SVG109/01

Meeting name	Supplier Volume Allocation Group (SVG)
Date of meeting	2 March 2010
Paper title	Change Proposal Progression
Purpose of paper	For Decision
Synopsis	This paper provides: • CP1315, CP1322, CP1323 and CP1324 for decision; and • an update on the status of all Open Change Proposals (CPs) and Draft Change Proposals (DCPs).

1 Introduction

1.1 This paper presents CP1315, CP1322, CP1323 and CP1324 for you to consider and agree on their progression.

1.2 We presented CP1315 to you previously at your SVG106 meeting on 1 December 2009 (Please refer to Attachment A for our detailed assessment report for CP1315). At the meeting you decided to defer your decision pending the outcome of an assessment of CP1315 by the MRA Service Company (MRASCo). We will provide you with an update of this assessment and invite you to approve CP1315.

1.3 CP1322, CP1323 and CP1324 were assessed by us and have undergone Impact Assessment (IA) by Parties and Party Agents (via CPC00674). In light of the assessments we have prepared recommendations and decisions are sought as to whether these CP's should be progressed.

2 Summary of Change Proposals for Progression

2.1 CP1315 – Maintenance of Outstation Types as part of Compliance and protocol approval

2.1.1 CP1315 seeks to allow Outstation information to be kept more up to date by removing the Valid Set for the Outstation Type data item (J0471), listed in the DTC, and replacing it with a reference to the Protocol and Compliance Approval List maintained by ELEXON.

2.1.2 We issued CP1315 for impact assessment (via CPC00669) in October 2009. We received 10 responses; of these 6 agreed, 2 disagreed and 2 were neutral. We have included the detailed assessment report for CP1315 within attachment A.

2.1.3 Although we received majority support from industry, you raised some concerns at your meeting on the 1 December[1], relating to the potential loss of data integrity as a result of removing the initial validation of the Outstation information. You therefore deferred a decision on CP1315 and requested that we consult with MRA parties before you would make a decision.

2.1.4 We received 11 MRA consultation responses (please refer to Attachment B); of these 7 agreed, 2 disagreed and 3 were neutral. The individual comments were also very similar to those we received in the CP industry consultation phase. Our responses to those comments are detailed in the SVG106 Change Proposal Progression Paper.

[1] Please refer to the following link for the SVG Minutes ''SVG106 Minutes'

2.1.5 The majority of industry responses support CP1315 and the view that it will avoid the existing delays in notifying parties of new Outstation Types (which currently results in numerous workarounds and manual processes being used to ensure the correct outstation types are defined). We therefore recommend that you:

- **APPROVE** CP1315 for implementation in the November 2010 Release.

2.2 CP1322 - Review of the CSD Architectural Principles Document

2.2.1 We raised CP1322 on 8 January 2010. We issued CP1322 for impact assessment (via CPC00674) in January 2010.

2.2.2 CP1322 aims to revise the Code Subsidiary Document (CSD) Architectural Principles Document (CSD Architectural Principles Document) to correct a number of inaccuracies as well as to address out-of-date information. We believe that these improvements will ensure that it is easier and more efficient for the Imbalance Settlement Group (ISG) and Supplier Volume Allocation Group (SVG) to use when approving updates to CSDs.

2.2.3 We received 9 responses to the industry impact assessment; of these 8 agreed and 1 was neutral. Respondents noted that this was largely a housekeeping exercise to bring the CSD Architectural Principles Document in line with current practices. No comments were made on the suggested redlined text.

2.2.4 We recommend, based on CP1322 aligning the CSD Architectural Principles Document with current working practices, and majority industry support, that you:

- **ENDORSE** CP1322 for implementation in the June 2010 Release.

2.3 CP1323 - Review of the Qualification Self Assessment Document

2.3.1 We raised CP1323 on 8 January 2010. We issued CP1323 for impact assessment (via CPC00674) in January 2010.

2.3.2 CP1323 aims to revise BSCP537 Appendix 1 'Self Assessment Document (SAD)' to correct a number of areas of concern that have arisen following its implementation.

2.3.3 We received 10 responses to the industry impact assessment; all of the respondents agreed with the change. Respondents noted that this was largely a housekeeping exercise but suggested that it would strengthen the SVA qualification process by introducing a section on the need for the applicant to demonstrate its PARMS reporting ability. No comments were made on the suggested redlined text.

2.3.4 We recommend, based on CP1323 clarifying the relevant requirements on market participants and making the processes in the SAD easier to follow, and unanimous industry support, that you:

- **APPROVE** CP1323 for implementation in the June 2010 Release.

2.4 CP1324 - Access Requirements for Offshore Metering Installations at 132kV or Above

2.4.1 ELEXON raised CP1324 on 5 January 2010. We issued CP1324 for impact assessment on 8 January 2010, via CPC00674.

2.4.2 CP1324 aims to mitigate the safety risks associated with accessing offshore installations by reducing the need to access offshore installations, while maintaining the integrity of Settlement.

2.4.3 We received 10 responses to the impact assessment. Five respondents agreed CP1324 should be implemented and four were neutral. One respondent disagreed with CP1324 and raised a number of issues, and one respondent who supported CP1324 suggested some amendments to the proposed Code of Practice (CoP) changes around dual redundancy of communications. We have considered the comments, spoken to respondents and obtained input from the expert group that developed the CP1324 proposals.

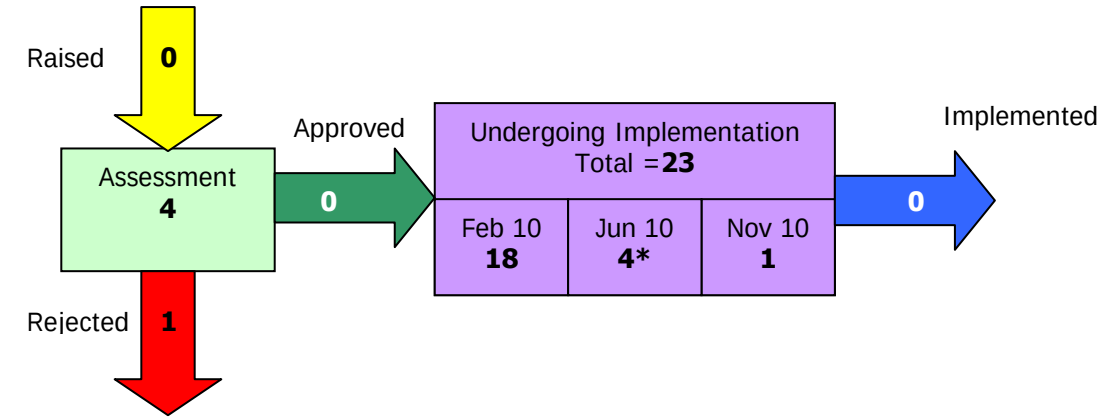
2.4.4 Based on the expert group views we recommend that no changes should be made to the CP1324 solution. We recommend that minor changes amendments should be made to the redlined changes to Code of Practice 1 (CoP1) and Code of Practice 2 (CoP2) to clarify the meaning of the term 'Outstation System' when applied to offshore Metering Systems.

2.4.5 We recommend, based on the conclusions of the expert group and the support of the majority of respondents to the industry impact assessment, that you:

- **AGREE** our recommended amendments to the redline text issued for impact assessment; and
- **APPROVE** CP1324 for implementation in the June 2010 Release.

3 Summary of Change Proposals for Progression

3.1 There are currently **27** open CPs, the SVG own **16** CPs, the ISG and SVG co-own **7** CPs, and the ISG own the remaining **4** CPs. No new CPs have been raised since the last SVG meeting.



Please note:
- The numbers in the boxes indicate current number of CPs in a given phase.
- The numbers in arrows show the variance in the past month.

3.2 There are currently no open DCPs.

4 Recommendations

4.1 We invite you to:

a) **APPROVE** CP1315 for inclusion in the November 2010 BSC Systems Release;

b) **ENDORSE** CP1322 for inclusion in the June 2010 BSC Systems Release;

c) **APPROVE** CP1323 for inclusion in the June 2010 BSC Systems Release;

d) **AGREE** our recommended amendments to the CP1324 redline text issued for impact assessment; and

e) **APPROVE** CP1324 for inclusion in the June 2010 BSC Systems Release.

List of Appendices:

Appendix 1 – Detailed Analysis of CP1322
Appendix 2 – Detailed Analysis of CP1323
Appendix 3 – Detailed Analysis of CP1324
Appendix 4 – Release Information

List of Attachments:

Attachment A – Detailed Analysis of CP1315
Attachment B – CP1315 MRA consultation responses
Attachment C – CP1322 Redline Changes to (CSD) Architectural Principles Document
Attachment D – CP1323 Redline Changes to BSCP537
Attachment E – CP1324 Redline Changes to CoP1
Attachment F – CP1324 Redline Changes to CoP2
Attachment G – CP1324 Redline Changes to BSCP05
Attachment H – CP1324 Redline Changes to BSCP06
Attachment I – CP1324 Redline Changes to BSCP27
Attachment J – CP1324 Redline Changes to CDCA SD
Attachment K – CP1324 Redline Changes to CDCA URS

Appendix 1 – Detailed Analysis of CP1322 'Review of the CSD Architectural Principles Document'

5 Why Change?

5.1 Background

5.1.1 The Code Subsidiary Documents (CSDs) Architectural Principles Document (CSD Architectural Principles Document) sets out general principles concerning the contents of the suite of CSDs which gives more detailed guidance on the contents of each type of document and also captures the principles governing the modification of existing CSDs and the creation of new CSDs.

5.1.2 We raised CP1322 on 8 January 2010 and subsequently issued it for impact assessment (via CPC00674) in January 2010.

5.2 The Problem

5.2.1 The CSD Architectural Principles Document has not undergone substantial revision since it was published as part of the BSC Baseline in November 2006.

5.2.2 Following a review of the document in 2009 we noted that there are a number of inaccuracies, as well as out-of-date information which makes it difficult for the ISG and SVG to use the document when approving updates to CSDs.

