completion of the study in the requisite timescale, a process was proposed and adopted that involved the detailed study of one or two regions. Details of the use of the RTS in different scenarios would provide information that would allow extrapolations to be performed for the other regions. The highest detail was given to Shetland, a medium level to Orkney and low levels to the remaining locations.

During the course of the project information was obtained that described details of the RTS itself, use of the RTS in six SHEPD locations, assessments of the amount of RTS controlled load and more. Many of these details are contained in this Report and its Appendices.

2 The Radio Teleswitch System

2.1 History and Development

The system was developed in the 1970s in response to a growing night-time demand peak that was due to the proliferation of electric storage-heaters and the forerunner of the 'Economy 7' tariff, the 'White Meter'. The White Meter tariff was delivered using mechanical time-switches and a two-rate meter ('low' and 'normal') that was installed in customers premises. The 'low' rate lasted 8 hours. The aim behind the tariff was to reduce the overall cost of generating electricity for electric heating, by shifting demand to the night and increasing run-times of generators.

The scheme was so successful that it altered the national load profile, creating the danger of a new night-time peak. The, then, Central Electricity Generating Board (CEGB) was charged by statute with delivering the cheapest possible electricity; which conflicted with the expensive and wasteful manner in which the demand-peak would be met. The Energy Management Task Force (EMTF) was formed by the CEGB to address the challenge. The EMTF identified the aims of the concept originally known as "Load Management" and today as "*Smart Metering*":

- Two-way communications to each customer;
- Tariff information sent to the customer;
- Load control for customer heating and cooling;
- Flexible tariff rates, up to half-hourly or spot-pricing;
- Return of meter readings
- Fraud prevention; and
- Remote connection and disconnection for non-payment / tenancy changes / ownership changes.

By this time, storage-heaters had become more efficient and needed only 7 hours of charge. The standard tariff switching-times of 00:30 to 07:30 were introduced and termed Economy 7 (E7), delivered by mechanical time-switches and two-rate meters.

Other countries had addressed the challenge of distributing load via ripple-control, which allowed load to be switched according to tariff changes. Those countries typically did not have the supply of gas present in the UK and the cost of providing ripple control in areas with small proportions of electric-heating was considered too great.

Radio transmission was thought to overcome this drawback and discussions were undertaken with the Post Office (who licensed radio transmissions). In 1976 the Post Office agreed that the Electricity Supply Industry (ESI) could work with the BBC in the provision of data transmissions and discussions started in 1977.

The BBC research department had developed and implemented radio data transmission for VHF and FM; similar ideas existed for LW transmission. The ESI funded its development and manufacturers (Sangamo, GEC Meters, Horstmann and Texas Instruments / L&G) were involved in making receivers and taking part in reception trials. LW radio transmissions were broadcast from Droitwich (Worcestershire), Westerglen (near Falkirk) and Burghead (near Elgin). Tests undertaken at Droitwich were extended to the three transmitters and the BBC arranged for their synchronisation so that the 'mush' areas, where signals were of roughly equal magnitudes, had stationary interference patterns. Reception could not always be guaranteed as signal conditions varied during the day, hence it was found necessary to repeat transmissions at intervals. These formed part of the specification of the system.

Three schemes had been investigated by the EMTF:

- Mains-borne two-way communications to individual customers;
- Telephone-borne two-way communications to customers with telephone lines; and
- One-way national radio coverage, with signalling for groups of customers.

The mains-borne system was beset by technical problems while the telephone operator wanted to charge more than the value of remote meter reading, so the radio-based system was recommended. National broadcasts to production Teleswitches began in Autumn 1983 and the full transmission hardware was completed in Spring 1984.

The Teleswitch offered several advantages over time-switches:

- More flexible load-control with multiple tariffs and tariff on-times;
- More reliable, especially after power cuts;
- Automatic change for BST/GMT;
- After a power failure, resets to the correct time and switching pattern; and
- Two load switches for independent control of space and water-heating.

2.2 System Overview

The system comprises:

- Teleswitches (approximately 3 million) in customer premises;
- A transmission network of three LW transmitters;
 - Droitwich (400kW, 213m aerial system);
 - Westerglen (50kW, 150m);
 - Burghead (50kW, 150m);
- The BBC Message-Assembler at Crystal Palace;
- The Central Teleswitching Control Unit (CTCU) that;
 - Provides the facility for DNOs to update switching times;
 - Keeps a model of the operating times of all Teleswitches and ensures that broadcasts are made at the correct times to keep the stored programmes up-to-date
- Company terminal equipment that interfaces to the CTCU
- Broadcast-monitors that interface to the CTCU and determine if broadcasts have been received.

The system was designed to prevent fraud, by virtue of the delivery of switching programmes in advance of switching times. Sending of switch-on and switch-off instructions would have made the device susceptible to fraud; by shielding of the receiver once it had been switched-on.

The system was designed with the following basic features:

- A free-running clock that synchronises to the BBC time-broadcasts;
- A memory for pre-programmed switching of tariffs and loads;
- Able to respond to load-shedding and load-boosting commands;
- A fall-back switching pattern set to the E7 tariff; and
- A random switching-time offset of ± 3 minutes that prevents all Teleswitches switching at the same instant.

Two types of message can be transmitted to the Teleswitches: “programme” and “immediate”. A “programme” message updates the internal switching programme for action later. An “immediate” message causes the immediate change of state of one or more contacts in the Teleswitch. The details required for development of a Teleswitch and most of the details about the decoding of LF data¹ are documented in BS7647². Connection diagrams for Teleswitches and Telemeters are included in Appendix 10.

According to the procedures outlined in DCUSA Schedule 8³, a DNO can issue various notices to declare a Load Managed Area (LMA). Reasons for declaration include where load management has been used to defer reinforcement and where an Energy Supplier-initiated change to the profile of load would cause concern for a DNO in meeting its security-of-supply obligations. It appears that for these reasons, when the industry was privatised, DNOs were given primary control over the switching-times of RTS customers. There is a pass-through arrangement for Energy Supplier-initiated changes that fall outside of LMAs.

¹ Certain details are said to be omitted for security reasons

² BS 7647, Specification for Radio Teleswitches for tariff and load control, 1993

³ Distribution Connection and Use of System Agreement, Version 5.3, October 2006

2.3 System Outlook

The outlook for the system as described below was obtained via conversations with the ENA and (unofficially) with Arqiva, that operates the LW radio transmission network on behalf of the BBC. Conversation records are included in Appendix 1.

At the inception of this project it was believed that a switch-off of the BBC LW radio transmission system was likely, the date for this being September 2013 and that any further extension would not be possible. The digital radio switchover process was underway and the phasing-out of the BBC LF transmission network was planned. This had led SSEPD to internally investigate the implications and to seek external review via EA Technology's engagement.

During the course of the project, conversations were held with Horstmann (the only remaining UK manufacturer of Radio Teleswitches), the ENA (as operator of the RTS on behalf of the GB DNOs) and Arqiva.

The outcome of these conversations is that it now seems very unlikely that the system will be switched off in 2013. Notwithstanding the effect on the RTS, the effect on BBC Radio 4 listeners would probably be undesirable for the BBC.

There are three transmitters used for LW transmission: Droitwich, Westerglen and Burghead. The Droitwich transmitter still uses valve technology and it is believed that only 10 remain; these are kept carefully. Life-extension had been thought possible by running the transmitter at half-power (normally, two parallel-amplifiers are used). Tests were carried out during the Test Match Special and it appears that no complaints were received. In any case, this would not affect SHEPD since the Westerglen and Burghead transmitters serve this area. Reception was tested by certain ENA members and carried out across 5 days to prevent possible reversions.

Possible life extension by running at reduced power is thought to be in excess of 2016. There are approximately 3M Teleswitches in GB⁴.

2.4 Use of the RTS in SHEPD

2.4.1 Deployment and History

The use of the RTS dates from around 1993 when it was introduced for load management on Shetland, in response to growing peak demands from electric storage heating used with off-peak tariffs. Specific group-codes were allocated for load-management that, on the older types of Teleswitches and telemeters, were set by switches hidden in the meter enclosure. More modern types such as the Horstmann "K-series" were configured using a hand-held programmer on-site or by using a computer connected to a communication port and programmed before installation.

Demand has increased since then and the RTS switching-times have been adjusted twice since deployment on Shetland. The RTS is thought to have been used around 8 years ago on an emergency basis, when margins of supply were tight. Shetland remains an islanded network and there is an annual review of tariff switching-times. The most recent change, several years ago is said to have reduced peak demand by about 4 MW, the equivalent of one generating-set.

⁴ ENA, RTS Meters Company Responses, 6/6/11

Other regions followed Shetland, with Orkney apparently receiving an RTS scheme in 1994. At that time Orkney was supplied via a single 20 MVA submarine cable and supplementary diesel generating-sets. Implementing the RTS scheme involved replacing around 2000 White-Meter time-switches; these were assigned to two specific Orkney group-codes. It appears that there was use of RTS equipment before 1994, since it was reported that in 1990, a problem arose due to the first tele-switches not having randomised time-offsets. The effect of this was to cause a step-change in voltage of 6-8%. Tap-changers moved through 4-5 steps at 10:00 and the effects were noticeable.

To mitigate this a new version of the Teleswitch was developed (specifications enshrined in BS7467:1993), the Teleswitches were changed to the (then) new versions with ± 3 minute offsets, that spread the load-steps, and tap-changer delays were reduced from 2 minutes to 30 seconds. It is believed that a small number of old mechanical time-switches are still in use.

When Orkney received a second submarine cable, local generation was only required to run during (n-1) situations and load-management was not considered as important. Tariff switching-times are not thought to have been changed since 2000. Shetland, Orkney, the Western Isles and the SSEPD control room were all known to have RTS computers to alter switching times.

Other SHEPD regions where the RTS has been deployed include the Western Isles (Harris, Lewis, N. and S. Uist), Islay, Skye and urban areas e.g. Dundee. For this project, those locations were not investigated in detail (an extrapolation of effects has been undertaken).

2.4.2 Tariffs and Group Codes

Storage-heating customers have been assigned to group-codes based upon their agreed tariff and region. There are currently 58 group-codes assigned to the Scottish Hydro Electric Licence Area, though (according to records known to be inaccurate) 11 have fewer than 50 customers.

By way of example, Shetland group-codes include 8 "Static" tariffs that can have the switching-times of the space-heating contactor changed. For these tariffs, the whole of the customer's demand changes to the low-rate according to the tariff switching-time. These customers require notification if there is to be a change to the tariff-times. For these customers, water and space heating are switched-on and off together.

Shetland also has two Total Heat Total Control (THTC) tariffs classed as "Dynamic", which means that the switching-times can be changed without notification. A minimum of 5 hours charge-time is given for space-heating, 5.5 hours for water-heating. These tariffs are altered according to weather and to maintain island load within distribution or generation capacity.

The THTC tariffs provide the main means of load-control. Customer space and water heating are supplied with individual switching programmes to increase diversity; the low-rate tariff is applied whenever these are active (excepting 'boost' control). THTC tariffs were introduced in 2002 and, to the extent of the investigations detailed here, form the main part of RTS load-management in SHEPD. Although there is the facility to change tariff-times according to season, it appears that this has only been used for the Orkney Isles.

2.4.3 Teleswitch Configuration Settings

According to discussions with Horstmann and Geoffrey Hensman (the inventor of the RTS), Teleswitches could be pre-configured at manufacture. The most notable electricity-network configuration settings are those that control the action of the meter if the RTS signal is lost. There are three settings that control this “reversion” to a pre-configured programme of switching-times known as the “fall-back” programme:

- 1) Revert after 24 hours;
- 2) Revert after 7 days; and
- 3) No revert.

Horstmann identified that all the K-series telemeters supplied to SSE were pre-configured to revert after 7 days. Information on earlier versions was not found. For K-series meters there were two unique fall-back programmes supplied at manufacture that caused water and space heating to switch-on for the times and durations presented in Appendix 7. These did not bear any resemblance to the programmes used on Shetland.

The combination of 7-day reversion and only two fall-back programmes (compared to the 58 group codes in use today) would have disastrous effects on networks with high proportions of storage-heating, if the RTS was switched-off for longer than 7 days⁵. The best setting for load-management would be ‘No revert’. Teleswitches would continue to deliver the last-stored programme; unequal clock-drifts would cause these to change over time. While it would seem most likely that this would reduce impact on networks by smoothing out load-steps, the possibility remains that the 7-step randomisation might become (at least temporarily) a reduced number of steps, causing voltage-control problems.

2.4.4 Current Utilisation

Of the regions investigated in detail for this project (i.e. Shetland and Orkney), only Shetland has a process that involves the consideration of tariff switching-times for managing load. On Orkney it appears that current staff is not aware of the functionality to reallocate load that would be beneficial for contingencies.

As the technology is ageing, RTS meters are being recycled from one area to another. The versions that can have their group codes changed by internal switches are said to be most desirable since computer-based configuration equipment is now out-of-date⁶. Anecdotal reports suggest that this recycling means that a mix of regional group codes will be present in any SHEPD area.

SSE R&D have analysed the past 2-years’ of Telemeter orders, finding that only 9 different group-codes are being specified compared to the 58 available. Telemeters are not reprogrammed after order. Furthermore, analysis of the SSEPD database of RTS meters showed that 111 group-codes were present (half of these are not SHEPD codes). These facts mean that the profile of demand is not being maintained. The amount of new electric storage-heating load is 20 MW of capacity per year at an average of 2,175 Telemeters over the two years studied by SSE R&D. If this were allocated as per the average diversity

⁵ The detailed analysis undertaken for Shetland as part of this study showed that network peak load would double in the fall-back case and that the supply could not be maintained with the current generation and distribution assets

⁶ Investigations carried out for this project revealed that Horstmann have software that will run on XP-based PCs

evaluated for Shetland, it would add only 10 MW to peak-load⁷, with the potential for further optimisation.

Real-Time Clock (RTC) meters were present as meter-types in a set of data about RTS meters that was received from SSE Supply. RTC meters have the facility for multiple high and low-rate periods and to control load in the same manner as RTS meters, but without the facility for programme times to be changed remotely and without the “immediate” command functionality. During this project, information was not received that detailed how new customers or those changing tariffs, were assigned meter-types or switching-times. It is presumed that RTC meters are better for the avoidance of fraud. There is some information on the internet that appears to show the changing of high and low-rates⁸ for RTS meters.

Knowledge regarding the capability and use of the RTS to manage load is now held by a few individuals and is at risk of being lost.

2.5 Succession

Modern-day Smart Metering technology has been developed that can deliver the aims of the “*Smart Metering*” concept that was understood at the time of the development of the RTS. Smart Metering has now been mandated by the EU; 80% coverage by 2020. This technology is widely believed to supersede the RTS. For this technology to efficiently and economically replace the RTS, its functionality must be at least that delivered by the RTS. This means not only the ability for suppliers to update programmes remotely, but also the ability for network operators to diversify switching programmes to suit the operation of networks.

At the time of writing the Smart Metering Equipment Technical Specification is undergoing a consultation on Version 2 of the specification⁹. It is this version that includes proposed details of the resolution of switching programmes (half-hourly) and of the time-randomisation that should be applicable for connected load.

3 Scenarios for Evaluation

At the inception of this project the following scenarios were identified for analysis of their impact on SHEPD:

1. The RTS is shutdown in 2013, with no replacement being available (no updates can be sent to meters);
2. Primary control over load-management is ceded to Energy Suppliers; and
3. An enhanced load-management service, to be delivered over the Smart Metering System.

The bulk of the work has been delivered to answer the first question with details about the impact on distribution networks, requirements for generation capacity and additional running costs. The second is answered by reference to the information garnered during this approach.

⁷ Shetland demand doubles under the fall-back (no-diversity) condition. See Section 4 and Appendix 5 for details.

⁸ Available at <http://www.youtube.com/watch?v=fmQcQemcc1U>, accessed 10/09/2012

⁹ Available at <http://www.decc.gov.uk/consultations/Default.aspx?status=0&area=43>, accessed 10/09/2012

The third is illustrated with reference to a flat load profile. The latter illustrates the optimum allocation of load without considering the limitations. With individually-addressable Smart Meters deployed with a tariff similar to THTC (i.e. space and water-heating is always charged at the low-rate) something close to this approximation ought to be achievable as long as existing non-THTC customers can be encouraged away from their existing tariffs onto new ones. The results of all three are presented in Section 4.