5.2.3 CP1322 aims to revise the CSD Architectural Principles Document to correct a number of inaccuracies as well as to address the out-of-date information.

6 Solution

6.1 The Applicable BSC Objectives should be inserted into section 1.4.3, as they currently do not sit in the section despite the existing text suggesting that they should.

6.2 Section 3.1, concerning BSCPs, requires a substantial overhaul. The section refers to Category 1 and Category 2 BSCPs, which do not and have never existed. Category 1 and Category 2 Configurable Items have existed since the implementation of CP1170 in February 2007, and all BSCPs are Category 1 Configurable Items. I t would add value if a full and accurate explanation of Category 1 and Category 2 CSDs was added to section 3.1.3, together with some guidance as to what constitutes a CSD, what constitutes a Configurable Item, and the differences (and similarities) between the two. Section 3.1.4 should also specify that all BSCPs contain details of other BSCPs with which they interface. These changes will provide added clarity for those responsible for producing revisions to CSDs in the future.

6.3 Section 3.2 refers to multiple PSLs. There is now one single PSL, with the functional requirements having been moved to relevant BSCPs as part of CP1182. This should be reflected in the text.

6.4 Section 3.3, regarding the Codes of Practice, has no reference to the provisions of CoP 10, introduced in February 2009. A reference to these provisions should be added.

6.5 Section 3.4.3 refers to the SVAA BSC Service Description consisting of seven SVAA Service Lines (SSLs). The SSLs were withdrawn in April 2009 with the introduction of a unified SVAA Service Description. The reference to the SSLs should be removed and replaced with a reference to the SVAA Service Description.

6.6 Section 3.4.4 suggests that a Service Description should contain a requirement for the provision by a BSC Agent of a help desk service. Individual BSC Agent Help Desks have been combined into the BSC Central Services Desk, and therefore this reference should be removed.

6.7 Section 3.7 suggests that the Reporting Catalogue covers both SVA and CVA reporting. The document covers only CVA Reporting; this sentence should be amended accordingly.

6.8 A number of miscellaneous typographical revisions should be made.

6.9 These changes can be found in the redlined text for CP1322, included as Attachment A.

7 Intended Benefits

7.1 The Panel, or its delegated authority in the form of Panel Committees, is required to assess and approve changes to CSDs in accordance with the CSD Architectural Principles Document. It is important that the CSD Architectural Principles Document is of sufficient quality to provide a basis for the production, review and approval of future changes to CSDs.

8 Industry Views

8.1 We issued CP1322 for impact assessment in January 2010 (via CPC00674). We received 9 responses; of these 8 agreed and 1 was neutral.

8.2 Industry participants did not anticipate the change as having any adverse impact on their organisation. Respondents made no further comments on this change.

9 Impacts and Costs

Market Participant	Cost/Impact	Implementation time needed
BSC Agent	None	-
ELEXON (Implementation)	2.5 man days - £600 (implementing documentation changes).	June 2010 Release suitable
Industry	None	June 2010 Release suitable

10 Implementation Approach

10.1 We recommend that this documentation-only change be implemented as part of the June 2010 Release.

11 Recommendation

11.1 We recommend, based on CP1322 aligning the CSD Architectural Principles Document with current working practice, and majority industry support, that you:

- **ENDORSE** CP1322 for implementation in the June 2010 Release.

Contact the Lead Analyst:

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Table 1: Industry Impact Assessment Summary for CP1322 – Review of the CSD Architectural Principles Document

IA History CPC number	CPC00674	Impacts	CSD Architectural Principles Document		
Organisation		**Capacity in which Organisation operates in**		**Agree?**	**Days to Implement**
Gemserv		MRASCo		Yes	-
Independent Power Networks Ltd		LDSO, UMSO, SMRA		Yes	-
E.ON Energy Services Ltd		MOA, NHHDC/DA		Neutral	-
EDF Energy		Supplier, NHH Agent, HH MOA		Yes	-
SAIC		Supplier, LDSO, HHDA, NHHDA, HHDC, NHHDC, HHMOA, NHHMOA		Yes	-
E.ON		Supplier		Yes	-
Npower Ltd		Supplier/Supplier Agent		Yes	-
Scottish and Southern Energy		Supplier/Generator/Trader/Party Agent/Distributor		Yes	-
British Gas		Supplier		Yes	-

Table 2: Impact Assessment Responses[2]

Organisation	Agree?	Comments	Impacted?	ELEXON Response
Gemserv	Agree	-	-	-
Independent Power Networks Ltd	Agree	This is largely a house keeping exercise to bring the CSD Architectural Principles Document in line with current practices.	-	-
E.ON Energy Services Limited	Neutral	-	-	-
EDF Energy	Agree	-	-	-
SAIC	Agree	-	-	-
E.ON	Agree	-	-	-
Npower Limited	Agree	-	-	-
Scottish and Southern Energy	Agree	-	-	-
British Gas	Agree	-	-	-

Comments on the redline text

We did not receive any comments on the redlined text.

[2] Please note that we have only included responses in this table where the respondent provided additional information.

Appendix 2 – Detailed Analysis of CP1323 'Review of the Qualification Self Assessment Document'

1 Summary

1.1 Background

1.1.1 We raised CP1323 on 8 January 2010 and subsequently issued it for impact assessment (via CPC00674) in January 2010.

1.2 The Problem

1.2.1 P197 'SVA Qualification Process Review' was implemented in August 2007. Following its implementation we have identified a number of potential improvements to the Self Assessment Document (SAD), which we believe will address the following areas of concern:

- The SAD does not provide satisfactory focus on the obligations set out in BSCP520 for the role of a Meter Administrator (MA);
- Applicants completing the SAD are not required to demonstrate ability to create and send PARMS reports, and some new participants have been unable to do this; and
- Some minor errors in the wording and formatting of the SAD documentation (housekeeping changes) require attention.

1.2.2 We believe that BSCP537 Appendix 1 'Self Assessment Document (SAD)' should be revised in order to address the above areas.

2 Solution

2.1 The proposed solution seeks to rectify the issues described above by the following actions:

- Revising the questions in the MA section of the SAD to align with BSCP520;
- Incorporating a question that relates to PARMS data submission in the specific SAD sections for the appropriate roles; and
- Actioning the required housekeeping changes to rectify the minor errors in the wording and the formatting of the document.

2.2 These changes can be found in the redlined text for CP1323, included as Attachment B.

3 Intended Benefits

3.1 Aligning the MA section in the SAD with the current obligations within BSCP520 will enable MA Applicants to clearly demonstrate how they are able to meet BSC obligations in their submission of the SAD.

3.2 The inclusion of a question relating to PARMS submissions will enable Applicants operating relevant roles to clearly demonstrate how they are able to meet the obligations to produce PARMS submissions as set out in BSCP533, thereby improving the quality of the data as handled by Suppliers.

3.3 Correcting the housekeeping changes within the SAD will improve the overall quality of the Document for new participants, removing various inconsistencies and negating the issues that participants experience when completing the document at present.

4 Industry Views

4.1 We issued CP1323 for impact assessment in January 2010 (via CPC00674). We received 10 responses, in unanimous agreement.

4.2 Industry participants did not anticipate the change as having any adverse impact on their organisation. Respondents made no further comments on this change.

5 Impacts and Costs

Market Participant	Cost/Impact	Implementation time needed
BSC Agent	None	None
ELEXON (Implementation)	5.25 man days - £1,260 (implementing documentation changes).	June 2010 Release suitable
Industry	None (the only impact will occur when participants need to submit new SAD forms using the revised document)	June 2010 Release suitable

6 Implementation Approach

6.1 We would recommend that this documentation-only change be implemented as part of the June 2010 Release.

7 Recommendation

7.1 We recommend, based on CP1323 clarifying the relevant requirements on market participants and making the processes in the SAD easier to follow, and unanimous industry support, that you:

- **APPROVE** CP1323 for implementation in the June 2010 Release.

Contact the Lead Analyst:

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Table 1: Industry Impact Assessment Summary for CP1323 – Review of the Qualification Self-Assessment Document

IA History CPC number	CPC00674	Impacts	BSCP537 Appendix 1 'Self Assessment Document'	
Organisation		**Capacity in which Organisation operates in**	**Agree?**	**Days to Implement**
Gemserv		MRASCo	Yes	-
Independent Power Networks Ltd		LDSO, UMSO, SMRA	Yes	-
Power Data Associates Ltd		MA	Yes	-
E.ON Energy Services Ltd		MOA, NHHDC/DA	Yes	-
EDF Energy		Supplier, NHH Agent, HH MOA	Yes	-
SAIC		Supplier, LDSO, HHDA, NHHDA, HHDC, NHHDC, HHMOA, NHHMOA	Yes	-
E.ON		Supplier	Yes	-
Npower Ltd		Supplier/Supplier Agent	Yes	-
Scottish and Southern Energy		Supplier/Generator/Trader/Party Agent/Distributor	Yes	-
British Gas		Supplier	Yes	-

Table 2: Impact Assessment Responses[3]

Organisation	Agree?	Comments	Impacted?	ELEXON Response
Gemserv	Agree	-	-	-
Independent Power Networks Ltd	Agree	The proposal mainly implements housekeeping changes but also strengthens the SVA qualification process by introducing a section on the need for the applicant to be able to demonstrate their PARMs reporting ability.	-	-
Power Data Associations Ltd	Agree	Documentary impact if/when respondent needs to update SAD return. This should have been captured as an impact when the CP on changes to BSCP520 was considered by ELEXON. The new form structure is not easy to complete.	Yes	We have discussed this comment with the respondent, who is happy with the CP and redlining and who agrees that no further action should be taken. CP1291 and CP1292 were implemented in November 2009 and amended BSCP520 to clarify Meter Administrator requirements relating to Equivalent Meters and PECU arrays. These changes to BSCP520 were developed by the Meter Administrator Expert

[3] Please note that we have only included responses in this table where the respondent provided additional information.

				Group, who identified no impact on BSCP537 Appendix 1 during their discussions. We envisage that CP1323 will go a long way to ensuring that the SAD is more robust and fit for purpose.
E.ON Energy Services Limited	Agree	Care will need to be taken that the latest version of the SAD is completed in the course of Qualification activity.	Yes	-
EDF Energy	Agree	-	-	-
SAIC	Agree	-	-	-
E.ON	Agree	-	-	-
Npower Limited	Agree	-	-	-
Scottish and Southern Energy	Agree	-	-	-
British Gas	Agree	-	-	-

Comments on the redline text

We did not receive any comments on the redlined text.

Appendix 3 – Detailed Analysis of CP1324 'Access Requirements for Offshore Metering Installations at 132kV or Above'

1 Why Change?

1.1 We raised CP1324 on 5 January 2010, following review of the BSC requirements and arrangements for access to offshore Metering Equipment by an expert group[4]. CP1324 recognises that there are greater safety risks associated with accessing offshore installations, and aims to minimise these risks by implementing the expert group's proposals.

1.2 Following the introduction by Ofgem and the Department of Energy and Climate Change (DECC) of a regulatory regime for offshore transmission, Go-Live of the Offshore Transmission Operator (OFTO) arrangements is planned for June 2010. The OFTO arrangements will incorporate Plant and Apparatus of offshore installations into the Total System, meaning the GB Total System will extend to offshore installations and Settlement Metering Equipment will be installed on offshore platforms.

1.3 We asked the industry experts to consider relevant Balancing and Settlement Code (BSC) requirements with respect to the additional health and safety risks associated with access to offshore Metering Equipment, and to evaluate any potential technical or procedural changes to reduce the need for offshore visits.

1.4 The expert group met twice to consider the BSC access requirements, and concluded that there are significantly higher risks associated with accessing offshore Metering Systems compared with those situated on land. Weather conditions will be significant, and may impact Registrants of Metering Equipment (who are responsible for ensuring the relevant timescales are met). The group's proposals include strengthening the required redundancy in communications equipment in the relevant Codes of Practice (CoPs) to allow the frequency of site visits to be reduced without an adverse affect on Settlement integrity.

2 Solution

2.1 CP1324 would introduce changes in the following areas. The proposed changes are documented in detail in CP1324 and are summarised below.

1) Communication Redundancy

- Change CoP2 to require two Outstation Systems where each Outstation will be connected to two communication lines.
- Clarify the term 'communication line' in CoP1 and CoP2, such that a communication line is one which is uniquely identifiable by its number or address.

2) Technical Audits

Change the Technical Assurance Agent (TAA) audit process in BSCP27 'Technical Assurance of Half Hourly Metering Systems for Settlement Purposes' so that:

- The TAA is required to give Registrants 90 Working Days notice of selection of an offshore Metering System for technical audit (instead of the 20 Working Days for a conventional site).

[4] Expert group formed at the request of the ISG; see ISG103/04

- The technical audit of offshore Metering Systems may be conducted within 20 Working Days of the scheduled date.
- The TAA shall notify ELEXON if a scheduled visit cannot take place for health and safety reasons within 20 Working Days of the scheduled date, and such cases may be referred to the Performance Assurance Board for further consideration.

3) Metering Faults

Change BSCP06 'CVA Meter Operations for Metering Systems Registered in CMRS' to introduce a process whereby the Meter Operator Agent (MOA) can notify ELEXON if timescales for the repair of Metering Equipment faults cannot be met for health and safety reasons only.

- The minimum requirements for repairs would not be changed.
- Notification to ELEXON would be in the form of an assessment of the risk to Settlement and would detail the control measures in place.
- ELEXON would bring any uncontrolled risks to the attention of the ISG.

4) Meter Advance Reconciliations (MARs)

- Change MAR process in BSCP05 'Meter Advance Reconciliation for Central Volume Allocation' so that for offshore installations the first MAR shall be within 3 months and subsequent MARs will be every 12 months.
- Change the Central Data Collection Agent (CDCA) User Requirement Specification (URS) and CDCA Service Description (SD) so the functional requirements reflect the change to BSCP05.

2.2 Redlined changes for all the impacted documents, as described above, are attached. One respondent to the CP1324 industry impact assessment suggested the changes to CoPs should be amended. This is covered in detail in section 6 below. We do not recommend any changes should be made to the redlining as result of these comments. However, we do recommend that the redlining for CoP1 and CoP2 should be amended to clarify the meaning of 'Outstation System' in relation to offshore Metering Systems (see section 5 for further details).

3 Intended Benefits

3.1 Implementation of the proposals in CP1324 would ensure the continued integrity of Settlement while taking due consideration of the risk to the safety of personnel and the practicalities of accessing offshore installations. The expert group that developed these proposals believes that CP1324 is a carefully considered and balanced approach to achieving this aim.

4 Industry Views

4.1 We issued CP1324 for impact assessment on 8 January 2010, via CPC00674. We received ten responses. Of these, five respondents agreed CP1324 should be implemented and four were neutral. One respondent disagreed with CP1324.

4.2 Three respondents identified that they would be impacted by CP1324. These respondents identified impacts as MOA, Half Hour Data Collector (HHDC) and Supplier. Impacts are limited to changes to internal processes/procedures and training; only one respondent reported that they require a lead time for implementation (30 days).

4.3 Two respondents commented that the proposed provisions would go some way to minimising the risks associated with offshore metering installations, and that the proposed change is an appropriate improvement to the current processes.

4.4 One respondent submitted a substantial number of comments against CP1324. The comments and our responses to them can be found in the table of industry impact assessment responses. In summary, we concluded that though some of the comments might have merit generally, none of the comments are applicable specifically to offshore access arrangements or the proposals contained in CP1324.

4.5 We notified the respondent of our responses to his comments. The respondent acknowledged that many of the issues raised were also applicable in onshore situation. Therefore they are not applicable specifically to CP1324.

4.6 However, the respondent maintained that CP1324 would introduce ambiguity around dual or single connections to the outstation systems. We agree with this, and therefore recommend adding text to the proposed redlined changes to CoP1 (paragraph 3.23, now 3.24 in CP1324 redlined version) and CoP2 (paragraph 3.21, now 3.22 in CP1324 redlined version) to clarify this area, as follows:

> ***Outstation System***
>
> *Outstation System means one or more Outstations linked to a single communication line, except in the case of offshore Metering Systems where an Outstation System means one or more Outstations linked to two communication lines.*

4.7 One respondent, who supported CP1324, had comments on the redlined changes to the CoPs which were based on their disagreement with the measures proposed to ensure dual redundancy in communication lines. We consulted the expert group on these comments. No members of the group supported the respondent, and we therefore recommend that no change should be made to the redlining as a result of these comments. The details of group members' responses are provided in section 6 below, which explains the reasons for their views.

5 Representations from members of the expert group

5.1 A response to the CP1324 impact assessment questioned the proposed changes around communication lines in the CoPs (see redline text comments table). We asked for the views of the expert group that developed the CP1324 proposals.

5.2 The expert group had agreed that dual redundancy in communication lines should be provided to reduce the necessity of visiting sites in the event of metering faults. The group also agreed that 'Communication Line' should be defined to mean separate communications addresses, meaning dual redundancy could be provided via a single piece of communication technology.

5.3 The respondent suggested that this does not meet the objective of dual redundancy, and would allow a fault in the common communications technology to potentially adversely impact Settlement. Essentially the respondent suggested that to fulfil the objective of dual redundancy it would be necessary to install two different communication technologies at offshore sites.

5.4 Five members of the expert group responded with comments. The only member from a company operating as a Supplier (Centrica) stated that they would strongly object to such a requirement to install two different communication technologies at each offshore site. Windfarms (already built or under construction) that do not have two means of communication would be impacted. The

member noted that changing the requirements in this way at this stage would increase uncertainty and be likely to incur significant cost.

5.5 The other four members who commented were from metering businesses[5]. None supported the respondent's suggestion to require two different communication technologies.

5.6 One member noted that the expert group had discussed this point and agreed that it was not reasonable to require a windfarm operator to install an additional means of communication to an offshore platform, e.g. an additional telecoms cable. They also commented that group members had stated that the telecoms cable was commonly part of the main offshore cable, so if the cable were to fail there would be more significant problems than reading meters.

5.7 The member believed that the proposed requirement to install an additional communication address, and as such an additional modem, should considerably reduce the likelihood of communication failure and was reasonable. Therefore while they agreed with the principle of the respondent's comments, the member stood by the group's proposal as they believed it to be a pragmatic and cost effective solution.

5.8 Another member commented that, while they could understand the objection, experience with onshore sites shows though a common mode of communication (Public Switched Telephone Network, PSTN) is used for both primary and secondary outstations, and often the same type of outstation and modem is used, it is extremely unlikely for both lines to be affected by a fault. The member accepted that the impact of a fault relating to an offshore site might be greater than an onshore fault due to the difficulties associated with accessing offshore installations. But they believed that, balanced against the low probability of a fault occurring, the risk was not great enough to justify requiring another communication medium for offshore sites.

5.9 This member echoed the concern that such a requirement would be likely to incur considerable costs (e.g. if a radio or satellite communications system had to be installed along with the main communication cable). They also observed that if a fault occurred in the cable containing the metering communication medium, problems with metering data would probably be a relatively minor concern.

5.10 Two group members emphasised technical issues with the suggestion. A member noted that requiring two different communication technologies could in many cases be difficult to implement as communication installations are constrained by the infrastructure of the offshore platform. Requiring only different 'comms addresses' would indeed allow use of a single communication medium (hub, etc) meaning a fault could potentially cause a total communication failure. But the cable containing the metering data communication medium will be essential to operation of the offshore platform, so will almost certainly have a good deal of redundancy built into it.

5.11 In summary, the group members believed they had considered the issue raised when they originally developed the CP1324 proposals, and still believed that the proposals around dual redundancy represent a sensible and cost effective approach to managing the risk of faults.

[5] Siemens Metering Services, E.ON Engineering Manager, EDF Energy Major Business Metering and SSE Metering Ltd.