The remainder of this Section 3 presents the Methodology used to determine the Results, the data employed and comments regarding the quality of the data employed.

3.1 Methodology

The objective is to provide a model of the load on Shetland if the RTS was to enter and continue to operate in fall-back mode and with this information to carry out the required impact assessments on Shetland and by extrapolation on Orkney; Western Isles; Skye; Islay and Dundee.

To achieve this, the following steps were undertaken:

1. Model primary substation load by normalising the demand “PI data” recorded at substations for the Winter day of maximum demand;
2. With the numbers of RTS customers on each primary substation, their group codes and relevant switch on/off times, model the RTS element of the substation PI data and the base (non-RTS) element.
3. With the numbers of customers on each primary substation, their fall-back group codes and relevant switch on/off times, model the fall-back group load for each substation, add this to the base (non-RTS) load element of the normalised substation load data to arrive at the overall normalised fall-back load for each substation.
4. Calculate relevant Simultaneous Maximum Demands (SMDs) for:
 - a. Generation, by aggregation of primary substation SMDs;
 - b. Distribution network circuits, by carrying out load-flow analysis based on substation loadings on individual network segments;
 - c. Primary substations, by calculating substation MD and calculation of load-factor (MD/Transformer Capacity);
 - d. 11kV distribution network, by calculating load per circuit and comparing to circuit rating¹⁰;
 - e. 11kV/LV transformers, by calculation of maximum RTS load under fall-back conditions and comparing to nameplate rating;
5. Calculate the impact of a change in the class of demand according to P2/6 (e.g. the requirement for an additional supply at a substation), for 4(a), 4(b) above¹¹ and P2/6 “Class of Supply C”;

¹⁰ The circuit rating data was unavailable and the length of overloaded 11kV network was calculated by multiplying the length of overloaded 33kV circuit on Shetland by the ratio of 11kV circuit length to 33kV circuit length within the whole of SHEPD

6. By aggregation and proportioning assess the impact on the electricity network in the required areas: Orkney, Western Isles, Skye, Islay and Dundee.

3.2 Data Used and Data Quality

Data used for the project can be grouped into the following categories:

- RTS data;
 - Fall-back programmes;
 - Details of meter and system operation;
- RTS customer data;
 - Meter-Point Administration Numbers (MPANs), meter-types, RTS group-numbers and locations;
 - Network Reference Numbers (NRNs) for each MPAN allowing the network location (e.g. primary and transformer) to be determined;
 - Typical installed capacities;
- Network load data;
 - Recorded loads from primary substations ("PI data"); and
 - Network diagrams and other geographical information.

Initial investigations into network load profiles and comparisons with estimations made using RTS data sources showed correlations at individual substations to be imperfect. As a result, SSEPD undertook surveys of installed group-codes in Dalwhinnie (mainland near Inverness), Dundee (mainland), Perth (mainland) and on the Shetland Island of Unst. For Unst, approximately 80% of group-codes were recorded correctly, while for the mainland areas most were erroneous. This is thought to be due to the greater importance and knowledge of load-management on the Shetland Islands.

Overall, there have been several areas in which judgements and approximations have been necessary. Amongst others, these are identified as opportunities for further work in Section 7. The following notes have been made that apply to the detailed investigation that was performed for the Shetland Islands and included in Appendix 5.

Substation Load Profiles - Time synchronisation across substation data

PI data received from SSEPD was not time synchronised across primary substation sites, nor synchronised to RTS switching times. Granularity of RTS switching times is no better than 15 minutes always occurring on a quarter hour boundary plus or minus the RTS offset of ± 3 minutes (7 steps) built into the RTS programmable switching time. Accordingly the load profile was interpolated from PI data using software and aligned to the switching times.

Substation Load Profiles - Missing data

Certain PI data was missing and had to be made up from similar substation PI data.

Substation Load Profiles - Questionable data

Data had not been recorded for the Firth substation.

¹¹ SSE has a P2/6 exemption that applies to certain classes of demand, further information has been requested

Water-Heating Load Profile

The water heating load profile has been calculated based on a cylinder size of 100 litres (retail cylinder capacities range from 50 to 200 litres), an intake water temperature of 10°C, a tank thermostat setting of 60°C and a heating element rating of 3kW.

Space-Heating Load Profile

The space-heating load profile is based upon load switching-on for the duration of the group code switch-on time mitigated by the starting temperature of the storage medium, assumed to be normally distributed between the ambient temperature and fully-charged. The average switch-on load is assumed to be 6kW per RTS customer.

Distribution of Customers to Fall-back Group Codes

The distribution of RTS customers to particular Fall-back Group codes is unclear. The Fall-back Group Code switching patterns are not symmetrical and the assumption of a 50/50 percent split does not give either the lowest or highest increase in MD. By empirical means the two extremes of MD, 'best case' with the lowest increase in MD and 'worst case' with the highest increase in MD were calculated.

Allocation of Customers to Group Codes

To simplify the analysis, group codes with less than 50 customers were ignored in the RTS normal operation mode. Under Fall-back mode all RTS customers were included in the analysis.

Distribution 11kV Circuit Ratings

This data was not available.

Distribution Network 11kV/LV Transformers

The data for 11kV/LV transformers was provided. Whilst calculations have been performed using this source; inspection has shown that there are many errors, the obvious ones being missing data, calculation errors and no customers being connected to the relevant transformer.

By comparison with the RTS Group Code data there are situations where the number of RTS Group Codes on a transformer exceeds the number of connected customers in the transformer data.

There are also areas in the data where lack of format and content validation has allowed invalid data to be input.

4 Scenario Results

This Section presents the results of the network and financial modelling processes. Details of the processes and approaches used are included in Appendices 5 and 6. Results have been assessed from the in-detail study of the Shetland Islands example with extrapolations for the other regions.

4.1 Switch-off of the RTS

Results from the study of a potential switch-off of the RTS, with reference to the different asset classes of the locations are presented in Table 1 over-page, with conversion into financial equivalents in Table 2. Conversions are based upon costs supplied by SSEPD and supplemented according to regulatory asset values (see Appendix 5). The total cost of assets required to meet the RTS switch-off scenario is estimated as some £161M in the SHEPD locations investigated. These locations contained 26k of the 116k RTS customers supplied by SSE. Extrapolating across the whole of SHEPD according to the ratio of customer numbers yields an estimate of $116k / 26k * £161M = £718M$. The following Sections discuss the Results.

4.1.1 Shetland

Shetland has approximately 12,500 customers with just over 8,000 using RTS to control their water and space heating.

On Shetland the tariff implementations are no longer recognisable when compared to the original Economy 7 type tariff. The customers space and water heating load is controlled by the Radio Teleswitch which switches load on or off dependent on a group code programmed with up to four on and off periods which can be different for water and space heating. The tariff and corresponding group code implementations are now such that there is no single period of the day on Shetland when some aspect of island load does not contain a RTS element of load.

Table 1: SHEPD Impacts (Networks)

Location	Generation	33kV Distribution Network	33 / 11 kV Primary Substations	11kV Distribution Network	11kV / LV Secondary Substations
Shetland	72 MW Generation	70 km	6	241 km OHL 53 km UGC	226 RMU 555 PM/GM
Orkney	48 MW Generation	Detailed investigation required	4	137 km OHL 30 km UGC	128 RMU 315 PM/GM
Western Isles	36 MW Generation 20 MW via Sub-Cable	Detailed investigation required	8	122 km OHL 26 km UGC	115 RMU 282 PM/GM
Islay	No Impact	Detailed investigation required	4	90 km OHL 20 km UGC	84 RMU 206 PM/GM
Skye	No Impact	Detailed investigation required	3	64 km OHL 14 km UGC	60 RMU 147 PM/GM
Dundee	No Impact	Detailed investigation required	0	Possible	Possible

Table 2: SHEPD Impacts (Financial)

Location	Generation (£M)	33kV Distribution Network (£M)	33 / 11 kV Primary Substation (£M)	11kV Distribution Network (£M)	11kV / LV Secondary Substation (£M)	Total (£M)
Shetland	31	6	5	16	7	65
Orkney	14	0	4	9	4	31
Western Isles	25	0	7	8	3	44
Islay	0	0	4	6	3	12
Skye	0	0	3	4	2	9
Dundee	0	0	0	0	0	0
					SHEPD Locations Total	161
					SHEPD Total	719

The situation on Shetland is unique in other aspects. The overall network is electrically isolated from the mainland and must independently provide for all its electricity needs through generation scheduling and despatch, transmission and distribution particularly when complicated by the peculiarities of geographic dispersal, mix and age of assets. Generation is managed between Lerwick Power Station A and B, non-SSE generation at Sullom Voe Gas Terminal and Burradale Wind Farm. The current Winter/Summer maximum demands are 47 MW and 22 MW respectively.

If the RTS system was withdrawn and reverted to Fall-back mode the following changes would occur to the Shetland network:

- Generation
 - The island MD would increase to 102 MW.
 - An additional 72 MW of island generation would be required with a new 33/11kV - 3 x 38 MVA Primary substation at Lerwick
 - Generation scheduling and despatch would have to cope with four relatively short duration large demand increases/decreases per day. These spikes in demand would be of the order of 70-75 MW over a seven-minute period.
 - The existing generation plant if retained would have a massively increased stop/start duty placed upon it with consequential increase in operating expenditure and decrease in life expectancy. With the generation assets already beyond economic life such a large increase in duty cycle would question the adequacy of the island's security of supply.
 - A lower minimum demand would occur. This may cause network stability issues particularly scheduling generation between Lerwick Power Station, Sullom Voe Gas Terminal and Burradale Wind Farm which along with other considerations has been highlighted in a study by the University of Strathclyde²⁰.
- 33kV Distribution Network Capacity
 - The 33kV Distribution Network would need reinforcement to carry the demand requirements to the 33/11kV Primary Substations as well as to provide for P2/6 security of supply requirements.
- 33/11kV Primary Substations
 - Increased demand will cause overload of Primary Substation 33/11kV transformers with the need to upgrade six 33/11kV transformers across the island.
- 11kV Distribution Network
 - Increased load on the 11kV Distribution Network will require overlay of 11kV cables or re-conductor/rebuild of 11kV overhead lines.
- 11kV/LV Secondary Transformers
 - A total of 555 11kV / LV secondary transformers including switchgear will require replacement for increased MD placed on them – 329 pole-mounted and 226 ground-mounted.

4.1.2 Western Isles

The Western Isles; Lewis, Harris and Uist have approximately 4100 customers using RTS to control their water and space heating.

The overall island chain is electrically split from each other with Harris & Lewis having its own generation and submarine supply cable from the mainland and Uist also.

If the RTS system was withdrawn and reverted to Fall-back mode the following changes would occur to the Western Isles networks:

- Generation Capacity
 - The island MD would increase to 52 MW.
 - Whilst generation and submarine cable capacity on both groups would be sufficient to support load, loss of either would mean group demand could not be met.
 - Under single circuit outage conditions there would be a worst case shortfall in supply of 6 MW on Harris/Lewis and 5 MW on Uist.
 - Capacity needs to be increased by installation of additional submarine cable(s) and by on-island generation.
- 33kV Distribution Network Capacity
 - The 33kV Distribution Network would need reinforcement to carry the demand requirements to the 33/11kV Primary Substations as well as to provide for P2/6 security of supply requirements.
- 33/11kV Primary Substations
 - Increased demand will cause overload of Primary Substation 33/11kV transformers with the need to upgrade eight 33/11kV transformers across the island
- 11kV Distribution Network
 - Increased load on the 11kV Distribution Network will require overlay of 11kV cables or re-conductor/rebuild of 11kV overhead lines.
- 11kV/LV Secondary Transformers
 - A total of 282 11kV / LV secondary transformers including switchgear will require replacement for increased MD placed on them – 167 pole-mounted and 115 ground-mounted.

4.1.3 Orkney

Orkney has approximately 4600 customers using RTS to control their water and space heating.

Maximum demand on the island is around 34 MW with RTS operating normally.

The island has its own generation including substantial renewables and is also supplied from the mainland by two submarine cables, one rated at 20 MW and the other at 30 MW. Generation on the island is provided by Kirkwall Power Station which has an effective continuous output of 14.5 MW.

If the RTS system was withdrawn and reverted to Fall-back mode the following changes would occur to the Orkney network:

- Generation Capacity
 - The island MD would increase to 58 MW.
 - Whilst generation and capacity from both submarine cables would be sufficient to support load, loss of generation at Kirkwall or either of the submarine cables would result in insufficient supply capacity.
 - Under first circuit outage conditions there would be a worst case shortfall in supply capacity of 24 MW.
 - Capacity needs to be increased by installation of additional submarine cables and by on-island generation.
- 33kV Distribution Network Capacity
 - The 33kV Distribution Network would need reinforcement to carry the demand requirements of the 33/11kV Primary Substations as well as to provide for P2/6 security of supply requirements.
- 33/11kV Primary Substations
 - Increased demand will cause overload of Primary Substation 33/11kV transformers with the need to upgrade four 33/11kV transformers across the island
- 11kV Distribution Network
 - Increased load on the 11kV Distribution Network will require overlay of 11kV cables or re-conductor/rebuild of 11kV overhead lines.
- 11kV/LV Secondary Transformers
 - A total of 315 11kV / LV secondary transformers including switchgear will require replacement for increased MD placed on them – 187 pole-mounted and 128 ground-mounted.

4.1.4 Islay

Islay has approximately 3000 customers using RTS to control their water and space heating.

The overall island chain has limited generation which is only used in standby mode. The island is supplied by two transformer infeeds from Port Ann and alternatively via normally open circuits from Clachan or Dunoon.

If the RTS system was withdrawn and reverted to Fall-back mode the following changes would occur to the Orkney network:

- Generation Capacity
 - The island MD would increase to 38 MW.
 - Under first circuit outage conditions the supply capacity remains sufficient.
- 33kV Distribution Network Capacity
 - The 33kV Distribution Network may need reinforcement to carry the demand requirements to the 33/11kV Primary Substations as well as to provide for P2/6 security of supply requirements.
- 33/11kV Primary Substations
 - Increased demand will cause overload of Primary Substation 33/11kV transformers with the need to upgrade four 33/11kV transformers across the island
- 11kV Distribution Network
 - Increased load on the 11kV Distribution Network will require overlay of 11kV cables or re-conductor/rebuild of 11kV overhead lines.
- 11kV/LV Secondary Transformers
 - A total of 206 11kV / LV secondary transformers including switchgear will require replacement for increased MD placed on them – 122 pole-mounted and 84 ground-mounted.

4.1.5 Skye

Skye has approximately 2100 customers using RTS to control their water and space heating.

The island is principally supplied via two split 30 MVA 132/33 kV infeeds at Dunvegan and Broadford substations. The island has a reasonable amount of renewable energy generation, particularly wind at Storr Lochs.

If the RTS system was withdrawn and reverted to Fall-back mode the following changes would occur to the Orkney network:

- Generation Capacity
 - The island MD would increase to 27 MW.
 - Under first circuit outage conditions the supply capacity remains sufficient.
- 33kV Distribution Network Capacity
 - The 33kV Distribution Network may need reinforcement to carry the demand requirements to the 33/11kV Primary Substations as well as to provide for P2/6 security of supply requirements.
- 33/11kV Primary Substations
 - Increased demand will cause overload of Primary Substation 33/11kV transformers with the need to upgrade three 33/11kV transformers across the island
- 11kV Distribution Network
 - Increased load on the 11kV Distribution Network will require overlay of 11kV cables or re-conductor/rebuild of 11kV overhead lines.
- 11kV/LV Secondary Transformers
 - A total of 206 11kV / LV secondary transformers including switchgear will require replacement for increased MD placed on them – 122 pole-mounted and 84 ground-mounted.

4.1.6 Dundee

Dundee has approximately 4300 customers using RTS to control their water and space heating.

The network is principally supplied via two 60 MVA 132/33 kV infeeds. The network has reasonable amount of renewable generation particularly 4MW wind and 10.5MW biomass.