6 Impacts and Costs

Market Participant	Cost/Impact	Implementation time needed
CDCA	The CDCA will: • Operate under the revised MAR process; • Work within the arrangements proposed for resolution of metering faults by MOAs; and • Where required work with ELEXON and MOAs to resolve longer term faults. This alternative mode of work does not affect any systems, impacts on processes are minimal, i.e. no CDCA implementation/ongoing costs.	June Release suitable
ELEXON	Implementation: 8 ELEXON Man Days (equating to £1,920).	June Release suitable
Supplier, MOA, HHDC	No cost estimates were provided. Three IA respondents identified impacts in their capacity as an MOA and a HHDC, i.e. changes to internal processes/procedures and training. Only one respondent reported that they require a lead time for implementation (30 days). One IA respondent identified similar minimal impacts in their capacity as a Supplier, but no other respondents did (and most of the respondents operate as Suppliers).	30 days - June Release suitable

7 Implementation Approach

7.1 CP1324 would be implemented in the June 2010 Release. This coincides with the planned Go-Live of the OFTO arrangements in June 2010.

8 Preliminary investigation of possible CDCA change

8.1 As part of assessment of CP1324 we considered a possible change to improve the process of the CDCA investigating communication line faults. If there is a fault with a communication ('comms') line at present the CDCA must notify the Registrant/MOA of the affected Metering System. The MOA would then attend to the issue, and may resolve the fault by providing an alternative second comms address. It is not proposed to change this as part of CP1324.

8.2 Under this current process the second comms address would be provided via the Meter Technical Details (MTD) registration process in BSCP20 'Registration of Metering Systems for Central Volume Allocation'. We understand that to be compliant with CoPs 1 and 2 a second comms address must be provided, but that the second address need not be registered with CMRS unless a fault occurs with the currently registered address (the 'primary' address).

8.3 In the course of the BSC Agent impact assessment an alternative process was suggested whereby the CDCA would be able to hold a back-up comms address as well as the primary address. In the case of a fault the CDCA could then use the back-up address to confirm whether it is the comms line or the primary address that is faulty. The advantage of this approach would be the potential for the CDCA to utilise the alternative comms address without recourse to the Registrant/MOA.

There may also be benefits for both Registrants and ELEXON due to reduced usage and administration of the BSCP20 meter technical details registration process.

8.4 However, we are not progressing this possible change as part of CP1324 for several reasons, foremost of which is that the minor CDCA system changes required could jeopardise implementation of CP1324 as part of the June Release (which we are targeting because it will coincide with the introduction of the OFTO arrangements). Note that since CP1324 does not impact CDCA systems, no efficiency benefit is sacrificed by separately progression of this possible process improvement. Additionally, we want to get the views of the expert group and to further consider the suggested solution and the identified implementation impacts.

8.5 We therefore conclude that it is prudent to progress this possible change, as appropriate, separately to CP1324.

9 Conclusion

9.1 The expert group that developed the changes that constitute CP1324 believe that this set of changes would ensure the continued integrity of Settlement while taking into due consideration the risk to the safety of personnel and the practicalities of accessing offshore installations. We have addressed all comments raised in the industry impact assessment and the ELEXON, Party and BSC Agent implementation impact would be minimal. We therefore conclude that CP1324 should be approved for implementation in the June 2010 Release.

10 Recommendations

10.1 We recommend, based on the conclusions of the expert group and the support of the majority of respondents to the industry impact assessment, that you:

- **AGREE** our recommended amendments to the redline text issued for impact assessment; and
- **APPROVE** CP1324 for implementation in the June 2010 Release.

Contact the Lead Analyst:

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Table 1: Industry Impact Assessment Summary for CP1324 - Access Requirements for Offshore Metering Installations at 132kV or Above

IA History CPC number	CPC00647	Impacts	Code of Practice 1, Code of Practice 2, BSCP05, BSCP06, BSCP27, CDCA URS, CDCA Service Description		
Organisation		**Capacity in which organisation operates**	**Agree?**	**Impact?**	**Days to Implement**
Gemserv		MRASCo Ltd	Neutral	No	0
Independent Power Networks Limited		LDSO, UMSO, SMRA	Neutral	No	0
E.ON Energy Services Limited		MOA NHHDC-DA	Neutral	No	0
EDF Energy		Supplier, NHH Agent and HH MOP	Yes	No	0
SAIC on behalf of: ScottishPower Energy Management Ltd, ScottishPower Generation Ltd, ScottishPower Energy Retail Ltd, SP Manweb plc, SP Transmission Ltd, SP Distribution Ltd		Supplier, LDSO, HHDA, NHHDA, HHDC, NHHDC, HHMOA, NHHMOA	Yes	Yes	30
E.ON		Supplier	Yes	No	0
NPower Limited		Supplier / Supplier Agents	No	Yes	0
Scottish and Southern Energy		Supplier/Generator/ Trader / Party Agent / Distributor	Yes	Yes	0
British Gas		Supplier	Yes	No	0
British Energy		Generator/Supplier/Trader non-physical/CVA Meter Operator	Neutral	No	0

Table 2: Impact Assessment Responses[6]

Organisation	Agree	Comments	Impact	ELEXON Response
Gemserv	Neutral	-	No	-
Independent Power Networks Limited	Neutral	-	No	-
E.ON Energy Services Limited	Neutral	**Comment -** We would agree that the provisions proposed would go some way to minimising the risks associated with metering installations at offshore locations. However we do not anticipate this having a direct impact on our activities.	No	**-**
EDF Energy	Yes	-	No	-
SAIC on behalf of: ScottishPower Energy Management Ltd; ScottishPower	Yes	**Role in which organisation is impacted:** MOA, HHDC, Supplier **Impact:** Impact will be only be in regards to internal processes. ScottishPower supports the CP and believes it is an appropriate improvement to the current processes. **Would implementation in the proposed Release have an adverse**	Yes	**-**

[6] Please note that we have only included responses in this table where the respondent provided additional information.

Generation Ltd; ScottishPower Energy Retail Ltd; SP Manweb plc; SP Transmission Ltd; SP Distribution Ltd.		**impact on your organisation?** No		
E.ON	Yes	-	No	-
NPower Limited	No	**Would implementation in the proposed Release have an adverse impact on your organisation?** No **Associated costs**: None **If yes, then for which role is your organisation impacted?** RWE Innogy **Please state what the impact is:** Please see Question 6 *(i.e. comments below)*. **Would implementation in the proposed Release have an adverse impact on your organisation?** No **Associated costs:** Unknown at this stage **Any other comments:** **1. Communication Redundancy etc** The proposal says "each outstation will be connected to two communication lines", while the redlined document COP 1 (and COP2) give the definition of an outstation system as having a single Communication Line. Should this perhaps refer to a shared Communication System (and define that term). The definition of Communication Line as a line or link dedicated to an Outstation System ... The term dedicated precludes any other traffic on that line or link. That is not how modern communication systems are generally constructed. Use is made of shared traffic on networks, and the number of fibres from onshore to offshore is limited. The use of Virtual Local Area Networks for metering should be explicitly permitted. The cost of providing dedicated lines for metering purposes would be high. The identification of Communication Lines by a unique number: unique within what scope? Is this unique to the registrant, in which case he will manage the identification, or unique across the whole BSC system, in which case it must be done centrally. There is no definition of the procedure. Possibly CTN or PSTN	Yes	1. These issues may be valid concerns but they are not limited to offshore sites. They might be resolved by a separate CP in future.

		uniqueness is ensured if the numbers proposed are actually telephone numbers. However, IP addresses are not allocated to communications lines, but to communications ports on devices. Any device with two communications ports therefore has two IP addresses. An outstation system comprising 4 main and 4 check meters with embedded outstation software in each meter, and connected via two network switches and two fibres back to on-shore could have 8 or 16 IP addresses, depending whether each meter has one or two IP connections. The use of private domains (10.x.y.z addresses) within companies means that different outstations in different companies may have the same IP address, and these can be translated by various means (Network Address Translation or proxy servers) into externally visible addresses. Particularly with IP facilities, firewalls and security are major issues. **2. Transport to offshore locations** There is nothing mentioned in any of the changed documents about who is responsible for providing transport to site, and for providing rescue cover. The availability of boats and rescue cover will be a major issue for MOAs and CDCA and TAA. Providing such facilities for fault repair at short notice will have a high cost impact. A visit to a meter is not a man in a van, followed by a short walk to an accessible installation, but a team of people in a boat that costs £k per day to operate. The impact on other work (not doing it in time) may also be considerable if a boat must be diverted. If the MOA has their own boat and crew, they may be in the wrong location. Travel time must be taken into account. Much of this may be for bipartisan arrangements between the MOA and the Registrant, but there are other parties such as CDCA who may attend site. **3. Metering Equipment Faults and Performance Standards** The MOA, not the Registrant is responsible for meeting performance standards. The relevant standards are: ***Subprocess*** *Fault repairs* ***Performance Measure***		2. With regard to the issue that 'There is nothing mentioned in any of the changed documents about who is responsible for providing transport to site, and for providing rescue cover' we note that there the current arrangements contain no such provisions. We do not see justification for treating offshore sites differently in this respect. Section L6 of the BSC is clear that Registrants are to secure the necessary arrangements for site access for all parties including the TAA and CDCA. 3. Registrants are responsible for their agents performance (see BSC Section J 1.1.1 b))