If the RTS system was withdrawn and reverted to Fall-back mode the following changes would occur to the Dundee network:

- Generation Capacity
 - The regional MD would increase to 56 MW.
 - Under first circuit outage conditions the supply capacity remains sufficient.
- 33kV Distribution Network Capacity

- The 33kV Distribution Network may need reinforcement to carry the demand requirements to the 33/11kV Primary Substations as well as to provide for P2/6 security of supply requirements.
- 33/11kV Primary Substations
 - Capacity of existing Primary Substations is sufficient.
- 11kV Distribution Network
 - Increased load on the 11kV Distribution Network may require overlay of 11kV cables or re-conductor/rebuild of 11kV overhead lines.
- 11kV/LV Secondary Transformers
 - Increased load on the 11kV/LV secondary transformers may require replacement of a number of units.

4.2 Loss of Primary Control of Switching Programmes

Although the RTS was developed when the industry was vertically-integrated, diversification of tariffs can be construed to have been implemented by the Supply industry (to shift demand to lower-cost generation), yielding White Meter, Economy 7 and more recently Economy 10 tariffs. The diversification of tariff switching-times can be construed to have been implemented by the distribution industry (evidenced by the use of multiple switching programmes for the same tariffs in SHEPD) and that, to the extent of the enquiries made for this project, these times have not been questioned.

Based on the hypothesis that Suppliers would, if given primary control, simplify the system to remove diversification of individual tariff switching-programmes, a calculation of the impact on peak load can be made. No diversity would be applied in this case. If every customer was on the Economy 7 tariff and this was the only off-peak tariff, then about 9 kW per-customer would be required if space and water-heating were switched at the same time (this is equivalent to the Economy 7 scenario investigated for Shetland presented in Appendix 5 and results in a more-than doubling of the peak load to 102 MW).

If two tariffs were available as today (e.g. Economy 7 and Economy 10) then, if distributed in equal proportions with no overlap, these would halve the peak load of the storage heating customers to 4.5 kW. Unfortunately, overlap does exist in the periods 04:30 – 07:30 and 23:30 – 00:30¹². Hence it is assessed that the loss of primary control would be equivalent to activation of the Fall-back programme, i.e. the requirements are the same as those presented in the previous Section.

¹² A useful compilation of E10 times is available at <http://www.kensaengineering.com/Library/Fact-sheets/FactSheet-SSEEconomy10Tariff.pdf>, accessed 10/09/2012

4.3 An Enhanced Load Management Service

The optimum load profile from the point-of-view of the provision of network capacity is a flat profile, i.e. the minimum load is equal to the maximum. For the Shetland example, the reduction in peak load if this approach can be followed would be approximately 20%, the equivalent of two generating-sets. Theoretically this could be approached using the RTS if every customer was assigned dynamic (THTC-type) tariffs and a full use of programme diversity via group-codes was in-place. It would probably also require the use of the RTS "immediate" commands in conjunction with a selected base of customers, to fine-tune demand profiles. These approaches would prove complicated to set-up but could be achieved using an RTS-linkage to Active Network Management equipment. It would probably need visits to a significant proportion of RTS customers to set-up; visits that would be repeated when Smart Meters require installation. Nevertheless, benefits could be realised using the technology available today.

The Smart-Meter load-control variants will have the two-way communications necessary for frequent tariff-programme updates, measurements of connected load and in conjunction with a THTC-type tariff (i.e. all storage-heating is supplied at the low-rate) would be a powerful load-management tool in all storage-heating areas. Such efficient use of network assets would only be possible if DNOs retain primary control of switching-programmes in Load Managed Areas.

If the same 20% reduction in peak load could be applied across SHEPD's storage-heating locations, network reinforcement could be delayed. Further work would be required to identify where reinforcements were planned and to tailor the load-management required for different regions.

A rough indication of the potential value of this approach in mitigating reinforcement in the SHEPD locations can be calculated by:

1. Calculating the approximate aggregate capacity being met for the SHEPD locations investigated $102+59+52+27+56+38 \text{ MW} / 2^{13} = 167 \text{ MW}$;
2. Dividing the £161M cost of meeting additional demand for those locations by the additional demand met = $£161\text{M} / 167 \text{ MW} = £1\text{M} / \text{MW}$; and
3. Finding the value for the SHEPD locations by multiplying 167 MW by 20% and $£1\text{M} / \text{MW} = £33\text{M}$;
4. Finding the value across SHEPD by extrapolation according to numbers of RTS customers = $116\text{k} / 26\text{k} * £33\text{M} = £147\text{M}$

An estimate of the value across SHEPD can be determined by extrapolation according to the ratio of the total number of RTS customers in SHEPD to those in the locations investigated: $116\text{k} / 26\text{k} * £33\text{M} = £147\text{M}$

At typical load-growth of 1% per-annum, this would be realised over 20 years, i.e. approximately £7M per annum across SHEPD. A brief survey of transformer load profiles by SSEPD identified a number of areas where load management would be applicable. A trial is proposed for the winter, aimed at reducing load on the Inverary transformer by reallocating group-codes.

¹³ Existing demands are approximately half of the Fall-back scenario for which the costs have been presented

4.4 P2/6 Implications

The SHEPD Licence Area has an exemption from the application of ER P2/6 which from the investigations carried out for this project and empirical evidence, appears to be applied to “Class of Supply B” at primary substations and 11kV distribution feeder level¹⁴.

5 Options for Succession

5.1 Mitigation of RTS Shutdown

At the inception of the project several mitigation options were proposed for evaluation. During the course of the project other options have become clear and are better suited for the purpose, these being:

- Reconfiguration of Teleswitches and Telemeters to the ‘No-Revert’ setting;
- Life-extension of the existing transmission network;
- Use of the two Scottish transmitters separately to Droitwich; and
- An advanced rollout of the Smart Meter load-control variant.

5.1.1 Reconfiguration to No-Revert

The selection of No-Revert would allow Teleswitches to continue to deliver the last-stored programme. Since these programmes have (for the regions where load-management is critical) been developed over time to apply suitable diversities, then this is the best setting. There would of course, be no option to update programmes other than by physical visits to the properties in question. This could in theory be achieved by meter-readers using a computer terminal. Although Horstmann can manufacture a hand-held programmer (“Tariff Programming Unit”, see Appendix 9), this appears to set group codes only, so a new design would be required.

Programme times would change according to clock-drift, so that over time, load-steps would have lower ramp-rates. Clock-drift for Teleswitches and Telemeters is unknown, though could be relatively high due to their age and because they receive regular time-updates over the RTS. A dangerous condition does occur if there was a power-outage, this being that the meter-times would be reset to 02:00 on the 1st April. For Shetland, this would mean that approximately one-half of the storage-heaters would charge when the supply was restored – a demand of 53MW (at 9kW space and water-heating per-customer plus the ‘non-RTS’ load of the island equivalent to 3kW per RTS-customer). This would be delivered in 7-steps starting approximately 3-minutes after restoration (duration of Teleswitch start-up sequence) and lasting for 12 minutes (the randomisation time applied before programme-instructions are received from the RTS).

The No-Revert setting could likely be applied to a high proportion of RTS Teleswitches and Telemeters over a couple of years, if delivered by meter-readers. Making the gross assumption that such a task, using a purpose-designed tool, would double the cost of meter-reading and that meter reading was today accomplished at £9 per-meter per-year¹⁵ then the cost of this option would be around 116,000 (RTS meters) * 2 * £9 = £2.1M.

¹⁴ Further details have been requested

¹⁵ NERA Economic Consulting, Energy Supply Margins: Update June 2010, June 2010

5.1.2 Life-extension of the existing LW radio transmission network

Life extension is thought to be possible until at least the early part of the Smart Meter rollout. Since the existing system has been very reliable (almost no failures reported, see Appendix 1) this is an attractive option that the reduced-power tests have so-far shown to be feasible. The existing system, managed by the ENA costs the SHEPD area £113k per annum to maintain, with a further £25k per annum necessary for the SSE Control Room to administer the system.

5.1.3 Use of the Scottish LW radio transmitters

The BBC licence for LW radio transmission on 198 kHz bundles voice and data together. Anecdotaly, the BBC would not want to divide-up the radio transmission system in case the broadcast facilities fell into the hands of a competitor. An option might remain to have Ofcom separate the voice and data licences. This could allow the Scottish transmitters to be operated separately to deliver data to SHEPD areas. An amount of work would be required to change the configuration of the existing system. For the purposes of this project, an initial enquiry has been made regarding the feasibility of this approach.

The opinion received (see Appendix 1) was that this should be carried out as a whole-industry approach and in response to such information as a statement from the BBC about the future of LW transmission. Such a statement could be obtained by the tabling of a question in Parliament, though such a public discussion might not suit the interests of the BBC.

For the purposes of analysing the costs of this approach, any cost reduction from the £750,000 total-cost of the RTS to ENA members due to the reduction in radio transmission would probably be negated by the extra work involved to change the system and obtain separate licences, at least in the first year.

Furthermore, the reduced number of Licence Areas that the broadcasts would reach would mean an increase in the share of costs that SHEPD currently bears.

5.1.4 Advance rollout of the Smart Meter load-control variant

The government is leading the development of the Smart Meter rollout strategy and the specification of the Smart Meter itself. Specifications for the second version of the Smart Metering Equipment Technical Specification (SMETS) are now in consultation. This version has defined the resolution of programme times to be half-hourly and there is an appropriate randomisation-time applied to reduce the impact of load-steps (as discussed in Section 5.2).

Since Smart Meters will be mandatorily installed, it is assumed that there will not be a cost attributable to an advanced rollout of the load-control variant in electric-heating areas. Indeed, application on one of the Islands could provide a very useful test-case¹⁶.

5.1.5 Summary of options

The overriding need is to secure the operation of SHEPD networks. Today there appears to be a negligibly-small risk of the RTS being unavailable in a SHEPD area for longer than 7-days; such a failure has not been evidenced. In the event that this occurs, then it has been discovered that, due to reversion to fall-back programmes, operation of the network in

¹⁶ The SSEPD project "Northern Isles New Energy Solutions" is understood to be investigating smart control of storage heating.

SHEPD would become difficult (greater peak-demands and, because the distribution of fall-back-programmes is unknown, the need to keep a lot of plant on spinning reserve to meet potential peaks on the eighth day after transmission ceased).

The best option would it seems, be a combination of the approaches outlined; life-extension of the existing transmission system (with the appropriate directions followed to split voice and data licences if problems arise) until an advanced rollout of the Smart Meter load-control variant can be carried out in storage-heating areas.

Whether in addition, the No-Revert setting should be applied to, at least a significant sample of Telemeters, is open to debate. A recommendation for further work would be to try to ascertain the probability of a 7-day failure occurring and to assess whether this risk should be borne or mitigated.

5.2 Randomisation Requirements for a Successor to the RTS

This Section considers how the design of the RTS has ensured that the network impact of the load that it controls has been mitigated, to ascertain design principles for a successor system.

5.2.1 Managing load using the RTS

The RTS was designed in the days of a vertically-integrated and nationalised ESI, which spanned generation to distribution. The design includes due consideration of the effects of load-switching at various voltage levels and on items of plant that also span generation to distribution. Unmitigated, at the start times of tariffs, networks would be subjected to instantaneous (within the timing accuracy of individual meters) increases in load.

The magnitude of these load-steps is around 9 kW per customer, if the water and space-heating load is switched at the same time, as for Economy 7 (E7) tariffs. Clearly, if there are many such customers in an area, this will cause significant step-changes in load to be seen by network equipment. In off-gas regions with predominantly electric-heating, these steps are significant at generation level. For a 300 kVA transformer supplying 17x E7 customers, the average load-step is around 18 kW in magnitude (6% of rated capacity) and load is 'picked-up' at an average rate of 9% of rated transformer capacity per-minute.

This appears relatively high and while it might be thought reasonable to spread the load over a greater period, by widening the range of time-offsets, the RTS allows for 7.5 minute resolution of switching-times. To reduce the pickup rate, utilities can make use of the facility for diversification of tariff-switching times that is built into the RTS. In practice, SSE switching times have not been resolved to finer resolution than 15 minutes (the vast majority are half-hourly), so it could be regarded that the range of time-offsets for a successor-system could be extended to ± 15 minutes without consequences.

5.2.2 Pickup of Electric Heating Load Using Teleswitches

In the early-days of the E7 and White Meter tariffs, take-up of the off-peak tariff created a peak in demand as the off-peak rate commenced. This created the need for plant to be held in spinning reserve and caused concern for the CEBG. To mitigate large step-changes in load, the RTS meter-specification BS7647:1993 ensures that each meter has an inbuilt ± 3 minute random offset time applied to their tariff-switching times (± 12 before RTS-synchronisation). The resolution is 7 steps, so for a large population of meters on the same

tariff, the load should be seen to increase in steps separated by 52 seconds, as depicted in Figure 2.

These seven-steps reduce voltage step-change and the associated flicker in two ways: by allowing time for tap-changing equipment to respond and by reducing the individual steps in load seen on the network. An analysis of voltage step-change (see Appendix 6) showed that this is effective in meeting the P28 requirement to maintain voltage step-change below 3% for fault-levels of less than 5 MVA / 7 kA at customer terminals (down to 3 MVA / 4 kA for single customers).

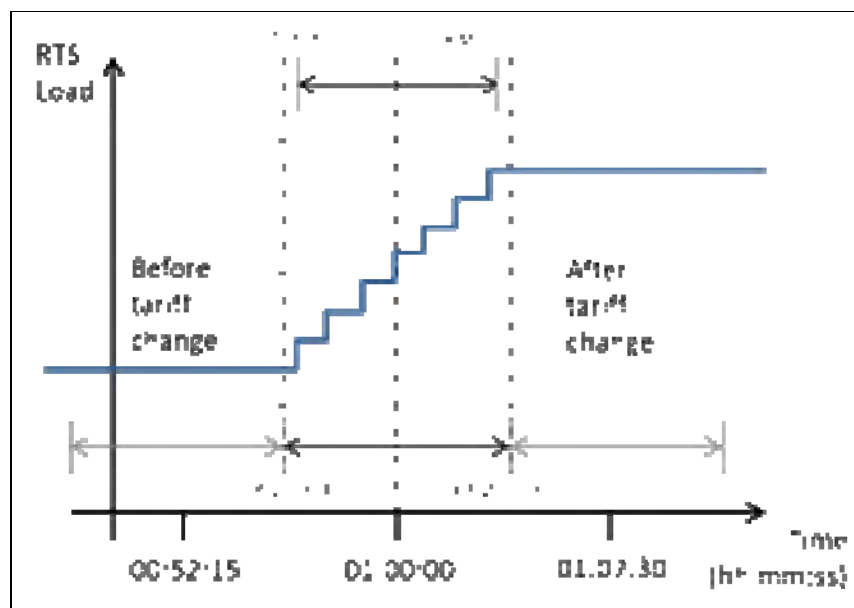


Figure 2: Theoretical RTS Load-Pickup

5.2.3 Choice of a profile for the onset of load

Any sort of profile could in theory be chosen for the pickup of electric heating load. BS7647 specifies random offsets that result in a stepped approximation to a linear rate of pickup, starting 3 minutes before the tariff switch-on. By using a large number of offsets, the approximation to linear load can be improved. However, it would not reduce the need to keep generation available in reserve, since this is driven by the magnitude of the whole load to be picked-up. Any advantage would be in the reduction of the maximum instantaneous load-step. This might have a small benefit in terms of generator frequency-stability and fuel consumption during the pickup, but is probably insignificant in comparison to daily energy costs.

There are several distributions that could be used to generate switch-on and switch-off profiles. For the RTS, as the numbers of group codes are limited it is necessary to switch large blocks of customers at the same time; the use of time-offsets reduces this. For every 1000 customers switched nominally at the same time, the $1000/7 = 143$ are switched per instant (or about 1.3 MVA at 9 kW each). The reason that these instantaneous steps have not been seen on Shetland (Figure 1) may be related to clock drift on the now quite old Teleswitches.

Any successor system, e.g. Smart Meter is likely to have better clock synchronisation, so the 7-step approach might well result in a number of discrete steps in SHEPD locations. Hence

it would seem sensible for any successor system e.g. the Smart Meter Load Control Variant to achieve a better approximation to a linear rate of pickup, i.e. a greater resolution for the time offsets.

By way of example, if offsets were applied with second-resolutions for half-hourly resolution of tariff switching-times, for 1000 customers switched nominally at the same time, one customer would be switched about every 2 seconds (9 kW).

For Shetland, this would reduce the need today to have 2 or more gen-sets spinning in advance of the current 8 MW demand-spike (related to the THTC tariff), to a phased introduction over a half-hour.

6 Conclusions

- C1 The RTS has been a mainstay in the management of load from customers with electric storage-heating and until recently has been the only system used to achieve this;
- C2 The RTS capability to change the programmed switching-times of customers has been used a number of times in SHEPD locations to manage peaks associated with storage-heating;
- C3 The RTS capability to immediately switch-off the charging of electric storage-heating customers is less well-known but has also been used a number of times in SHEPD locations;
- C4 Life extension of the existing BBC Long Wave radio transmission system is possible until an advanced-rollout of the Smart Metering system can be achieved in SHEPD locations;
- C5 Knowledge of the capability of the RTS, at least before SSEPD directed study into this area, has been scant. This means that awareness of the impact of the installed capacity of electric storage-heating customers is low and that the diversity that the RTS implements is not known;
- C6 By virtue of Conclusion C5 above, there are likely to be opportunities across SHEPD to optimise the configuration of the RTS to achieve significant reductions in peak load and to defer reinforcement (SSEPD is understood to be undertaking a trial in Inverary).
- C7 Teleswitches have one of two fall-back programmes of switching times. If these are ever activated, little diversity will be applied to storage-heating load with disastrous consequences for SHEPD.
- C8 There is a low-probability, high-impact risk to operation of SHEPD networks associated with the '7-day' reversion-to-fall-back programme setting that, to the extent of enquiries made for this project, appears active in at least a large proportion of SHEPD Teleswitches;
- C9 The cost of meeting the RTS switch-off and loss-of-primary control over switching programmes is estimated as some £718M across SHEPD.

- C10 The value of the Smart Metering rollout and optimum load-management approach is estimated as some £147M across SHEPD. Version 2 of the Smart Metering Equipment Technical Specification includes suitable mitigation for voltage step-change related to instantaneously-switched storage-heating load.
- C11 Practical use of the RTS facility to manage load has been limited by customer tariff-agreements. Pan-industry study could be undertaken into the likely and possible arrangements of tariffs for the Smart Metering System, such that limitations to the future load-management capability of the system are minimised. Ideally, THTC-type simultaneous tariff and load-switching would be implemented. A clarification of the relationship between tariffs and group-codes is necessary as the knowledge is scattered across SSE and it is difficult to obtain consistent information.
- C12 The approach of investigating one or more regions in detail and extrapolating for the others has been effective for developing a view of the scale and likely magnitude of the scenarios across SHEPD. However it has been found that there are significant differences between the regions, in terms of their networks and that the “one-size fits-all” extrapolation approach is not particularly accurate for the extrapolated regions. In particular, it was regarded as unwise to extrapolate for the 33 kV networks.

7 Recommendations

- R1 Life-extension of the existing radio transmission system for the RTS should be pursued so as to enable the replacement Smart Metering system to function as its successor. In concert, options for an advanced rollout in areas with high penetrations of electric storage-heating should be pursued.
- R2 Planned reinforcements in areas of with high penetrations of electric storage-heating should be reviewed (e.g. the example of Inverary referred-to in C6) to determine whether a re-allocation of the group-codes of those customers could defer the reinforcement. The development of a tool to calculate the optimum allocation for the minimum number of changes to customer’s Teleswitch group-codes should be considered (the CTCU is said to have a model that may be useful for development purposes).
- R3 If there is a need for scenario planning or for more accurate estimates of the impact for the extrapolated SHEPD regions, then further work should be undertaken.
- R4 It should be ascertained that the risk of a 7-day outage of the LW transmission system is so low that it is not necessary to undertake the significant programme of work required to change the RTS 7-day reversion setting to No-Revert.
- R5 For load-management purposes, negotiations with regard to the Smart Metering System load-control variant should include arrangements of tariffs to provide THTC-type control of load (that can be changed without prior notification) rather than set-times negotiated in advance of the need for load-management.

Appendix 1 Conversation Transcripts (RTS)

Response from Geoffrey Hensman regarding the roll-out and setting of RTS Teleswitch parameters, April 2012 (telecons and meetings with Dr S.D. Wilson EA Technology)

1. What was the rollout of RTS meters like? Was it dispersed according to customers choosing tariffs, or was it in blocks according to the replacement of E7/white meters?

Single rate mechanical meters had a certified life of 20yrs; multi-rate meters had a lower certified life. As they reached the end of their certified life mechanical meters would have been replaced with electronic ones, and radio telemeters in the case of new or replaced meters for multi-rate tariffs.

2. How were the time-randomisation settings chosen (± 3 min but ± 12 -15 min on first start-up)?

It was intended that a random number be generated at start-up of a Teleswitch and this would be converted to an offset. This offset was ± 12 minutes in the case of Teleswitches not receiving any programme instructions. Manufacturers did implement this feature differently; some did chose a random number and would be different each time the device started up; others had a fixed offset for each device, but they were randomised over the population during manufacture. If the Teleswitch did receive programme instructions the offset was reduced as the programme could be set to 7.5 minute blocks. This means that Teleswitches with the same group code will switch at slightly different times and not the exact time in the programmed memory. The CTCU has a model of all the Teleswitches under programme control and takes the offset into account in sending messages, but of course doesn't know exactly what times the individual Teleswitches will operate.

3. Any particular reason for the onset of load being chosen linearly (rather than say, the normal distribution)?

Don't quite understand the question.

The offset was intended to be spread evenly over the \pm offset period. This was to ensure that there wasn't a sudden loading on the network; it was spread over a number of minutes and could allow the network to adjust e.g. automatic tap changers with 90s or 120s delay times could respond and there shouldn't be too low volts due to the increase in load at say 00:30, the beginning of the E7 period.

4. What happens after a prolonged transmitter outage?

I'm still trying to find the full details. However, as far as I understand it, in the event of the transmitter being down for 24 hours or 7 days as specified by the "reversion setting" the Horstmann Teleswitch resets itself to 02:00 on 1 April. This is the same as when it loses power. This has quite severe implications as the fall back pattern on all devices will switch on with only the random start-up offset modifying the simultaneous switch-on.

Conversation Record – Dave Martin (Horstmann)

Dr S.D. Wilson, EA Technology, 22/3/12

Could meters receive signals under the condition of a loss of Droitwich?

Horstmann meters exceed the specification for signal reception, but it is not known by how much. To design and test the meters, Horstmann use a screened room equipped with a transmission antenna and a signal generator with a phase-shift input. This could be used to detect what the lowest strength of received signal could be (BS 7647 specifies a lower sensitivity of 100 micro volts per metre). When Horstmann were testing their meters, they did the lab work then drove around the regions (lowest signal strength in Falmouth apparently) to check function in low-signal strength and 'mush' areas between transmitters. Dave also noted that Droitwich was part of a national MoD emergency network (nuclear strike?) and that there was a backup to Droitwich at Evesham, equipped with a hydraulic aerial. His opinion was that it would be extremely unlikely that Droitwich would be switched-off (SDW note, not much point maintaining LW capability if everyone goes to DAB).

- ➔ Arqiva to be contacted regarding signal strengths and Droitwich backup (SDW couldn't find much info on the 'net')

Tele-switches and Meter Software / Comms

Dave asked if the meter types were known, the author looked at the first 65k codes and extracted the listed Horstmann meter types, sending these to DM. He commented that half were RTC (Real-Time Clock). These are manually programmed and equivalent to RTS-managed meters except that they do not receive programme updates.

- ➔ How have these come to be listed in the RTS spreadsheet? Are there less than 125k RTS meters in-use? Is the capability to reprogram these known about in the regions?

If the survey is done on Unst, an 'old' Windows 95 laptop may be required as not all the software was ported over to XP or later¹⁷. Also, there are no optical transducers remaining for the tele-switches with a 2-way comms port. They can be built-up at a cost by Horstmann if needed.

- ➔ It might save effort to implement a call-centre process to contact the 122 customers on Unst before surveying their meters, to determine whether teleswitches/meters are being used and what their types are, then the staff can go with the right equipment.

¹⁷ The SSEPD project manager, Bob Hopkins, has carried out the re-programming of an RTS meter in a test environment

**Record of a Conversation with Maurice Miller (Arqiva) regarding LW Data
Transmission**

Dr S.D. Wilson, EA Technology, 3/4/12

The Personal Opinion of Maurice Miller

The BBC currently owns the licences for audio and data transmission over 198 kHz. It is unlikely that the BBC would want the Scottish transmitters to be operated separately from Droitwich. Ofcom might be contacted with regard to issuance of a separate licence for data traffic but it was not thought that there would be a credible chance of success at least until the BBC had published its plans for LW transmission. Recent documents have not contained any such plans although the cost of operating the LW system is rather high relative to the numbers of listeners.

Life extension to 2016-8 was thought possible and likely, the route to achieving this being to broadcast at reduced power so that the choice for exiting LW transmission can be made rather than forced.

The best route for utilities to secure the operation of the system was thought to be to obtain a statement regarding the continuation of the system from the BBC and then to subsequently negotiate charges.

System Operation

Droitwich transmits using 2 parallel amplifiers. In the event of a failure the transmitting power would reduce instantaneously to $\frac{1}{4}$ and increase to $\frac{1}{2}$ following isolation of the faulty transmitter. Reduced power tests (3 dB, $\frac{1}{2}$ power) were recently carried out during the Test Match Special. No complaints were received and the test was limited to 5 days to prevent any possible reversion of RTS meters. At the same time certain ENA members tested data reception.

Operation at reduced power is possible because the system has plenty of spare 'link-bandwidth', (signal reaching North of Paris for example) which means that it is likely that only the odd meter with poor reception would suffer from a reduction in transmitter power (in the Droitwich reception region). Since setup in the 1980s the system has experienced almost no failures. Even with reduced-power operation, it was thought that service could be maintained to >95% of RTS meters, with no difference in reception in Scotland. While the system was used to disseminate information for flood warning sirens in the counties of Essex, Norfolk and Lincolnshire, it understood that this is no longer carried out.

Record of a conversation with Daniel Simpson, ENA

Dr S.D. Wilson, EA Technology, 16/01/12

ENA manages the system and the Central Teleswitch Control Unit (CTCU), to which DNOs connect and set switching patterns. These are then sent to the BBC and assembled into control codes at Crystal Palace. They are then broadcast via the Droitwich, Westerglen and Burghhead transmitters on LW 198 kHz. The Scottish transmitters are ½ the power of Droitwich. The existing transmission system is currently secured until 2013; further use is subject to the BBC's plan for LW transmission, which is currently to continue use of LW but not to invest in any new transmitters. The system is thought to be capable of broadcasting until at least 2016, possibly for a further 10 years using the available spares. There are 5 receiving stations that decode the signal and correspond with the CTCU so that commands can be re-transmitted if necessary.

The two Scottish transmitters have been re-engineered since build and do not have a shortage of spare parts. 10 valves are available for Droitwich, they are stored carefully on springs! To extend operation of the system, reduced-power transmission tests have been undertaken (July 2011 and planned 2012 as well).

The ENA sends quarterly reports to each user with their own area codes, switching and use-patterns. An archive of these is available back to 2006 (the ENA took-over management of the RTS from the Electricity Association in 2003). Simpson was not aware of an upwards or downwards trend in the number of instructions used, but apparently the number of blocks allocated to each user is quite generous, so headroom is available.

The costs of the system are allocated to users on the basis of the ratio of messaged requested. An email request for cost data has been made.

Appendix 2 Conversation Transcripts (Regional Use)

Record of conversation with Jeremy Duncan (JD), Lerwick Power Station (LPS)

Dr S.D. Wilson, EA Technology, 29/02/12

How often are the switching schedules revised?

As-and-when required.

Only 2 adjustments since the 1990s. Peaks tend to develop over time as new customers (homes, factories) are added. LPS is aware of the rate of load pickup that corresponds to tariff switch-on times. The THTC tariff is thought to be responsible for ~8 MW in winter. Expect ~10kW storage heating load, though not all will be on and charge is not thought to commence if not depleted.

Peaks and troughs

The mid-winter peak is significant especially if Sullom Voe Terminal is lost. Summer troughs are also a problem as LPS must run a minimum of 2 engine sets, take all output from the Burradale wind farm and >4MW from SVT (take or pay contract runs till 2014, also export-only connection). Load must be above 10/11 MW to avoid penalties. The trough generally occurs between 11pm-5am.

Emergency use of RTS

Has been used around 8 years ago when margins were tight, as have standby generating-sets.

Tariffs

Many tariffs in use on Shetland are historic; the THTC tariffs are primarily used for management of RTS-load through adjustment of on-times. LPS has no influence over the tariffs that are assigned, but can have the teleswitches in-situ reprogrammed onto different group codes. It is not known how the tariffs are assigned, but benefits could be realised if they could be intelligently chosen. JD has been asking for an holistic approach to this. A 3rd THTC tariff would be useful as the two existing THTC groups are causing peaks, due to the number of customers. An E10 tariff is also used on Shetland, but this is not delivered through RTS. The reallocation of THTC1 and THTC2 several years ago reduced the peak by some 4 MW (e.g. 1 gen-set). Limits are placed on the possible tariff time-allocations as some customers need to be contacted to advise, others may be fixed and some reallocations might affect comfort. Water-heating was thought to be the easiest to change without comfort impact.

Backup schedules

JD was unaware of this function in the meters. If the programmer software cannot obtain the backup schedules, then a test could be performed.

Record of a Conversation with Martin Lee (ML, SSEPD), regarding the use of RTS in Orkney

Dr S.D. Wilson, EATL, 27/3/12

Roles and Responsibilities

ML worked on the Orkney system 1986-2001 and managed the control of load using RTS 1994-2000. The aim was to flatten the load profile so that it could be met using the single submarine cable of 20 MW capacity plus supplementary diesel generating sets. ML's last experience of load-management was in 2000, during which the profile was reasonably flat. To his knowledge the RTS has not been managed since.

History

When the RTS became available around 1989, SSE began a programme to replace ~2000 mechanical time-switches on White Meter tariffs. These were assigned to two groups, GIDs 51 & 61. Diversity was introduced by ensuring that both were not normally on at the same time. The exception was at 04:00, when demand from the first group had decayed significantly.

A major problem arose around 1990 as a result of the first tele-switches not having the random offset function that is currently specified in BS7647. This created a step-change in voltage of 6-8% and tap-changers having to move through 4-5 taps at 10:00.

The tele-switches were changed for the new version with ± 3 minute offsets, which resulted in the same peak loads, but the step being spread over 6-7 minutes. Tap-changer settings were adjusted for a 30s delay rather than 2 minutes as reported to be used on the mainland. This resulted in no large steps in voltage and only a slight dimming of lights. Not all the earlier meters could be replaced. To ML's knowledge, around 20 remain.

When the THTC & Storage Heating Control (SHC) tariffs were introduced around 2002 these were implemented in 4 and 1 groups respectively to provide greater diversity in demand. Only a small number of SHC customers are connected (e.g. within industrial sites).

Load Profile, Wk. 6, 2000



Comments on Load Profile Wk. 6, 2000

Midnight – White Meters

01:00 Ramp-up of old mechanical time-switches (start-times spread-out over the years)
Old mechanical time-switches were deliberately not set accurately (to ramp load).
Clockwork backup mechanism on power-outage means that start-times spread-out.

03:00 THTC

04:00 Second White Meter + 2.8 MW

04:30 THTC + 1MW

06:00 THTC + 3 MW

07:00 Breakfast peak

09:00 THTC

The charts ML presented were used to alter times for the RTS, the aim being to ensure that the night-time peaks were of equal magnitude (flat). At that time, diesels were run overnight when the demand was greater than the 20 MW cable capacity. The scheduling to go with the chart would be 2x3.5 MW sets from 23:30 to ~11:00. Wind speed and rain have the most effect on demand. The charts were used to compare the day's load against the previous. From consideration of a number of days plus a view of the times and profiles of other loads, ML could gauge the effect of changing tariff-times. ML had subjectively split load up into 'wedges' to determine the RTS contribution.

The profile in 2000 was felt to be quite successful in reducing peak demand and the number of gen-sets being run. The two aims were: fill the day close to 20 MW, fill the night to reduce the peak and requirement for generators. Ideally, peak load would be ~25 MW overnight and 20 MW during the day.