		Time to rectify faults which would constitute a category 1 or category 2 non compliance as defined in BSCP27 *[Category 1 Non Compliance A non-compliance has been identified which is deemed to be currently affecting the quality of data for Settlement purposes* *Category 2 Non Compliance A non-compliance has been identified which is deemed to have the potential to affect the quality of data for Settlement purposes]* ***Service Levels*** *(i) 95% rectified within 5 working days of receipt of notification;* *(ii) 99% rectified within 15 working days of notification.* As the requirement is on the MOA, not the registrant, does 95% refer to 95% of all faults that a particular MOA is responsible for? Can they offset good performance onshore against worse performance off shore, and one Registrant against another? Do existing onshore MOAs have the experience to operate off shore? A new MOA operating only offshore could be at a significant disadvantage. As described above, access to offshore locations will be a major issue, not only for the weather. It seems unlikely to me that it would be possible for an MOA to economically provide 95% fixing of category 1 and category 2 faults offshore within 5 working days, unless he had his own boat and crew stationed locally, and they would have little to do most of the time. In practice each system will have main and check meters on each circuit, HV SCADA repeat readings, and analogue measurements. Each turbine will have power output readings via the wind turbine control system. Loss of a single meter will have no commercial impact, loss of main and check will have an administrative impact, requiring manual adjustment and/or agreement of data, but minor commercial impact. Is loss of a single meter category 2? Much of the aim of this modification is to provide redundancy of communications, so that fewer faults are category 1, but if any failure of the standby system is counted as category 2, the number of those faults could be higher, due to the increased number of components, and to configuration complexity. Our view is that we should segregate offshore and onshore metrics, and put a less onerous requirement on faults that require an offshore expedition as against		The requirement falls on MOAs by virtue of the MOA service line. MOAs on the review group who are already meeting these obligations offshore didn't believe this to be an issue. An MOA specialising in offshore metering may run into problems if meeting timescales becomes an issue. In this case ELEXON would be notified via this new process and would bring the situation to the attention of the ISG. A Category 2 fault is one that has the potential to impact Settlement. Therefore this is a category 2 fault. Relying on other forms of metering for rectifications in the event of a catastrophic fault is one thing but the BSC sets out its own standards for metering for its independent integrity. We believe it is difficult to argue that the integrity of Settlement could be compromised because access is difficult or carries risk. For instance, access to nuclear sites could potentially be problematic but we don't see need to change in this area. The additional redundancy in comms lines has the potential to make faults repairs less urgent, and therefore the expert group concluded that 15 days to

		those that perhaps only require work on-shore, and also differentiate between category 1 and category 2, at least so far as category 2 faults could include some loss of redundancy, and hence some potential to loss of data quality. **4. "Checks at least every 12 months"** This term is ambiguous, if least refers to 12. For instance 13 is at least 12. 11 is less than 12 so is not OK. There should be some capability to schedule a visit later, in order for them not to be dragged forwards in the year as they get scheduled for 11.5 months say, and the limit should be in days, as a month is not a fixed time period. A change similar to this was recently approved in relation to visits to identify unoccupied premises.		rectify category 2 faults is sufficient. If it is shown in future that this requirement cannot be met then a further change to address that issue could be progressed. 4. This comment refers to the wording in the CDCA. It may be a valid point that this form of words could be ambiguous. However, its use is consistent with the other provisions in paragraph 12.2 (scheduling Meter reading visits) which concern onshore sites. This issue is therefore not specific to offshore sites and is not relevant to CP1324. If this form of words is considered to be an issue in relation to all sites (both onshore and offshore) it can be resolved via a separate CP.
Scottish and Southern Energy	Yes	**Role in which organisation is impacted:** Supplier and MOA **Impact:** Minor changes to training and procedures.	Yes	-
British Gas	Yes	-	No	-
British Energy	Neutral	**Would implementation in the proposed Release have an adverse impact on your organisation?** N/A **Associated costs:** N/A **Do you have any other comments?** Please see Q7 below *(i.e. redline text comments in table below)*.	No (Not currently)	-

Table 3: Comments on the redline text

No	Organisation	Document	Location	Severity	Comments	ELEXON Recommendation
1	British Energy	CoP1	3.7 5.5	H	It is not clear that the proposed definition of 'Communication Line' will meet the stated objective of minimising the risk of common mode failure. The use of separate PSTN (land line) telephone numbers will not necessarily guarantee this. They	ELEXON recommends no change should be made as we sought input from the expert group and none of them believed that a change was necessary – reasons are set out in detail in section 6, above.

					could still depend on the same line card in the same telephone exchange, connected to the site via the same cable, and wired locally through the same termination boxes and terminals. The loss or damage of any of these could still result in total loss of communications for data collection. Other options should be considered such as using different technologies for each line (e.g. PSTN and GSM), the use of private and public networks or the use of public network lines from separate telephone exchanges. To address these points it is suggested that the proposed definition be reconsidered.	
2	British Energy	CoP2	3.7 5.5	H	Comments as per Item 1 above.	ELEXON recommends no change should be made, as per response to comment 1, above.
3	British Energy	CoP3		M	It is noted that the requirement for separate communication links to each outstation has been confined to CoPs 1 and 2. This is acceptable providing there are no future offshore metering systems for circuits rated >10MVA. If this cannot be guaranteed it is suggested the proposed CoP 1 & 2 changes should also be made to CoP 3.	Comment noted. The Group believe the changes are appropriate for the current baseline. If different ratings of offshore circuits are introduced in future suitable arrangements should be considered at that time and introduced in a separate change, as appropriate. We believe it is highly unlikely an offshore installation of 132kV or above would be limited to a circuit capacity of less than 10MVA for economic reasons. If the voltage limit for the OFTO arrangements is lowered in the future then CoP3 may be impacted and we would seek to raise a CP to amend it.

Appendix 4 – Release Information

Key to Release Plan

Change Proposals and Modification Proposals in **BLACK** text represents SVA changes, **RED** text represents CVA changes and **BLUE** text represents changes which impact both the SVA and CVA arrangements.

The Authority decision dates are provided in the following format:	
P	Modification Proposal number
(< date)	Date by which a determination must be made by the Authority in order for the Modification Proposal to be implemented within the indicated release
Pro✓/Pro✗	Indicates that the Panel's recommendation to the Authority was to Approve/Reject the proposed Modification
Alt✓/Alt✗	Indicates that the Panel's recommendation to the Authority was to Approve/Reject the Alternative Modification

	February 2010 Scope (Imp. Date 25 Feb 10)	June 2010 Scope (Imp. Date 24 Jun 10)	Nov 2010 Scope (Imp. Date 5 Nov 10)
Change Proposals Pending		1322, 1323, 1324	1315
Approved	1295, 1296, 1297, 1298, 1299, 1301, 1302, 1303, 1304, 1306, 1307, 1308, 1310, 1311*, 1312, 1313, 1314, 1321	1309, 1311*, 1316, 1317, 1318	1267
Modifications Pending		P248 Pro✓, P249 Pro✓	
Approved	P246 Pro✓		P243 Alt✓, P244 Alt✓
Updates	P246 'Reporting of LDSOs of Aggregated Metering Data for Embedded Networks' was approved on 29 January 2010 with an implementation date of 31 March 2010. We will implement P246 as part of the February 10 Release. We will be raising an exception plan to include P246 in the scope of the Release and also to request demand led funds to implement the Modification. The scope of the Release now comprises of 1 Modification and 18 CPs. We hope to complete testing of the EAC/AA software on 8 February in preparation for the Programme Board go live decision on 10 February. We forecast to deliver the Release on schedule and within budget. We will implement all changes for the Release on 25 February 2010 with the exception of the CP1311 changes to BSCP504 which will become effective on 24 June 2010. P246 will become effective on 31 March 2010.	The scope of the June 2010 Release currently includes five approved CPs (1309, 1311, 1316, 1317 and 1318) which only impact Category 1 Code Subsidiary Documents. No changes to Central Systems are scheduled for this release. There are no Modifications currently approved for inclusion in this release. Modifications P248 and P249 are targeted for inclusion in the Release, subject to approval by the Authority.	P243 'Publication of Generator Forward Availability by Fuel Type' and P244 'Provision of BritNed Data to BMRS' were both approved on 21 January 2010 for inclusion in the November 2010 Release. The project is currently in the planning phase.

* Changes to BSCP504 as a result of the CP1311 solution will be implemented in the June 10 Release. All other changes resulting from CP1311 will be implemented in the February 10 Release.

Draft CP Scope of the February 2010 Release

CP	Title	Impacts	BSC Agent (Demand Led)	ELEXON Operational		Total
				Man Days	Cost	
CP1295	Process for distribution of MDD Updates not included in D0269/D0270 flows	BSCP505, BSCP508, SVA Data Catalogue Vol. 1 and Vol. 2	£6,000	20	£4,400	£10,400
CP1296	Mandatory Capability to Record Reactive Power Demand (kvar) Values in Code of Practice 5 (CoP5) Meters	BSCP601, CoP5	£0	2	£440	£440
CP1297	Mandatory Capability to Record Reactive Power Demand (kvar) Values in Code of Practice 10 (CoP10) Meters	BSCP601, CoP10	£0	2	£440	£440
CP1298	Requirement on MOAs to Configure Meters to Record Half Hourly Reactive Power Data (for Half Hourly Settled CT-Metered Customers)	BSCP514	£0	2	£440	£440
CP1299	Requirement on Half Hourly Data Collectors to Collect and Report Reactive Power Data (where the Meter is configured to record it)	BSCP502	£0	2	£440	£440
CP1301	Registration Requirements for System Connection Points between Onshore Distribution Systems and Offshore Transmission Systems	BSCP25, BSCP75, CRA URS	£700	4	£880	£1,580
CP1302	Requirement on Half Hourly Data Collectors to Validate Reactive Power Demand Values	BSCP502	£0	2	£440	£440
CP1303	Requirement on Half Hourly Data Collectors to Estimate Missing Reactive Power Demand Values	BSCP502	£0	2	£440	£440
CP1304	Exclusion of certain Site Visit Cehck Codes (SVCC) within the Long Term Vacant (LTV) site process	BSCP504	£0	1	£220	£220
CP1306	Removal of second criterion for identifying a site as Long Term Vacant (LTV)	BSCP504	£0	1	£220	£220
CP1307	Minor Changes to the Long Term Vacant Site Process	BSCP504	£0	1	£220	£220
CP1308	Changes to Long Term Vacant Site process where a reading is obtained via a warrant	BSCP504	£0	1	£220	£220
CP1310	Clarifications to Gross Volume Correction Process	BSCP504	£0	2.5	£550	£550
CP1311	Replacing Erroneous Forward Looking EACs	BSCP504	£18,700	55	£12,100	£30,800
CP1312	Use of Gross Volume Correction in Post Final Settlement Runs	BSCP504	£0	2.5	£600	£600
CP1313	Remove ELEXON from the Minimum Eligible Amount (MEA)	BSCP301, NETA Interface	£3,200	8	£1,800	£5,000