Generation-data was missing from Elf (7.7-9.4 MW GTs) on some days.

Orkney Details

In 1998 a second sub-sea cable was installed, so that the situation above would only be relevant if one of the cables was out. ML handed management over to new staff in 2000, these did not consider RTS load-management to be as important. To ML's knowledge the cables have not had an outage, so there has been no need to call upon (n-1) arrangements, though if there had been then it would be a struggle to support the load. The cables are now 30 and 14 years of age, the latest managers have scant knowledge of the RTS.

In 2002, SSE supply issued new tariffs (e.g. E10 with 3-blocks of cheap-rate). For the most part, these were delivered nationally using electronic time-switches with either England (not on till 05:00) or Scotland times. Due to a shortage of electronic meters, some electronic meters were installed on Orkney with English times and some RTS meters were also used with English times.

On Orkney today there are:

- THTC: domestic and small commercial
- White Meters: various tariffs, some delivered through RTS
- SHC: some on RTS
- E10: some on RTS, most on electronic time-switches (HPs, storage heating and former E7 customers)

Recent loads seem to tie-up with data from 2000. There would be no immediate impact in switching-off RTS if the times were implemented in electronic meters, although it would be much harder to flexibly manage demand.

Emergency Events

The capability to send immediate command instructions had not been known. All load-management was achieved through programme updates, with a 2-hour delay. Kirkwall had its own RTS computer through which ML uploaded tariff-times. To-date, the Orkneys have not had an emergency such as to require the use of emergency switching.

Other Locations

The Western Isles were managed by George Mackenzie. Orkney, Shetland, Western Isles and the SSE Control Room were known to have RTS computers.

Appendix 3 Managing Peak Demand using RTS

The following document, dating from circa 2006, was obtained by SSEPD and describes the process used to manage peak-demands using the RTS.

PROPOSAL OF TELE-SWITCHING SCHEME MODIFICATIONS FOR SHETLAND NETWORK

A Tele-switching strategy is one where utility companies can directly control the duty cycle of domestic demand such as electrical storage heating. This control strategy has been generally used in the Shetland power system to adjust the demand portfolio, thus allowing the generation to be less stretched during high demand periods.

Both the demand peak value and the demand waveform have changed significantly since the commissioning of the Tele-switching scheme (back in 1993) according to the historical records. This is also the consequence of customers shifting from one group to the other over years. It was recognised that switching group-071 has only 15 customers left and is uneconomical to maintain anymore. In the meantime, the winter Peak Demand in Shetland reached 47.5 MW (Jan, 2005). This level of demand is a concern, considering the condition of the aging generator sets.

This report is to propose an approach to reduce the winter peak demand value by changing the current tele-switching patterns. It was noted that there might be a similar requirement for the summer period to optimise the system demand. However, as the majority of customers switch off their tele-switching facilities in the summer, it will be difficult to initiate novel control strategies.

System Maximum Demand

The system demand record for the 14th January 2005 was used as the starting point to tackle the situation.

As shown in the plot, the system demand has two peak values during the 24 hour period: the first occurs between 15:00-15:30 and reaches 47-47.5MW. The second peak occurs at 16:30-16:51 and reaches a peak of 40MW.

The two periods of sharp increments can be assumed to happen daily and clearly demonstrate the contribution of the tele-switching activity. To confirm this and allocate which customer group contributed to which profile, a detailed study was co-ordinated with Tele-switching Team as well as Customer Services within SHETL.

Dominating Customer Group

Tele-switching customers were divided into different switching groups distinguished by their group code. Each group has a certain switching agreement with the customers based on the tariff and the corresponding switching activity. For example, Domestic Economy customer Group-120 would be guaranteed 8 hours of storage heating per 24 hours. SHETL has some flexibility in deciding how to distribute the 8 hours to switch on the storage heating and meet the customer satisfactions.

From the information feedback, it could be concluded that Group-123 (containing 1221 customers) and Group-124(containing 2459 customers) had an obvious impact on the system demand portfolio. It is noted that each customer represents about 8kW demand.

From the existing switching scheme, it can be seen that Group-124 was switched on at 15:15 which contributed to the foundation of Peak Demand at 15:30 and Group-123 which was switched on at 16:45 which contributed to the Maximum Demand at 16:51.

Limitations in Change

The extent to which the change of switching patterns can be made is limited by the existing switching scheme, as customers have got used to the existing scheme and are happy with the heating schedule offered to them.. If an obvious change is to be applied, there will be two possible consequences: the customers will complain, or they will change their switching-group to bring the heating back on. Alternatively they will manually control their storage heating which will disable the tele-switching facility and dilute the overall tele-switching benefits to the Shetland power system.

Proposed Modifications

Based on the above mentioned information, the following modifications were proposed:

	TPRID with Customer Numbers	Group Code	Original Switching Pattern	Modified Switching Pattern	
				on	off
Modification-1	14143 THTC (2457)	124	14:00(on) -17:00 (off)	14:00 16:15*	15:30 17:45
Modification-2	14140 THTC (1221)	123	15:00(on)-18:00 (off)	12:00 15:30 18:15*	13:00 16:30 19:15
Modification-3	14125 Dom Econ (511)	110	16:00(on)-17:00(off)	15:00	16:00
Modification-4	14131 Dom Econ (563)	120	10:00(on)-13:00(off)	09:00	12:00

* Due to the limitation of the data used, the 16:00-17:30 was used in the spreadsheet

** Due to the limitation of the data used, the 18:30-19:30 was used in the spreadsheet

Amendment Verification

The proposed modifications will yield satisfactory result by reducing the peak demand 4-5 MW (plot 1).

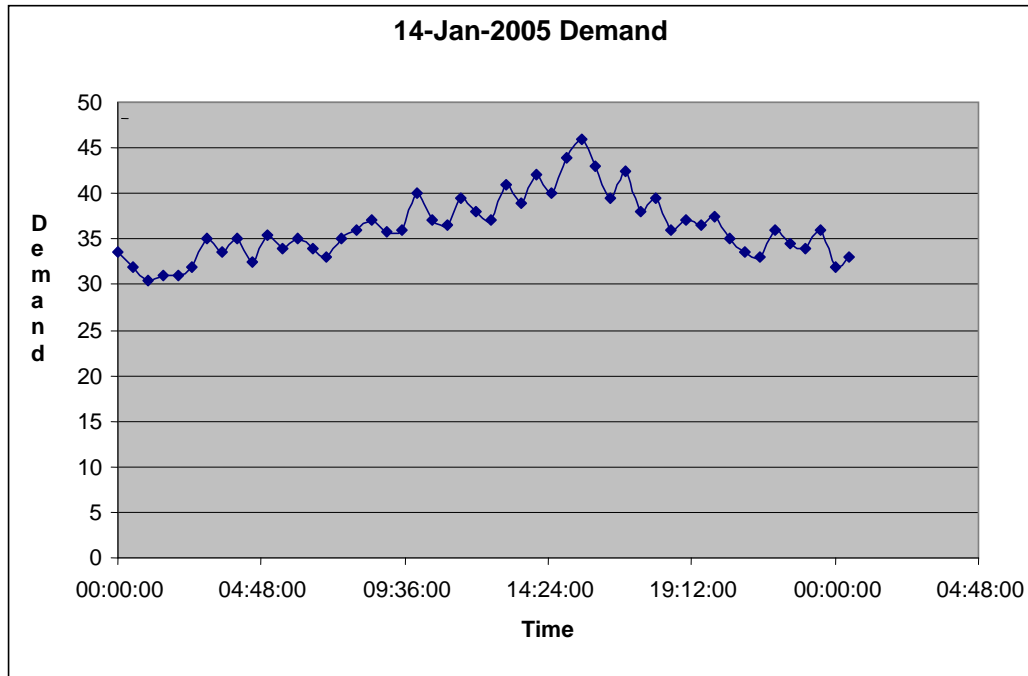
As the proposed modification was mainly based on a typical winter's day in 2005, further confirmation was sought from corresponding data originating from 2003 and 2004. The half-hour chart (plot 2,3) demonstrated similar satisfactory results as in 2005.

Assumptions

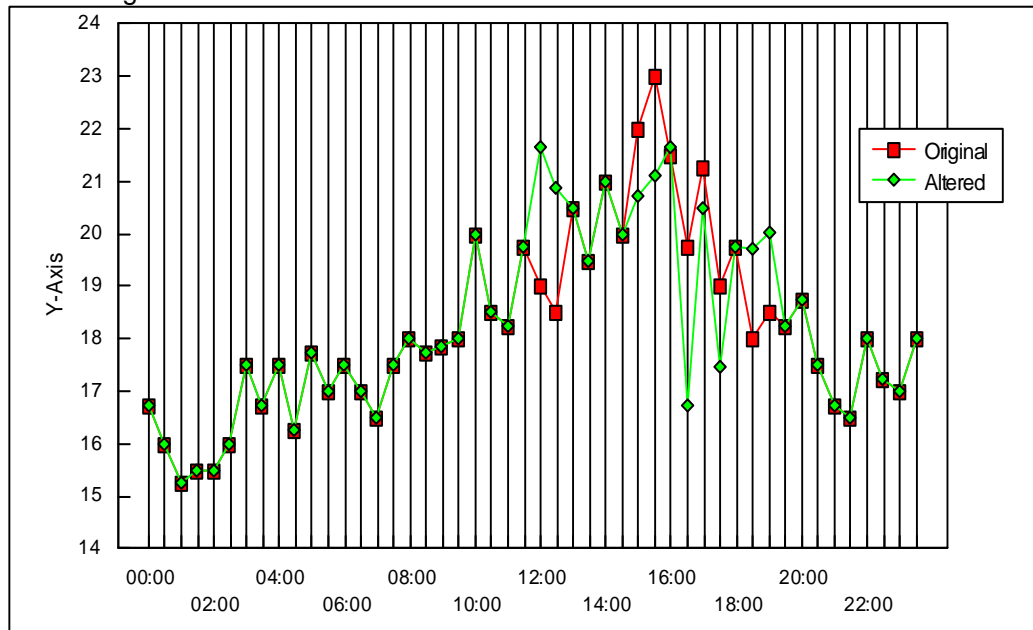
It should be aware that the spreadsheet tests were based on half-hour data and the following assumptions

- The data on the spreadsheet is based on a half-hourly sampling rate.
- The demand value in the chat is in MWH unit which was averaged every half an hour;
- The shifting of the switching time does not result in an overall change in the demand portfolio

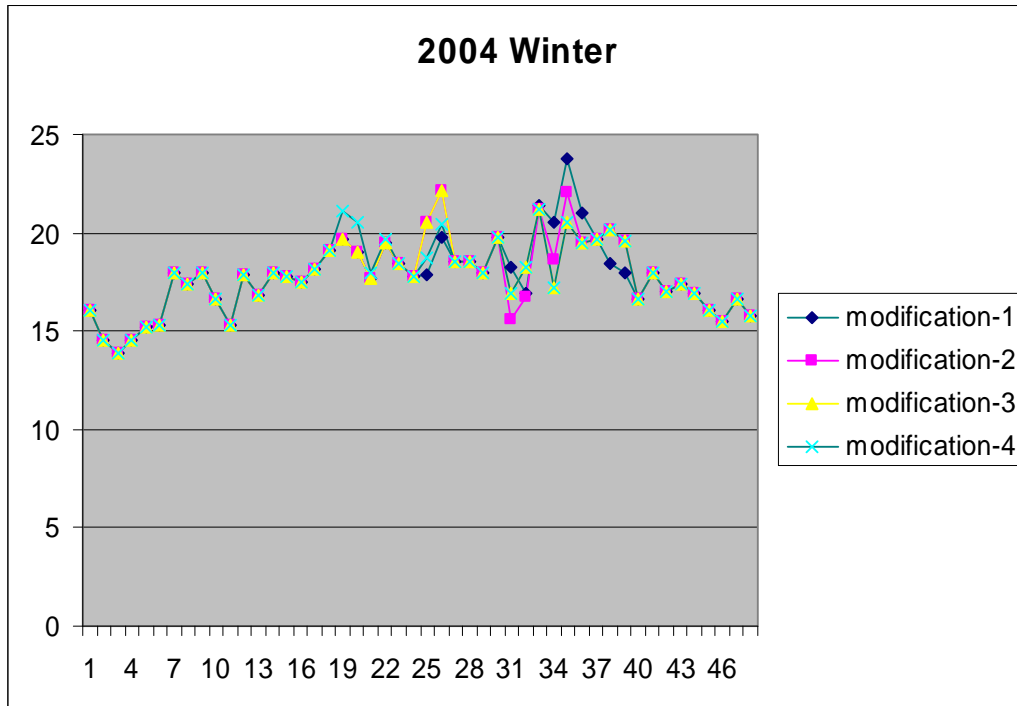
The theory is subject to the field test.



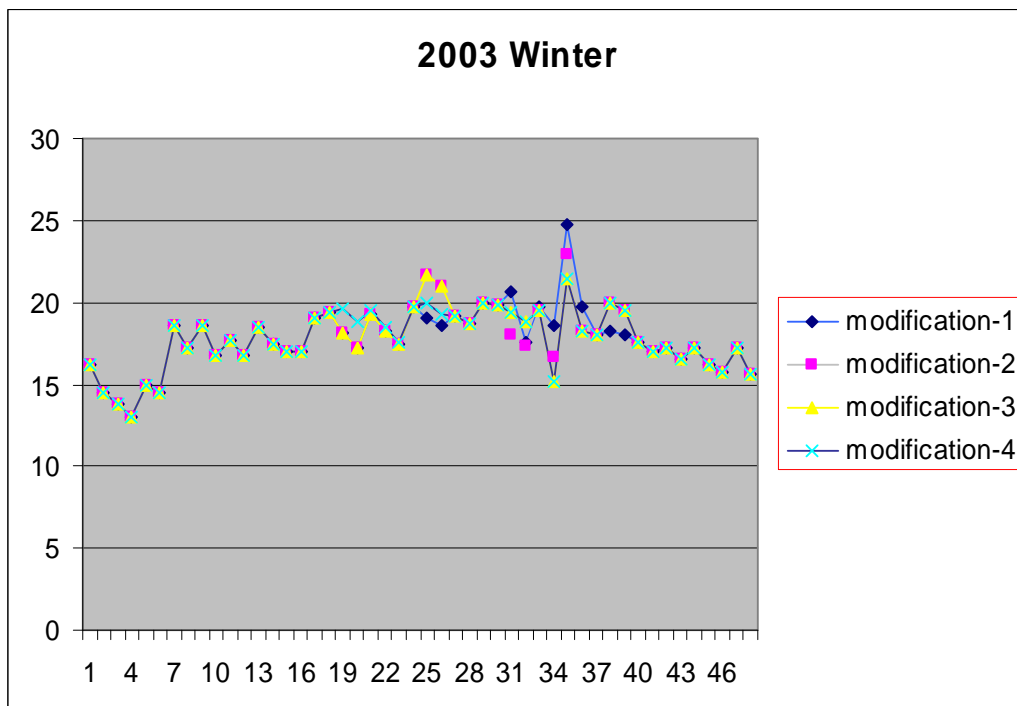
Plot 1 Original Demand Profile for 14-Jan-2005.



Plot 2: Proposed modifications to data of 2005



Plot 3: Verifying the switching pattern by using 2004 winter data



Plot 4: Verifying the switching pattern by using 2003 winter data

Appendix 4 RTS Applications Matrix

Application	Shetland	Orkney	Western Isles	Skye	Islay	Mainland areas
Peak load reduction (load shedding) A reduction in peak load for the purpose of reducing losses and the need for peak power of assets inc. generation and lines. This includes any deferral of capital that has been achieved by applying RTS solutions to networks.	Peak load is said to be reduced from 65-48MW in Summer and 30-22MW in Winter ¹⁸ with the use of the RTS devices. Expected that winter maximum demand is reduced from 40MW to around 20MW. ¹⁹	Peak load is reduced from roughly 43MW to 34.5MW with the use of the RTS ¹⁸ .	RTS is said to reduce peak load in winter from roughly 35-28.9MW ¹⁸ . It would cost £40 million for a submarine cable from Minch to Stornoway to cope with the added load from removing RTS. This is capital deferral. ¹⁸ On Uist, RTS is used to lower peak demand from roughly 10MW to lower than 9MW. ¹⁸	Deployment in all areas has been to realise the benefits of the RTS in mitigating peak loads		
Min load increasing (load boosting) An increase in the minimum load, for the purpose of increasing the amount of generation that can be tolerated or voltage support	The minimum load is said to be increased from 22-27MW in Summer and 6-10 MW in Winter ¹⁸ .	Not used.	Unknown.	Unknown		
Smooth load profile A similar use to peak load reduction, but primarily to reduce fast changes in demand that would occur with Economy 7 control of heating load, for instance. To reduce fuel usage for dispersed generators and plant wear. RTS is also used to prove a stepped onset of off-peak load.	"Demand smoothing" ¹⁸ is said to occur using the RTS on Shetland.	By smoothing the load profile using RTS, fuel generators can be used more efficiently, utilising less fuels and lowering maintenance costs ¹⁸ .	Unknown	Unknown		
Increase load diversity The use of different tariff switching-times across the spectrum of RTS-managed loads, to create diversity and lower demands in buildings or at substations.	Significant diversity has been applied to reduce peak loads even where the group codes being used are not the appropriate ones for each area.					

¹⁸ Scottish and Southern Energy; Radio Teleswitch Decommissioning; The Implications for Power Systems; March 2011

¹⁹ Teleswitching and demand smoothing; Alan K Robertson; Head of Purchasing, Scottish Hydro; Shore Road; Perth; 26 July 1993

Application	Shetland	Orkney	Western Isles	Skye	Islay	Mainland areas
Emergency flexibility and Security of Supply. The use of RTS 'Immediate' commands to switch load on or off (ignoring any pre-set switching pattern), to maintain security of supply in cases of dropped load, reduced network capacity or loss of generation.	Has been used around 8 years ago when supply margins were tight.	Not aware of the functionality.	Uist has used emergency commands twice in past 15 years at times of difficulty ¹⁸ . Submarine cable between Harris/Lewis. Should this cable fail there is not enough generation to support the island itself. ¹⁸ Uist – if submarine cable failed, generation of 9MW could possibly not be enough to secure the network ¹⁸ .	Not known to be used.		

Appendix 5 Shetland Impact Assessment

Quiescent Operating Conditions (RTS in Normal Operation)

SSE both on the supply and network operator side of the business has re-distributed the RTS load efficiently throughout the load profile of the Shetland Islands, driven by the necessity to maintain demand within generation margins. This re-distribution of demand has not only helped to constrain the maximum demand on the islands but also assisted with issues surrounding scheduling of generation at times of low overall load.

The whole island generation data supplied by SSE indicates that on the day of maximum island load in winter (14-Jan-2011) the overall island Simultaneous Maximum Demand (SMD) ranges from 29.2MW to a maximum of 45.8MW. This compares nicely with the summated substation PI data SMD which ranges from 29.7MW to a maximum of 47.7MW.

Calculation of the RTS load using customer numbers, allocation to group codes, group code switching times and estimated load profiles for space and water heating load calculate the Winter MD RTS of system load ranges from 7.9MW to 28.4MW.

The substation PI data was cross-referenced to primary substation transformer ratings. All transformers were operating within nameplate rating.

Cross referencing the system configuration with ERP P2-6 highlighted that most primary substations were non-compliant with this design document. However, SSEPD appear to have an exemption from applying P2/6 which from the calculations and empirical evidence appears to be being applied for Class of Supply B at Primary substation and 11kV distribution feeder level.

Abnormal Operating Conditions (RTS in Fall-back Mode)

If the RTS mode changes to Fall-back, in the scenario envisaged through withdrawal of the BBC command, control and communication service, the RTS load will switch from a highly disaggregated set of switching times and groups of customers to a situation where customers are allocated to one of two Fall-back Group Codes which switch load on for four discrete periods during the day with no overlap between periods.

Rather than the energy delivery to the RTS customers being smoothed out during the day it is concentrated into four short periods with a consequential and significant increase in the overall island maximum demand along with rapid increases and decreases in system load particularly at the beginning of these four periods.

The two Fall-back programmes are not symmetrical in the switching times, neither duration of switching nor overlap of space and water on/off periods allocated to each of the two codes. Dependent on the number of customers allocated to either Fall-back code, the load increase between the two extremes of imbalance of customer numbers allocated to either Fall-back code can be as much as an additional 47MW of load being added to the system with the normal island SMD being more than doubled to 100.7MW.

Generation Impact

The impact on the island's electrical generation system of the RTS entering either Fall-back mode scenario can only be described as disastrous, the principal issue being the woeful shortfall in generation capacity.

With the assumption that the Sullom Voe Terminal generation contract would remain unchanged, that Burradale Wind Farm and de-minimis wind farm output is excluded from consideration it is estimated that the island would require around an additional 72MVA of generation in addition to that currently deployed at Lerwick A and B generating stations.

A further generation consideration is that with RTS in normal operation RTS load is smoothed out over the island's 24-hour load profile. With RTS in Fall-back mode this is no longer the case and during periods when RTS load would have been an element of the load profile it will no longer be so. In its absence, during winter, and to a lesser extent during summer, the island will unfortunately achieve a new low in overall island minimum demand. This may present problems particularly with voltage control and issue which mandates that 40% of the islands demand is met by generation from Lerwick Power Station.

Addressing the island generation capacity would cause an increase in fault level across the electrical system affecting almost all aspects of plant particularly switchgear. Connection of any new generation capacity at Lerwick may cause fault level carrying capacity of existing assets to be exceeded.

Detailed analysis, as previously undertaken by Strathclyde University²⁰, would also need to be undertaken to ensure stability of the system under all envisaged operating and fault scenarios.

No consideration has been undertaken as to the coordination of investment in new generation capacity with respect to the replacement of time expired generation currently operating at Lerwick 'A' and 'B', nor to the research being undertaken under the NINES initiative.

33kV Transmission Network

Analysis of the loading of 33kV circuits shows that under worst case Fall-back conditions a number of circuits would need to be upgraded to ensure sufficient capacity under normal operating conditions. P2/6 considerations have been applied at this level.

No assessment has been made as to the capability of existing transmission network plant and circuits to increased fault levels as the result of increased generation capacity.

33/11kV Primary substations

Analysis of the loading of the 33/11kV primary substations shows that a number of primary substation transformers would require to be upgraded for capacity reasons.

11kV Distribution Network

Circuit rating data is unavailable and therefore an analysis of current circuit capacity under Fall-back operating conditions cannot be undertaken.

²⁰ The University of Strathclyde, Additional Wind Generation Connection to Shetland, not dated (circa 2006)

11kV/LV Distribution Transformers

Analysis of the available data shows that a considerable number of distribution transformers would require to be upgraded for capacity reasons.

Engineering Recommendation P2/6 – Security of Supply

Given that the existing arrangement at Lerwick A and B meets P2/6 recommendations for Class C Supply, in the case of additional generating capacity being commissioned, it is assumed that the P2/6 recommendations would continue to be adhered to through inclusion in any future design and operating arrangements.

In Fall-back mode every 33/11kV primary substation will be in the P2/6 Group Demand Class B with the exception of Gremista which remains in Class C (see above).

For the network in its current state, with the exception of Gremista A and B, the P2/6 recommendations seem to be applied at the generation and 33kV transmission level but not at Primary substation and 11kV distribution feeder level.

The SSE SHEPD LTDS 2012 alludes to an exemption from P2/6 being granted by Ofgem (PO-PS-037²¹). From how the network is designed it appears that this exemption applies at the Primary substation and 11kV circuit level.

Smart Meter

The Smart Meter programme has RTS 'equivalency' built in to the specification but it is unclear as to whether the separate 80A / 20A switching functionality will be maintained. If this is not the case the current disaggregated capability of separate switched space and water heating will be lost. However, since there will be disaggregated bi-directional communications to individual meters, this disaggregation of RTS group code communication and the assumed capability to directly command individual or dynamically alterable groups of meters will more than offset the segregated switching handicap.

Given the ability for the DNO to switch on and off the space and water heating loads for individual consumers as many times in a day as required by demand management and tariff energy delivery requirements, the Fall-back situation could alternatively be delivered by smoothing the energy delivery throughout the entire day, the resultant load curve on the island being flat. Theoretically the result would effectively be an equal maximum and minimum demand which if possible would mean a reduction in island MD from an existing level of 47.7MW to 36.9MW.

Such a situation would reduce capital costs, operating costs, enable the life extension of aged assets, alleviate generation scheduling and despatch problems and operational considerations such as voltage control and variance in output from wind generation.

Financial Modelling

The impact of enhancing each of the island's electrical generation, transmission network, and primary substation were calculated and or extrapolated from Shetland data and then converted to financial values using data supplied by SSE and/or DPCR5 allowed regulatory expenditures²².

²¹ SSEPD, Distribution Planning: Standards of Voltage and Security of Supply, PO-PS-037, Rev 1.02

²² Ofgem, Electricity Distribution Price Control Review Final Proposals – Allowed revenue – Cost assessment appendix, December 2009

Observations

RTS Step Change in Load

The group code switching is phased over seven 1-minute steps which are symmetric around the nominal switching time. Therefore 3 steps occur before the nominal switching time, a fourth at the switching time and three steps occur after.

Since tariff switching is only differentiated to a 15-minute window, the number of steps could be increased, theoretically to 31 which would increase or decrease the load in smaller amounts over the 15-minutes either side of the nominal switching time.

Co-ordination of switch on and switch off group codes could alleviate larger step change in load and therefore voltage fluctuations as well as increase the time period for the generators to adjust their output in line with demand increases and decreases.

Information Technology

To efficiently use any future Smart Meter technology for active network or demand side management will require an accurate asset database (point and linear) aligned with control room network topology along with appropriate telemetry from generation assets through the network down to individual customer connections at exit points with individual half-hour demand patterns.

With such technology and consistent data, the potential gains through efficient scheduling of generation, reduced island maximum demand, reduced duty cycle, deferred capital expenditure on network reinforcement, reduced operating expenditure would be considerable.

This technology would also allow SSE to automatically generate Load Management Notices and obligation under Schedule 8 of the DCuSA³.

Appendix 6 Pickup of Electric Heating Load using RTS

In the early-days of the E7 and White Meter tariffs, take-up of the off-peak tariff created a peak in demand as the off-peak rate commenced. This created the need for plant to be held in spinning reserve and caused concern for the CEGB.

To mitigate against large step-changes in load, the RTS meter-specification BS7647:1993 ensures that each meter has an inbuilt ± 3 minute random offset time applied to their tariff-switching times (± 12 before RTS-synchronisation). The resolution is 7 steps, so for a large population of meters on the same tariff, the load should be seen to increase in steps separated by 52 seconds, as depicted in Figure 2.

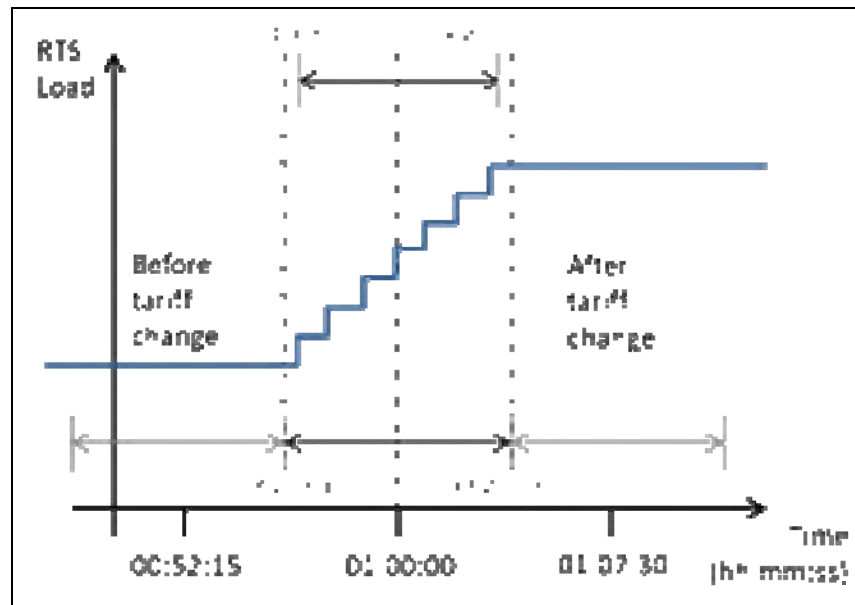


Figure 2: Theoretical RTS Load-Pickup

Taking for an example the Shetland Location, SSE's Lerwick Power Station uses generating-sets of around 4 MW to cater for daily variation in demand. The highest steps in load seen at the power station are today 8 MW in magnitude, accomplished over ± 3 minutes and with a maximum rate-of-change of load of 3 MW over a minute. This entails a substantial need for spinning reserve in the minutes before the tariff switch-on. The two largest load steps on the Shetland peak-day are depicted in Figure 1. The ± 3 minute period can easily be seen, though it is not possible to distinguish the 7-steps expected to be seen at the tariff change.

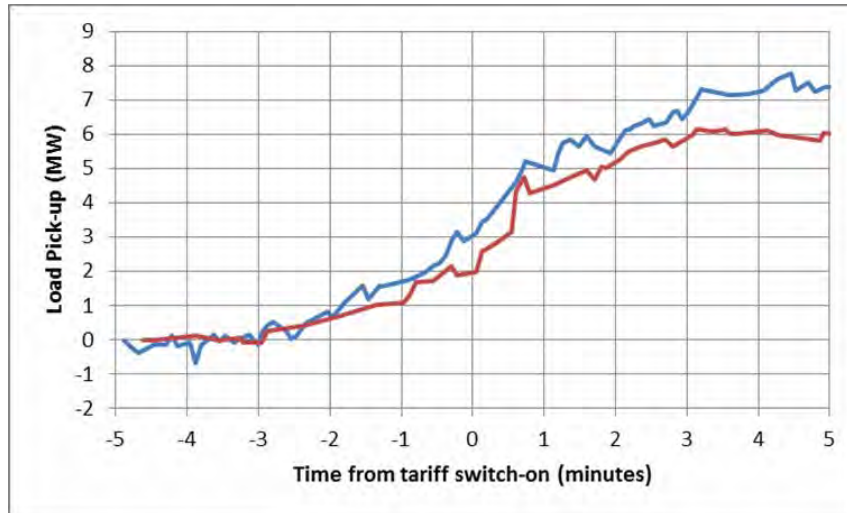


Figure 1: Shetland RTS Load-Pickup

Limitation of Instantaneous Load-Steps

The greater the magnitude of load that is switched instantaneously, the greater the corresponding voltage dip. Voltage-dips cause annoyance for users of the network; a voltage-dip of 3% is not exceeded in planning²³. The severity of the dip depends upon two factors: the source impedance and the magnitude of load switched in one step. The worst-case voltage dip is experienced at the lowest Fault-Level (FL). For example, at an LV FL of 2 MVA (3 kA), source impedance is $415 \text{ V} / 2 \text{ MVA} = 0.21 \Omega$. Assuming an R/X ratio of 1.0 at LV and allowing for the flow and return path, the phase-neutral resistance is also 0.21Ω . A 3% voltage step is $3\% \times 240\text{V} = 7.2\text{V}$ and is caused at a current of $7.2\text{V} / 0.21 \Omega = 35 \text{ A}$ and a real power of 8.3 kW.

Typical installed capacities for water- and storage-heating load are 3 kW and 6 kW respectively (these are “best-fit” values determined from the detailed analysis of Shetland RTS loads); therefore it is likely that the 3% step-change limit will be exceeded for RTS load under the conditions of the lowest FLs.

The step-change problem is exacerbated if more than one customer is switched-ON at once. The 7-step offset in the tele-switches reduces the likelihood of this occurring. For a 150 kVA transformer loaded to 50% of its rating, 75 kVA is available for load and thus 8 electric heating customers may be connected ($75 \text{ kVA} / (9 \text{ kVA})$), spread across 3 phases (2-3 per-phase). Assuming a perfect distribution of customers to steps, there is only 0.4 customers per-step, so the maximum step-change in load is 9 kVA.

Chance of switching causing a voltage drop in excess of the permissible 3%

Real distributions are allocated according to chance and there will be circumstances where more than one customer is switched at once, even for quite low numbers of customers. The likelihood increases as the size of transformer and the number of RTS-managed customers increases.