CP	Title	Impacts	BSC Agent (Demand Led)	ELEXON Operational		Total
				Man Days	Cost	
	request process	Definition and Design (IDD) Part 1, NETA Agent Interface Definition and Design (IDD) Part 2.				
CP1314	Housekeeping change to SAA Service Description	SAA Service Description	£0	0	£0	£0
CP1321	Housekeeping Change to correct a manifest error in BSCP301 and NETA IDD Part 2	BSCP301 and NETA IDD Part 2	£0	0	£0	£0
		Total[7]	**£28,600**	**108**	**£23,630**	**£52,450**

Draft CP Scope of the June 2010 Release

CP	Title	Impacts	BSC Agent (Demand Led)	ELEXON Operational		Total
				Man Days	Cost	
CP1309	Include reference to D0303 in BSCP514 and circumstances in which its use is mandatory.	BSCP514, SVA Data Catalogue Volume 1	£0	3	£660	£660
CP1316	Removal from BSCP536 of obligation to attach a copy of Form 536/01 to BSCCo Bill	BSCP536	£0	1	£220	£220
CP1317	Removal of Requirement for NHH MOAs to notify NHH DCs of metering work before the event	BSCP514	£0	1.25	£225	£225
CP1318	Minor changes to BSCP601	BSCP601	£0	1.75	£295	£295
		Total[8]	**£0**	**7**	**£1,400**	**£1,400**

[7] A Tolerance of 20% applies for both Demand Led costs and ELEXON Operational Costs
[8] A Tolerance of 20% applies for both Demand Led costs and ELEXON Operational Costs

SVG109/01 - Attachment A

CP1315 Assessment Report (Maintenance of Outstation Types as part of Compliance and protocol approval)

1 Summary

1.1 ELEXON raised CP1315 on 25 September 2009. We issued CP1315 for impact assessment (via CPC00669) in October 2009.

1.2 CP1315 aims to remove the Valid Set of Outstation Types from the DTC, and instead establish them as part of the Compliance and Protocol Approval process documented in BSCP601[1]. This compliments the DTC CP 'New Process for Managing Changes to Outstation Type Valid Set'.

1.3 We received 10 responses; of these 6 agreed, 2 disagreed and 2 were neutral.

1.4 We believe that the implementation of CP1315 would remove the existing delays in notifying parties of new Outstation Types which result in numerous workarounds and manual processes being employed to ensure the correct outstation types are defined. We therefore recommend, in light of majority industry support, that you:

- **APPROVE** CP1315 for implementation in the June 2010 Release.

2 Why Change?

2.1 Background

2.2 ELEXON raised CP1315 on 25 September 2009.

2.3 The CP1315 solution is based on CP1282. CP1282 was rejected by SVG, so that ELEXON could explore other (Market Domain Data) solutions. We did this via six options that we put forward in DCP0045. We selected this solution (option 1 in DCP0045) for progression to CP, with the support of the SVG realised the majority of respondents felt it to be simpler and more cost effective than the other solutions. Please refer to the DCP0045 next steps paper for more details.

2.4 The Problem

2.5 'Outstation Type' is a data item contained within the D0268 Half Hourly (HH) Meter Technical Details flow and is used by HH Meter Operators (MOs) and HH Data Collectors (DCs) to specify and determine which protocols must be used in order to dial into a particular Outstation. It is defined in the MRA Data Transfer Catalogue (DTC) as a three-character identifier, along with a Valid Set of available codes.

2.6 Outstation Types are not generic but rather act as references to specific Outstation makes and models, as in practice most metering communication protocols are manufacturer-specific. However, this means that if and when a new piece of equipment enters the market, it may not be properly represented by the Valid Set and so the HHDC may not be able to tell which protocol should be used, preventing them from dialling in to the Outstation.

2.7 At present, altering the Valid Set requires a formal change to the DTC, yet new equipment may be introduced at any time, outside the DTC release timescales. The result is that the Valid Set

[1] BSCP601 – 'Metering Protocol Approval and Compliance Testing'

will often be out of date, and participants will frequently have to resort to manual workarounds in order to transfer the necessary information.

2.8 The Current Situation

2.9 The current situation with the use of Outstation Types is that there are **15 Outstation Types** that have recently been approved for use in Settlement. All of which are in use but have no valid code in the DTC. In order to keep the Settlement process working, Supplier Agent hubs are adopting their own work arounds by agreeing the new Outstation Type codes. HHMOs and HHDCs communicate by e-mail consequently if there is no validation taking place. (Please refer to Appendix A for diagrams illustrate the CP1315 issue)

2.10 New Outstations are continuing to be approved and we expect a further **10 to 15 new types** over the next 6 months due to new smart meters coming onto the market. It has been suggested that introducing dummy codes into the valid set will eliminate the issues until new codes are introduced.

3 Solution

3.1 The Valid Set of Outstation Types should be removed from the DTC and instead be established as part of the Compliance and Protocol Approval process documented in BSCP601. Once an Outstation has passed protocol testing, an agreed Outstation Type would be established and included in a revised Approval List published on the BSC Website. (The prime source of information would still be the website but ELEXON would also send out notifications via Newscast. In addition participants could sign up to receive email updates via myELEXON directly.)

3.2 This information can then be used by HHMOs and HHDCs to configure their communication systems appropriately, so that they can receive the new codes in the D0268 flow. The draft redlining for BSCP601 is available in attachment A.

3.3 All existing Outstation Types would remain valid and would be transferred to the relevant entries in the Approval List. Attachment B to this CP provides an example, based on an extract from the current list, with additional columns to show the Equipment Type (i.e. Meter or Outstation) and Outstation Type.

4 Intended Benefits

4.1 The current arrangements prevent new equipment from being used properly in the market. The proposed approach will allow Outstation information to be kept more up to date and in so doing will make it easier for participants to make use of new equipment.

5 Industry Views

5.1 We issued CP1315 for impact assessment (via CPC00669) in October 2009. We received 10 responses; of these 6 agreed, 2 disagreed and 2 were neutral.

5.2 One respondent raised a concern that if the valid set of Outstation Types is removed from the DTC, this means that there is no DTC validation against Outstation Types.

5.3 We explained to them that, with the CP1315 solution, although there will be no DTC validation, participants can still have their own validation on their systems to prevent them sending/receiving invalid codes and thus we believed it would not cause major impact to metering outstation types.

The respondent still feels this CP will cause reduce the controls preventing input of invalid Outstation Types.

5.4 One respondent suggested adding a 'dummy code' or similar ID reference for any meter that has passed the protocol approval process but does not yet have an Outstation ID reference that is recognised by the DTC. This dummy ID would be included on the initial D0268, from which the associated Data Collector would know to refer to the Protocol Approvals list and assign an Outstation ID accordingly.

5.5 We don't believe this is the best approach to address the CP1315 issue and we would like to highlight that the DTC's valid set currently contains **8 'dummy codes'**, but all of these are in use. We also believe that creating more dummy codes will only serve to exacerbate the issues further.

5.6 We recognise that the solutions, if implemented, will mean some **system changes for participants**. However we believe the ongoing workarounds between HHMOs and HHDCs are not acceptable in the medium to long term. Further, we believe the current situation will deteriorate as more and more meters are being exchanged for smart meters and as new approvals are being made where the ability to keep the DTC in step with technical advancement will be difficult.

6 Impacts and Costs

Market Participant	Cost/Impact	Implementation time needed
ELEXON (Implementation)	Our implementation costs are 1 man days of effort (equating to approximately £240) to implement the necessary documentation changes.	June 2010 release suitable
HHDC	Process changes will be required for HHDC to implement the changes. Also occasional system updates will be required as new meter types arise.	June 2010 release suitable
MOP	Process changes will be required for MOP to implement the changes.	June 2010 release suitable
Supplier	System and process changes will be required for Supplier to implement the changes.	June 2010 release suitable

7 Implementation Approach

7.1 We recommend CP1315 to be implemented in June 2010 release since it is the next available release. All respondents feel that the implementation date is achievable.

8 Conclusion

The table below summarises the key arguments provided for and against the change:

Pros	Cons
• CP1315 would prevent the existing delays in notifying parties of new Outstation Types, which results in numerous workarounds and manual processes being employed to ensure the correct outstation types are defined; and • The proposed approach will enable Outstation information to be kept more up to date and in so doing will make it easier for participants.	• If the valid set of Outstation Types is removed from the DTC, this means that there is no DTC validation against Outstation Types. • The suggested inclusion of non-DTC-validated Outstation IDs within the D0268 will result in a mandatory system change.

9 Recommendation

9.1 We recommend, based on CP1315 would prevent the existing delays in notifying parties of new Outstation Types, which results in numerous workarounds and manual processes being employed to ensure the correct outstation types are defined; and majority industry support, that you:

- **APPROVE** CP1315 for implementation in the June 2010 Release.

Bu-Ke Qian

ELEXON Change Assessment

T:020 7380 4146

Table 1: Industry Impact Assessment Summary for CP1315 - Maintenance of Outstation Types as part of Compliance and protocol approval

IA History CPC number	CPC00669	Impacts	BSCP601

Organisation	Capacity in which Organisation operates in	Agree?	Days to Implement
Gemserv	MRASCo Ltd	Neutral	--
Independent Power Networks Limited	LDSO, UMSO, SMRA	Neutral	--
IMServ		Yes	30
Stark Software International Ltd	HHDC/HHDA/NHHDC/NHHDA/NHHDR	Yes	0
NPower Limited	Supplier, Supplier Agents	Yes	--
SAIC on behalf of: **ScottishPower Energy Management Ltd.** **ScottishPower Generation Ltd.** **ScottishPower Energy Retail Ltd.** **SP Manweb plc.** **SP Transmission Ltd.** **SP Distribution Ltd**	Supplier, LDSO, HHDA, NHHDA, HHDC, NHHDC, HHMOA, NHHMOA	Yes	0
British Energy Direct Limited	Supplier	No	120
Southern Electric Power Distribution; Keadby Generation Ltd; SSE Energy Supply Ltd; SSE Generation Ltd; and Scottish Hydro-Electric Power Distribution Ltd; Medway Power Ltd; SSE Metering Ltd;	Supplier/Generator/ Trader / Party Agent / Distributor	Yes	--
TMA Data Management	HHDC	Yes	--
E.ON UK Energy Services Limited	MOA	No	--

Table 2: Impact Assessment Responses[2]

Organisation	Agree?	Comments	Impacted?	ELEXON Response
Independent Power Networks Limited	Neutral	**Agree Change Comment:** IPNL would like to comment that a co-ordinated approach with the MRA will need to be taken (if approved) to ensure that the MRA is updated to sign post the changes in BSCP601.	No	Noted. We informed the respondent that a DTC CP 'New Process for managing Outstation Type Valid Set' will be raised once this CP is approved.
IMServ	Yes	**Agree change comment:** We agree with the change proposed. This will prevent the existing delays in notifying parties of new Outstation Types, which results in numerous workarounds and manual processes being employed to ensure the correct outstation types are defined. **Capacity in which Organisation is impacted:** HHDC/MOP **Impact on Organisation (e.g. systems/process changes):** Process changes **Adverse Impact?** No	Yes	--
Stark Software International Ltd Assessor Name: **Ed Sutton**	Yes	**Capacity in which Organisation is impacted:** HHDC **Impact on Organisation (e.g. systems/process changes):** Occasional system updates as new meter types arise. **Adverse impact?** No **Cost details**: £0 **Any other comments:** Please consider the use of the following codes or publish likely alternatives ASAP: ISKRA MT375 = IMT ISKRA MT423 = FMT EDMI Mk10 = EDM	Yes	We believe this comment provides a good example to demonstrate the necessity of this CP. As the suggestion indicated here, approved Outstation Types are already in use by HHDC, without any valid code in DTC. Also we are aware that different HHDCs use different Outstation Types before the DTC codes being published via DTC release, which causes considerable workaround between HHDCs and MOAs. We clarified to the respondent that if the CP is approved, we would need to communicate with

[2] Please note that we have only included responses in this table where the respondent provided additional information.

				those who use these codes (HHMOA & HHDCs) for a consensus view before they go live with them.
British Energy Direct Limited	No	British Energy have not agreed with CP1315 for the reasons highlighted below; **Systems** The suggested inclusion of non-DTC-validated Outstation IDs within the D0268 will result in a mandatory system change, to accommodate the various references that would be included as new metering types pass the protocol approval process. Since there will be multiple new references, all internal systems receiving D0268s will need to have all validation settings removed for this field, if MTDs are to continue to process successfully. This means that there will be no way for Supplier to proactively highlight "invalid" outstation types that are not recorded in the Protocol Approvals list. **Data Quality** As CP1315 proposes the removal of a DTC-recognised valid set as a part of the process, there would no longer be any regulation on what is included in the Outstation ID field. This could potentially cause an increased number of manual errors included in this field. If the associated Data Collector cannot determine the protocol due to incorrect entry of Outstation ID, this will result in an increased number of dial failures and D0001s raised, ultimately resulting in an increased level of estimated data being submitted into Settlement. If seen in significant numbers, this could ultimately affect Supplier performance and be detrimental to the	Yes	We had conversations with the respondent to get a better understanding of their concerns. <u>System change</u> We recognise that the solutions, if implemented, will mean some system changes for participants. However, we noted the current situation with the use of Outstation Types is that there are 15 Outstation Types that have recently been approved for use in Settlement. All of which are in use but have no valid code in the DTC. In order to keep the Settlement process working, Supplier Agent hubs are adopting their own work arounds by agreeing between them in terms of the new Outstation Type codes. We believe the CP1315 solution is a formalisation of such work arounds. Further, we highlighted to the respondent that the current situation would deteriorate as more and more meters are being exchanged for smart meters and as new approvals are being made where the ability to keep the DTC in step with technical advancement will become difficult. The respondent still has concerns around the DTC compliant system if this CP is implemented. <u>Data Quality</u> The respondent felt the manual intervention could cause an increased number of dial failures and could consequently impact their agents' ability to adhere to the appropriate PARMs serials. We noted the potential data quality issue raised by the respondent.

		agents' ability to adhere to the appropriate PARMs serials. We also have concerns about Proving Tests as the Meter Technical Details received may not contain the Outstation id that has been installed which puts the onus on manual investigation to determine what was installed. **TAA** This CP will have an effect on the ability of the TAA to assess compliance of these metering systems if outstation types are not held within the DTC. There will be no check that the TAA could perform against the validity of an outstation type against the D0268 received and therefore, ultimately, this could have the potential impact on settlement of a Cat 1 non-compliance that the TAA would be unable to identify. **Counter-Proposal** We suggest the following process for consideration; Current DTC-validated Outstation ID set would remain, with the addition of a "dummy" or similar ID reference for any meter that has passed the protocol approval process but does not yet have an Outstation ID reference that is recognised by the DTC. This dummy ID would be included on the initial D0268, from which the associated Data Collector would know to refer to the Protocol Approvals list and assign an Outstation ID accordingly. At the next possible DTC System Release, the approved Outstation ID would be added to the valid set list within the DTC. When this has taken place, there would be a mandatory		<u>TAA</u> We don't agree with issue raised regarding to the ability of the TAA to assess compliance of the metering systems. In our view, one action the TAA takes is to verify that the physical Outstation on site appears on our list of approved Outstations (not verification with the DTC entry). <u>Counter-Proposal</u> The respondent suggested that introducing dummy codes into the valid set will eliminate the issues until new codes are introduced. We highlighted to the respondent that it is worth noting that the DTC's valid set currently contains 8 'dummy' codes but all of these are in use. We believe that creating more dummy codes will only serve to exacerbate the issues further. We also believe the removal of all the existing dummy codes is one of the benefits this CP can bring to the industry.

		requirement on Meter Operators to re-send D0268 information with this now-validated Outstation ID included. This would ensure that the integrity of D0268 information within the market is not compromised. Having up-to-date information satisfies the original Justification for Change, as per CP1315. **Impact on Organisation's Systems and/or Processes?** Yes **Capacity in which Organisation is impacted)** Supplier **Impact on Organisation:** Systems and process changes **Implementation** 120 WD **Comments** Implementation of Systems and process changes **Would implementation in the proposed Release have an adverse impact?** Yes		
Southern Electric Power Distribution; Keadby Generation Ltd; SSE Energy Supply Ltd; SSE Generation Ltd; and Scottish Hydro-Electric Power Distribution Ltd; Medway Power Ltd; SSE	Yes	Amendments to process and procedures.	No	--

Metering Ltd;				
TMA Data Management	Yes	**Comments** CTMA support the change as we believe it offers the most flexible solution **Impact on Organisation's Systems and/or Processes?** Yes **Capacity in which Organisation is impacted** HHDC **Impact on Organisation** Systems / Procedures **Would implementation in the proposed Release have an adverse impact? (please state impact)** No	--	--
E.ON UK Energy Services Limited	No	**Comments**: We have significant Issues with this approach. If it is the intention to retain the concept of a valid set of outstation types (as would appear to be the case) then validation is required within the participants systems to ensure that only valid values are loaded into their systems. Whilst these valid values are held within the MDD system then there is an established mechanism for identifying and implementing changes. Under the proposed regime an parallel system will need to be establish to publicise and implement changes both internally and externally. In addition changes will be required to the data item definition within the DTC. **Impact on Organisation's Systems and/or Processes? Yes** **Capacity in which Organisation is impacted (e.g. Supplier, HHDC, etc) MOA** **Impact on Organisation (e.g.**	Yes	<u>Validation</u> We explained to the respondent that, with the CP1315 solution, although there will be no DTC validation, participants can still have their own validation on their systems to prevent them sending/receiving invalid codes and thus we believed it would not cause major impact to metering outstation types. The respondent still preferred the current mechanism of maintaining Valid Set as he believed changes via formal DTC release provide more assurance. <u>Communications</u> We explained to the respondent that the Valid Set of Outstation Types should be established as part of the Compliance and Protocol Approval process documented in BSCP601. Once an Outstation has passed protocol testing, an agreed Outstation Type would be established and included in a revised Approval List published on the BSC Website. (Participants should sign up myELEXON and tag the document 'CoP Compliance and Protocol Approvals

		systems/process changes) See Above		List' on ELEXON website, so that they will receive email updates via myELEXON directly whenever there is an update in the document.) Although SVG considered the above communication method to be the right way forward for DCP0045, the respondent remained unconvinced about the robustness of the communications. He suggested an alternative communication method which would require participants' positive confirmations to reflect the changes were acknowledged by the participants following ELEXON's notification.