To represent this effect, the distribution of random numbers was investigated, finding that the standard-deviation between them is approximately 0.29 for numbers between 0 and 1. Using this result with a confidence level of 90% and the process described above,

²³ ENA, Engineering Recommendation P28, 1989

combinations of FLs and transformer-capacities can be checked to see whether they “pass” or “fail” a 3% voltage step-change, see **Table 3**, overleaf.

Table 3: Voltage Step-Change Characteristics (RTS Implementation, 7 Steps)

		Fault Level, (MVA)					
		2	5	10	12	15	20
Transformer rating, (kVA)	150	PASS	PASS	PASS	PASS	PASS	PASS
	300	FAIL	PASS	PASS	PASS	PASS	PASS
	500	FAIL	FAIL	PASS	PASS	PASS	PASS
	800	FAIL	FAIL	PASS	PASS	PASS	PASS
	1000	FAIL	FAIL	PASS	PASS	PASS	PASS

For single customers, a FL greater than 3 MVA (4 kA) is necessary. Clearly, the likelihood of more than one customer being switched at-once depends also upon the number of time-offsets available. By way of example, a quadrupling of the numbers of offsets available did not cause a change to Table 3 above.

Appendix 7 Fall-back Programmes

The following programmes were supplied by David Martin of Horstmann and apply to Horstmann K-series telemeters. The 'Non-Seasonal Stored Programme' is updated via the RTS when installed. The 'Fall-back Programme' is understood to be fixed at manufacture. While there are 6 K-series codes, there are only two Fall-back Programmes.

WinStation - Radio Telemeter JK --- OME DIRECTORYSOFTWARE - RELEASEDUTILITY CONFIGURATION FILESRT...

File Read Write Immediate Setup Help

Settings Display Tables

RTS Programme

Non-Seasonal Stored Programme

Weekday

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 03 : 30	03 : 30 04 : 00	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 03 : 30	03 : 30 04 : 00	-- : -- -- : --	23 : 30 00 : 30
Switch C	01 : 00 02 : 30	06 : 30 01 : 00	14 : 30 02 : 00	-- : -- -- : --
Switch D	04 : 00 04 : 00	11 : 00 02 : 00	-- : -- -- : --	20 : 00 02 : 00

Weekend

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 03 : 30	03 : 30 04 : 00	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 03 : 30	03 : 30 04 : 00	-- : -- -- : --	23 : 30 00 : 30
Switch C	01 : 00 02 : 30	06 : 30 01 : 00	14 : 30 02 : 00	-- : -- -- : --
Switch D	04 : 00 04 : 00	11 : 00 02 : 00	-- : -- -- : --	20 : 00 02 : 00

Fallback Programme

Weekday

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	03 : 00 03 : 30	14 : 30 02 : 00	-- : -- -- : --	-- : -- -- : --
Switch D	02 : 30 05 : 00	13 : 30 03 : 00	-- : -- -- : --	-- : -- -- : --

Weekend

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	03 : 00 03 : 30	14 : 30 02 : 00	-- : -- -- : --	-- : -- -- : --
Switch D	02 : 30 05 : 00	13 : 30 03 : 00	-- : -- -- : --	-- : -- -- : --

For Help, press F1

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File Read Write Immediate Setup Help

Settings Display Tables

RTS Programme

Seasonal Stored Programme

Season

1 January February March April May June July August September October November December

Day Type

1 Monday Tuesday Wednesday Thursday Friday Saturday Sunday

Programme

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00
Switch D	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00

Fallback Programme

Weekday

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00
Switch D	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00

Weekend

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00
Switch D	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00

For Help, press F1

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WinStation - Radio TelemeterJK --- OME DIRECTORY\SOFTWARE - RELEASED\UTILITY CONFIGURATION FILES\RT...											
File Read Write Immediate Setup Help											
RTS Programme	Settings	Non-Seasonal Stored Programme									
		Weekday									
		Block 0:- Start Duration		Block 1:- Start Duration		Block 2:- Start Duration		Block 3:- Start Duration			
		Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch C	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
		Switch D	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
		Weekend									
		Block 0:- Start Duration		Block 1:- Start Duration		Block 2:- Start Duration		Block 3:- Start Duration			
		Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch C	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
		Switch D	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
		Fallback Programme									
		Weekday									
		Block 0:- Start Duration		Block 1:- Start Duration		Block 2:- Start Duration		Block 3:- Start Duration			
		Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch C	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
		Switch D	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
		Weekend									
		Block 0:- Start Duration		Block 1:- Start Duration		Block 2:- Start Duration		Block 3:- Start Duration			
		Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30			
		Switch C	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
		Switch D	00 : 00 02 : 00	07 : 00 03 : 00	16 : 00 01 : 00	21 : 00 02 : 00					
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FileReadWriteImmediateSetupHelp

Settings

Display Tables

RTS Programme

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FileReadWriteImmediateSetupHelp

RTS Programme

Display Tables

Settings

Non-Seasonal Stored Programme

Weekday

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	03 : 00 03 : 30	14 : 30 02 : 00	-- : -- -- : --	-- : -- -- : --
Switch D	02 : 30 05 : 00	13 : 30 03 : 00	-- : -- -- : --	-- : -- -- : --

Weekend

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	03 : 00 03 : 30	14 : 30 02 : 00	-- : -- -- : --	-- : -- -- : --
Switch D	02 : 30 05 : 00	13 : 30 03 : 00	-- : -- -- : --	-- : -- -- : --

Fallback Programme

Weekday

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	03 : 00 03 : 30	14 : 30 02 : 00	-- : -- -- : --	-- : -- -- : --
Switch D	02 : 30 05 : 00	13 : 30 03 : 00	-- : -- -- : --	-- : -- -- : --

Weekend

	Block 0:- Start Duration	Block 1:- Start Duration	Block 2:- Start Duration	Block 3:- Start Duration
Switch A	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch B	00 : 00 07 : 30	-- : -- -- : --	-- : -- -- : --	23 : 30 00 : 30
Switch C	03 : 00 03 : 30	14 : 30 02 : 00	-- : -- -- : --	-- : -- -- : --
Switch D	02 : 30 05 : 00	13 : 30 03 : 00	-- : -- -- : --	-- : -- -- : --

For Help, press F1

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FileReadWriteImmediateSetupHelp

Settings

Display Tables

RTS Programme

Non-Seasonal Stored Programme

Weekday

Block 0:- Start | DurationBlock 1:- Start | DurationBlock 2:- Start | DurationBlock 3:- Start | Duration

Switch A00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch B00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch C03 : 0003 : 3014 : 3002 : 00-- : -- -- : ---- : -- -- : --

Switch D02 : 3005 : 0013 : 3003 : 00-- : -- -- : ---- : -- -- : --

Weekend

Block 0:- Start | DurationBlock 1:- Start | DurationBlock 2:- Start | DurationBlock 3:- Start | Duration

Switch A00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch B00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch C03 : 0003 : 3014 : 3002 : 00-- : -- -- : ---- : -- -- : --

Switch D02 : 3005 : 0013 : 3003 : 00-- : -- -- : ---- : -- -- : --

Fallback Programme

Weekday

Block 0:- Start | DurationBlock 1:- Start | DurationBlock 2:- Start | DurationBlock 3:- Start | Duration

Switch A00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch B00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch C03 : 0003 : 3014 : 3002 : 00-- : -- -- : ---- : -- -- : --

Switch D02 : 3005 : 0013 : 3003 : 00-- : -- -- : ---- : -- -- : --

Weekend

Block 0:- Start | DurationBlock 1:- Start | DurationBlock 2:- Start | DurationBlock 3:- Start | Duration

Switch A00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch B00 : 0007 : 30-- : -- -- : ---- : -- -- : --23 : 3000 : 30

Switch C03 : 0003 : 3014 : 3002 : 00-- : -- -- : ---- : -- -- : --

Switch D02 : 3005 : 0013 : 3003 : 00-- : -- -- : ---- : -- -- : --

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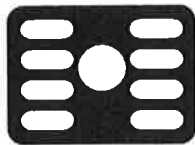
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Appendix 8 Telemeter Reversion Settings

Horstmann were able to identify the following details for the settings of K-series Telemeters ordered by SSE (supplied by David Martin, 18/04/2012).

	Meter Serial No.	Programming Sheet (internal)	Group Code	Delay to Fall-back
1	NU0770012214	42609	016	7 Days
2	NU0770112214	42610	026	7 Days
3	NU0770212214	42611	036	7 Days
4	NU0770312214	42612	046	7 Days
5	NU0770412214	42940	028	7 Days
6	NU0770512214	42764	094	7 Days
7	NU0770612214	42765	096	7 Days
8	NU0770712214	42766	097	7 Days
9	NU0770812214	42767	098	7 Days
10	NU0770912214	42768	095	7 Days
11	NU0770013214	42954	121	7 Days
12	NU0770029914	42672	036	7 Days

Appendix 9 Horstmann Tariff Programming Unit



HORSTMANN

TARIFF PROGRAMMING UNIT (T.P.U.)

OPERATION GUIDE

V3 05/07/02

Horstmann Controls Ltd
South Bristol Business Park
Bristol BS4 1UP
t. 0117 9788 700
f. 0117 9788 701

Part No. 80805/000

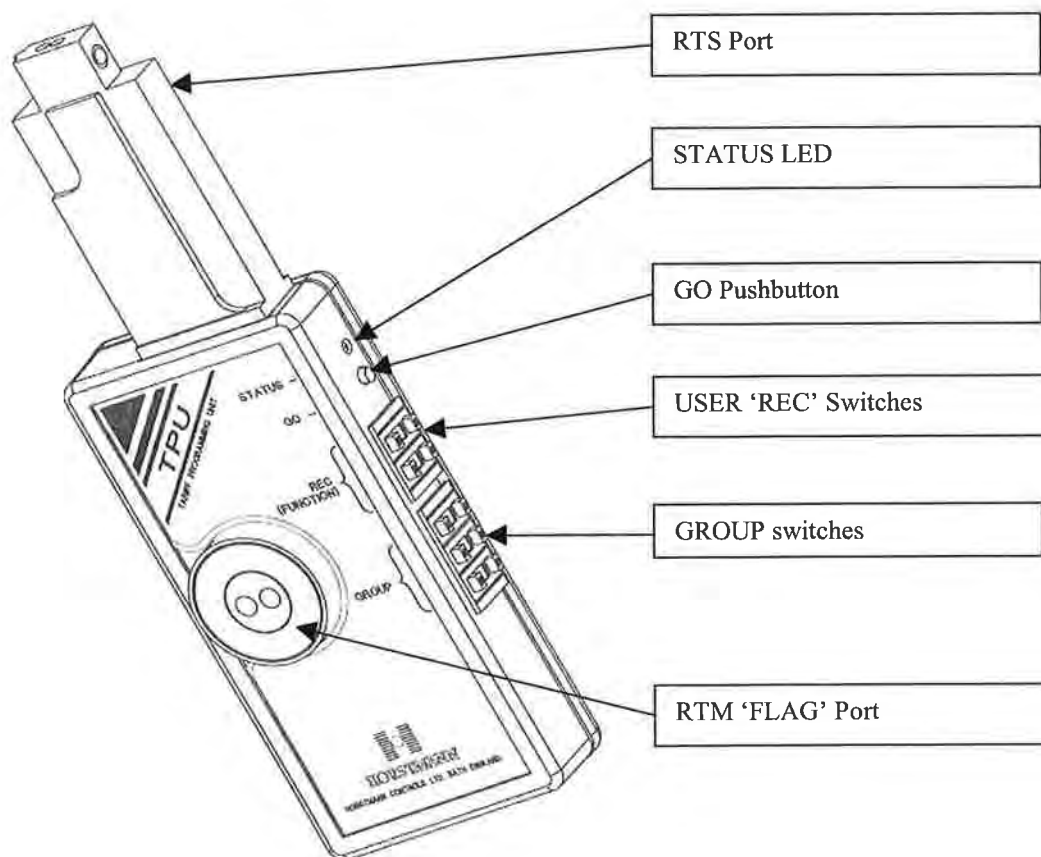
TARIFF PROGRAMMING UNIT

Operation Guide.

1) DEFINITION OF CONTROLS	3
2) MENU OF OPERATIONS.	4
3) STATUS LED , TEST RESULTS.	8
4) POWER ON/OFF , BATTERY TYPE.....	8
5) USER CODE QUICK REFERENCE	9
6) RANDOM OFFSET CODE TABLES	10

1) Definition of controls.

- 1.1) USER code thumbwheel switches:
A pair of thumbwheel switches giving a numerical input range of 00 to 99.
- 1.2) GROUP code thumbwheel switches:
A trio of thumbwheel switches giving a numerical input range of 000 to 999.
- 1.3) GO pushbutton:
A momentary pushbutton to activate the operation currently selected
On the USER and GROUP thumbwheels.
- 1.4) STATUS lamp:
A bicolour LED red/green to show the progress and results of the current
operation.



2) Menu of Operations.

2.1) USER Code Programming

- [1] Dial up the required USER code on the USER code thumbwheels, noting that the only valid entries are in the range 00 to 15 inclusive.
- [2] If a GROUP code is required to be programmed at the same time, dial up a valid group code in the range 000 to 255, else set the GROUP to any number in 256-999 range.
- [3] Operate the GO pushbutton.

2.2) GROUP code programming ONLY:

- [1] Dial in the required GROUP code in range 000 - 255
- [2] Dial in USER code 20.
- [3] Operate the GO pushbutton.

2.3) Random Offset.

- [1] Dial in a special-function **USER code of 87**,
- [2] Dial in random offset code on GROUP code, (see lookup tables for codes)
- [3] Operate GO pushbutton.

2.4)

Testing Contacts

2.4.1) General Notes for Testing Contacts

i) The contact test functions (USER codes of 80/81/82/83/84) drive the selected contacts for test purposes.

Each contact selection option ('A', 'B', 'C', 'D' or 'ALL') has 3 further sub options.

The sub-options are:

- | | | |
|-------|----------------------|-----------------------------|
| (i) | contact cycle ON OFF | with all other contacts OFF |
| (ii) | force contact ON | with all other contacts OFF |
| (iii) | force contact OFF | with all other contacts ON |

Whilst under 'contact cycle', the selected contact is set ON for 20 seconds then OFF for 20 seconds, this is repeated 4 times. This gives total test duration of approximately 3 minutes. Whilst under 'force contact', the selected option is held for a test time of approximately 3 minutes.

The sub-option is selected by the setting on the GROUP rotary switches, thus:-

GROUP = 900 selects 'force contact' ON

GROUP = 800 selects 'force contact' OFF

GROUP = 700 selects 'cycle contact'.

ii) Whilst under "cycle contacts" the test procedure sets the selected contacts 'ON' first. If the contact was already ON at the beginning of the test, then it will remain ON for the first 20 seconds of the test. Therefore, it might be erroneously assumed that the unit is not responding.

iii) No checking is done on the availability of the selected contact for any test. If you choose a contact for testing that is not physically fitted in the Teleswitch, the T.P.U. and the Teleswitch will perform the entire test sequence as if the contact was fitted. As an outside observer nothing will appear to happen for the 3 minutes of test duration.

iv) For teleswitch type **RTS2E**, when the test is complete, or if the T.P.U is removed from the teleswitch midway through the test, the teleswitch will automatically restore all contacts to the state they were in before the start of any tests. This may take a couple of minutes to occur however.

For teleswitch types **RTS2D** however, the contacts will remain in the state the T.P.U. left them at the end of the test. If a 'cycle contacts' test continues to a successful completion, then the teleswitch remains with all contacts OFF. A 'force contacts' test leaves the contacts in the selected forced condition. If the test on a **RTS2D** is interrupted then the contacts are left in an indeterminate state. The contacts will remain as the test left them until the next programmed ON or OFF time. To overcome this problem, it is recommended that the power to a **RTS2D** teleswitch be removed for 30 seconds after all contact tests are complete. Upon power being reapplied the teleswitch will return the contacts to programmed status after it has performed its 3-minute initialisation routines.

GROUP switch settings for Testing Contacts

For 'contact cycle' option, set GROUP to 700.

For 'force contact' ON option, set GROUP to 900.

For 'force contact' OFF option, set GROUP to 800.

- 2.4.2) Test Contacts set 'A'.**
[1] Dial in special-function **USER code of 80**,
[2] Dial in the sub option on the GROUP switches
[3] Operate the GO pushbutton.
- 2.4.3) Test Contacts set 'B'.**
[1] Dial in special-function **USER code of 81**,
[2] Dial in the sub option on the GROUP switches
[3] Operate the GO pushbutton.
- 2.4.4) Test Contacts set 'C'.**
[1] Dial in special-function **USER code of 82**,
[2] Dial in the sub option on the GROUP switches
[3] Operate the GO pushbutton.
- 2.4.5) Test Contacts set 'D'.**
[1] Dial in special-function **USER code of 83**,
[2] Dial in the sub option on the GROUP switches
[3] Operate the GO pushbutton.
- 2.4.6) Test ALL Contacts'.**
[1] Dial in special-function **USER code of 84**,
[2] Dial in the sub option on the GROUP switches
[3] Operate the GO pushbutton.

2.5) Radio Reception

- 2.5.1) Read 24 hour Radio Reception Status.**
This shows on the STATUS lamp the condition of the radio reception based on the previous 24-hour reception data.
Red lamp for bad (less than 90%) green for healthy.
[1] Dial in special-function **USER code of 85**,
[2] GROUP code setting is irrelevant for this test,
[3] Operate the GO pushbutton.
- 2.5.2) Read 1 hour Radio Reception Status.**
This shows on the STATUS lamp the condition of the radio reception based on the previous 1-hour reception data.
Red lamp for bad (less than 90%) green for healthy.
[1] Dial in special-function **USER code of 86**,
[2] GROUP code setting is irrelevant for this test,
[3] Operate the GO pushbutton.

2.6) Miscellaneous

2.6.1) Self-Test - Low Battery Indication.

This will flash the RED and GREEN LED's for 10 seconds whilst monitoring the battery voltage. If the battery voltage falls below a minimum threshold (6.7V) the test will immediately terminate and show FAIL. The GO pushbutton MUST be held ON for the entire duration of this self-test. If the battery level is exceptionally low, there may be insufficient power to complete the self test function, this could cause many unpredictable results – If the test does not result in "Success" (Green) on the status led, it should be presumed the test is "Fail" even if the test could not complete to indicate the "Fail" (Red) state.

- [1] Dial in special-function **USER code of 90**,
- [2] GROUP code setting is irrelevant for this test,
- [3] operate the GO pushbutton for the entire test time

2.6.2) Transfer USER and GROUP codes from RTM2 to GATEWAY

- [1] Dial in special-function **USER code of 95**
- [2] Connect the round FLAG optical port to the RTM
- [3] Operate the GO pushbutton to read the RTM
- [4] Wait for the status LED to pulse green (1/2 second on, 1/2 second off)
- [5] Then, connect the T.P.U. RTS probe to GATEWAY to transfer USER/GROUP codes
(TPU status LED will continue to flash green for up to 2 minutes, until Communication with a RTS3 type GATEWAY is established).

2.6.3) Put RTM2 into 'Test' mode.

- [1] Dial in special-function **USER code of 96**
- [2] Connect the round FLAG optical port to the RTM
- [3] GROUP code setting is irrelevant for this test,
- [4] Operate the GO pushbutton to set the RTM into Test Mode

2.6.4) Return RTM2 into 'Normal' mode.

- [1] Dial in special-function **USER code of 97**
- [2] Connect the round FLAG optical port to the RTM
- [3] GROUP code setting is irrelevant for this test,
- [4] Operate the GO pushbutton to reset the RTM into Normal Mode.

- 2.6.5) Unimplemented special functions (USER Codes 88,89,91,92,93,94,9899) will perform a communications session with a RTS/RTM but no operation is performed. These functions will always end with FAILED status.

3) Status LED, Test Results.

- 3.0) During initial few seconds of communication with an RTS or RTM the T.P.U. status LED will flash GREEN while the T.P.U. is transmitting to the RTS/RTM and flash RED while receiving data from the RTS/RTM. (This feature is to aid diagnosis of problems when consistent test results are FAILED. If there is no red LED activity immediately after a burst of green LED activity the RTS/RTM is not responding to the T.P.U).
- 3.2) Test result is SUCCESS:
If the GREEN status LED illuminates for a 5 second continuous period.
- 3.3) Test result is FAILED:
If the RED status LED pulses ON / OFF for a 5 second period.
- 3.4) Test result is UNRECOGNISED option(s) on USER/GROUP switches:
If the RED status LED illuminates for a 5 second continuous period.
- 3.5) Operation is still IN PROGRESS while GREEN status LED flashes.
Short pulses are produced during any operation that take significant time to complete, such as "contacts testing" and "GATEWAY transfers" where the operator may erroneously suspect the T.P.U. is inactive.

4) Power on/off, Battery types.

- 4.0) Power ON
By operating the GO pushbutton, the T.P.U. will automatically power itself up.
- 4.1) Power OFF
The unit will automatically power off at the end of each test, after the status LED has finished signalling SUCCESS, FAILED or UNRECOGNISED.
- 4.2) Battery types.
The T.P.U. is designed for use with a nominal 9 Volt PP3 style battery. Any type of battery is acceptable (standard, alkaline, rechargeable NICAD etc). The terminal voltage is not relevant provided at least 7.0 volts is available. Reverse battery polarity protection is built into the T.P.U. to prevent damage should this occur.
- 4.3) Low / Flat Battery problems.
The self-test option, (USER Code 90,) is provided to test the Battery State. Note, however, that there is no specific result to normal function operation to show that the battery is low. Successful operation can still be achieved with an almost flat battery. But if operation appears abnormal, or a function consistently results in "Fail" the "self test" should be performed to establish Battery State before investigating any other causes of error.

5) USER Code Quick Reference

USER Code	Operation
00 to 15 inclusive	= Programmes this USER Code into a RTS
20	Programmes a GROUP Code into a RTS
80	Test RTS contact A
81	Test RTS contact B
82	Test RTS contact C
83	Test RTS contact D
84	Test all RTS contacts
85	Test RTS 24 hour radio reception
86	Test RTS 1 hour radio reception
87	Programmes a Random offset into a RTS
90	Battery Test
95	Transfer USER and GROUP codes to a Gateway
96	Puts RTM2 into test mode
97	Puts RTM2 into normal mode

6) Random Offset Code Tables

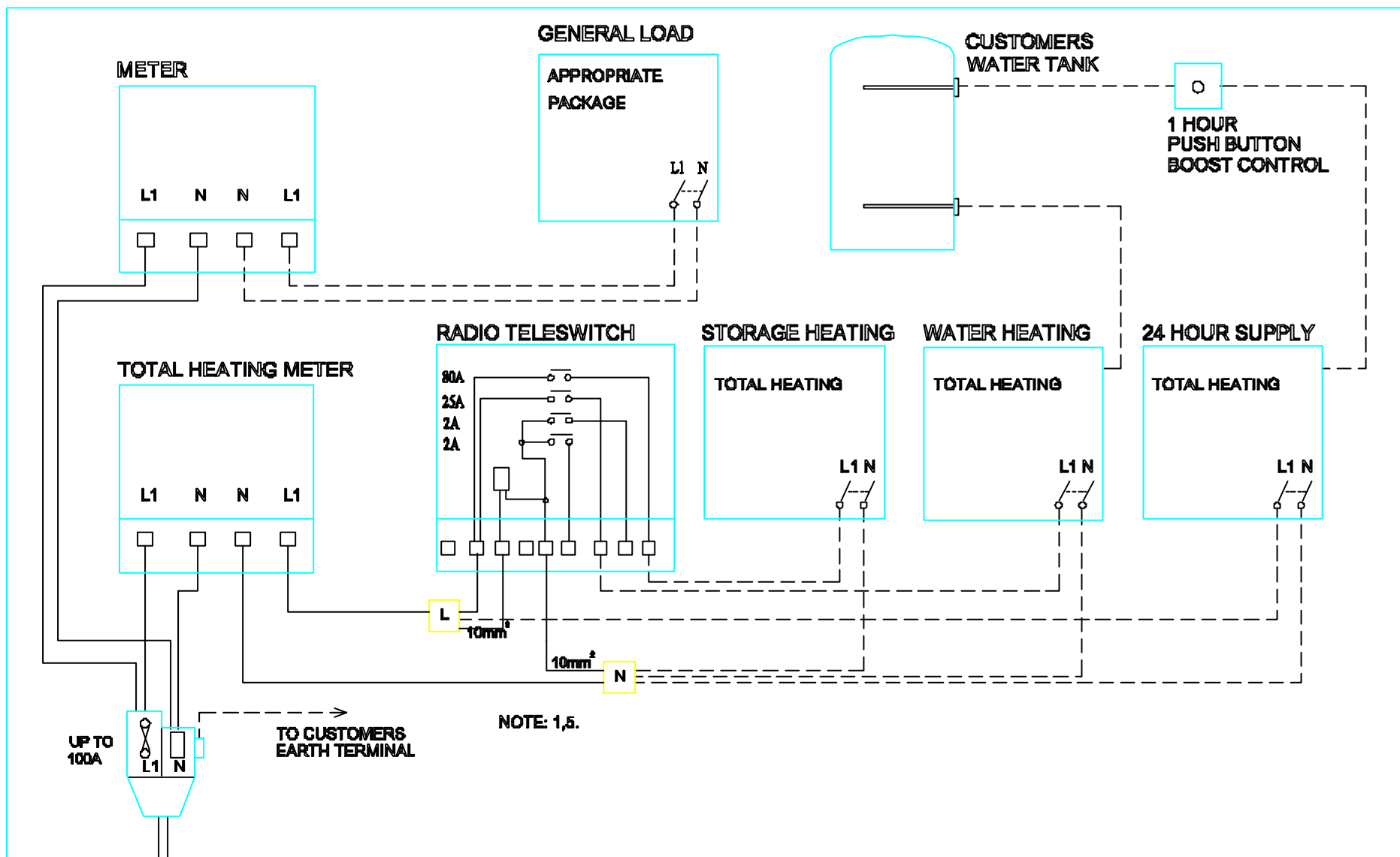
RTS2E Random Offset Codes

OFFSET (Minutes)	GROUP CODE	OFFSET CODE	
0.0	000		
0.5	001	-0.5	063
1.0	002	-1.0	062
1.5	003	-1.5	061
2.0	004	-2.0	060
2.5	005	-2.5	059
3.0	006	-3.0	058
3.5	007	-3.5	057
4.0	008	-4.0	056
4.5	009	-4.5	055
5.0	010	-5.0	054
5.5	011	-5.5	053
6.0	012	-6.0	052
6.5	013	-6.5	051
7.0	014	-7.0	050
7.5	015	-7.5	049
8.0	016	-8.0	048
8.5	017	-8.5	047
9.0	018	-9.0	046
9.5	019	-9.5	045
10.0	020	-10.0	044
10.5	021	-10.5	043
11.0	022	-11.0	042
11.5	023	-11.5	041
12.0	024	-12.0	040
12.5	025	-12.5	039
13.0	026	-13.0	038
13.5	027	-13.5	037

RTS 2D Random Offset Codes

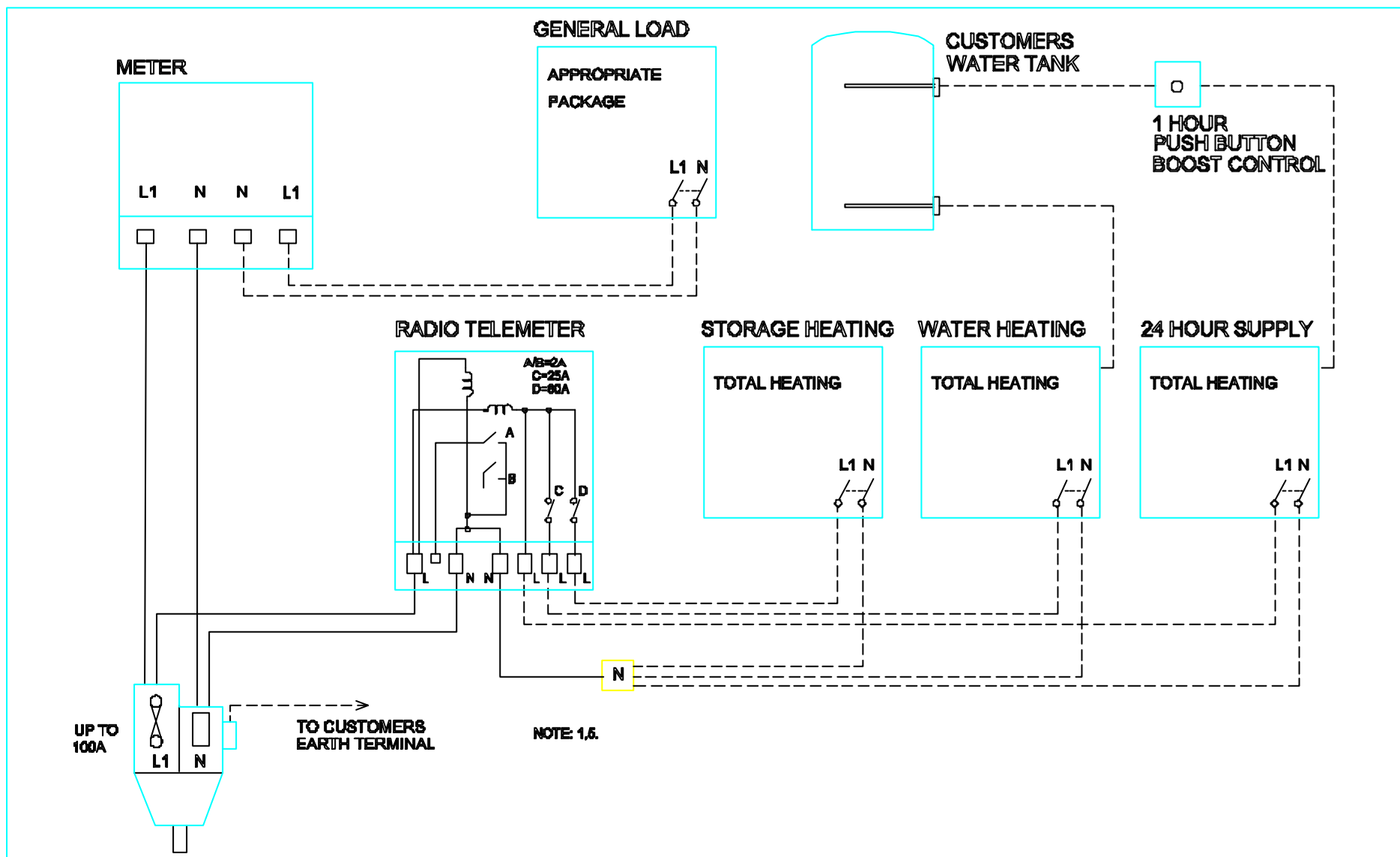
OFFSET (minutes)	GROUP CODE	OFFSET CODE	
0	000		
2	021	-2	149
4	042	-4	170
6	063	-6	191
8	084	-8	212
10.5	105	-10.5	233
12.5	126	-12.5	254

Appendix 10 Connection Details for THTC Tariff



SHEET 06

Rev.	04	Date June 2003	Date	JUL 92	Title METER ARRANGEMENT DIAGRAM FOR SINGLE PHASE TOTAL HEATING WITH TOTAL CONTROL PACKAGE USING RADIO TELESWITCH		SSE Power Distribution		Power Systems PERTH	
	05	Date 04/04/2005	Drawn	I.D.H.						
		Approved D.H.R.	Checked	D.H.R.	Project	Drg.No. 701/0600/0024	Sht.No. 06	Rev. 05		
		New Logo added and made.	Approved	D.H.R.						
		Approved D.H.R.	Scale							



SHEET 13

Rev.	Date	June 2003	Date	JUL 92
04	Modifications.	Approved D. Smith June 2004	Drawn	I.D.H.
Rev.	Date	04/04/2005	Checked	D.H.R.
05	New Logo added and made O.E.S. (S)	Approved D. Smith (2005)	Approved	D.H.R.
			Scale	

Title		METER ARRANGEMENT DIAGRAM FOR SINGLE PHASE TOTAL HEATING WITH TOTAL CONTROL PACKAGE USING RADIO TELEMETER	
Project		Drg.No.	701/0600/0024

SSE Power Distribution

SHLNo.	Rev.	Power Systems PERTH
13	05	

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2003

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Communicating
the Message