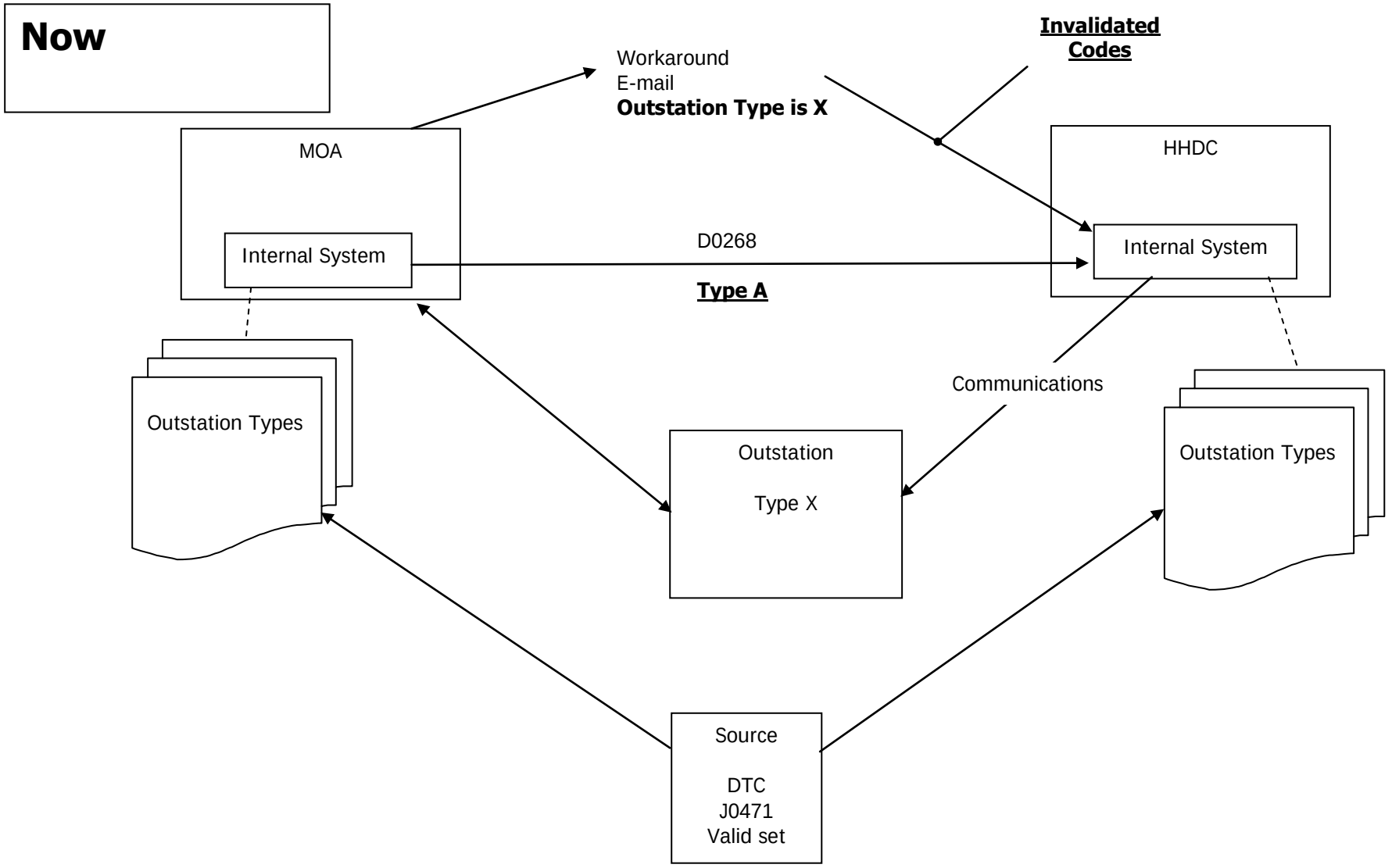
We didn't receive any comments on the redline text.

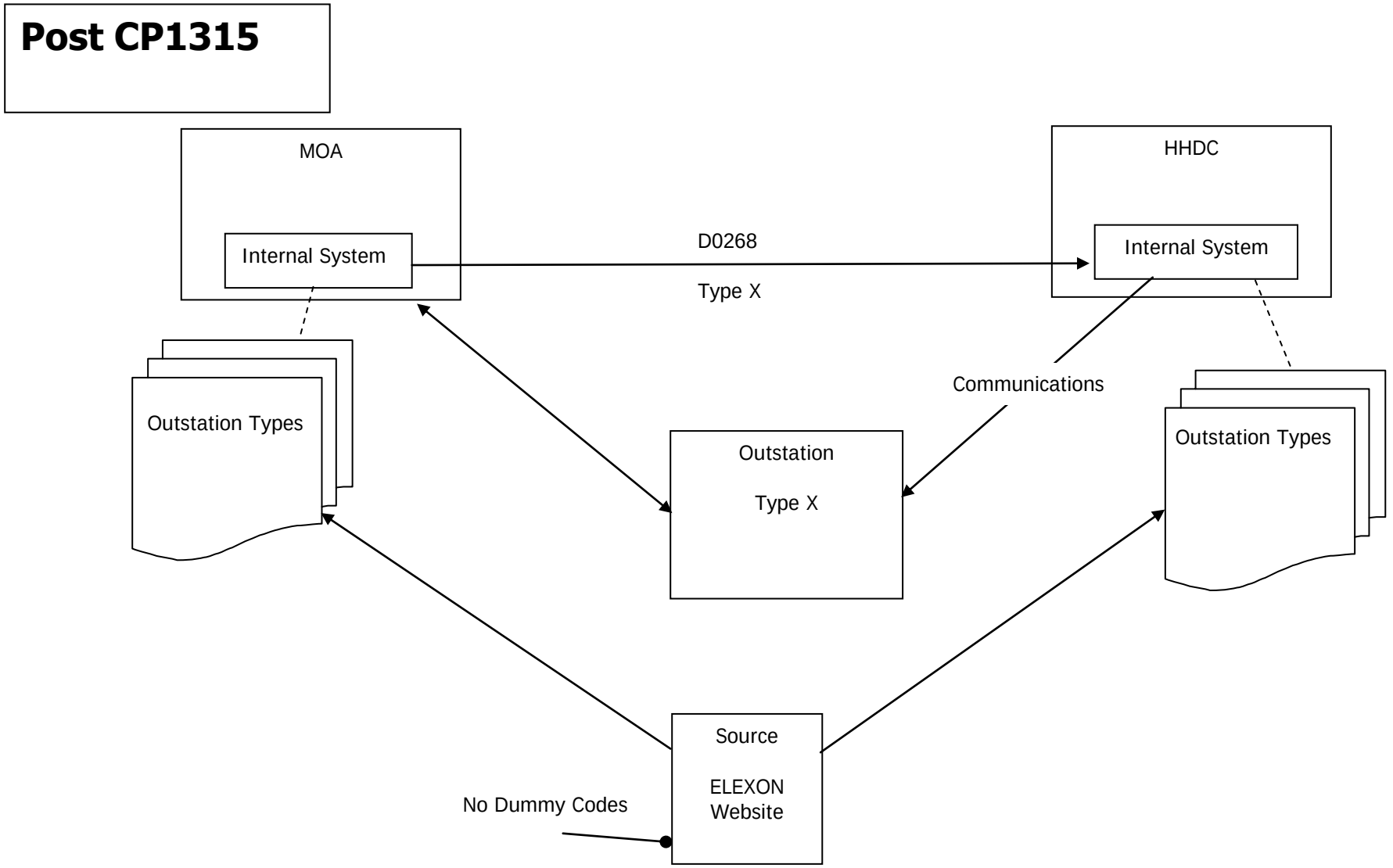
Appendix A – Current Workaround (between MOA and D) and CP1315 solution

In the following examples, Type X is an Outstation Type that has been approved for use in Settlement, but has no valid code in the DTC. (HHDC may not be able to tell which protocol should be used, therefore preventing them from dialling in to the Outstation has a valid code in the DTC)

Current situation - In order to keep the Settlement process working, Supplier Agent hubs are adopting their own work arounds by agreeing between them in terms of the new Outstation Type codes.

Post CP1315 - Participants will be notified by ELEXON (if they register on myELEXON) to update the valid set of Outstation type so that HHDC can dial in to the Outstation more efficiently.





Change Proposal (s)	New Process for Managing Changes to Outstation Type Valid Set
Synopsis of Change	ELEXON's proposal is to remove the current Outstation Type Valid Set from the DTC and instead replace it with a reference to a set of values contained in the Protocol and Compliance Approval List maintained by ELEXON. The data item itself would remain in the DTC and would retain the Logical Format of CHAR(3).

Do Not Support Solution	
British Energy Direct Limited	**Supplier**
Do Not Support	British Energy disagree with the content of the change proposal SPF0040 for a number of significant reasons. **Systems** The suggested removal of all existing Outstation Type valid set items will create significant impacts for various parties/ agents which British Energy do not believe have been adequately assessed prior to the generation of this solution form. By relaxing the DTC validation for this Item, agents could (through manual error, or similar) enter an Outstation Type that is not valid according to Elexon's Protocol and Compliance Approval List. As there are no valid set values in the DTC under the proposed solution, there is no way whatsoever of maintaining any control over the population of this Data Item, nor the highlighting of any invalid outstation types that are not recorded in the Protocol Approvals list. **Data Quality** If the associated Data Collector cannot determine the protocol due to incorrect entry of Outstation ID, this will result in an increased number of dial failures and D0001s raised, ultimately resulting in an increased level of estimated data being submitted into Settlement. If seen in significant numbers, this could ultimately affect Supplier performance and be detrimental to the agents' ability to adhere to the appropriate PARMs serials. We also have concerns about Proving Tests as the Meter Technical Details received may not contain the Outstation id that has been installed which puts the onus on manual investigation to determine what was installed. **TAA** The MRA solution (and associated Elexon Change Proposal) will also impact the TAA regards the assessment of compliance of these metering systems if outstation types are not held within the DTC. There will be no check that the TAA could perform against the validity of an outstation type against the D0268 received and therefore, ultimately, this could have the potential impact on settlement of a Cat 1 non-compliance that the TAA would be unable to identify **Additional Concerns** In none of the Change Proposals prior to this Pre-assessment has Elexon stipulated exactly *how* they are to maintain the Protocol and Compliance Approval List. This still remains a major concern to British Energy and

	should be carefully investigated before Gemserv seriously consider relaxing the rules of the DTC in the proposed manner. The proposed MRA solution needs to clarify further whether there are any additional changes to the Item (i.e. remains mandatory or becomes optional). It would also need to confirm whether there is any impact on existing D0268s where the Outstation Type is populated with a value from the current Valid Set. Since this information is not made explicit, Elexon and Gemserv should not expect agreement from the parties and agents to whom the pre-assessment has been sent.
E.ON UK Energy Services Ltd	**Interested Industry Participant**
Do Not Support	We feel that the proposed solution will make it much more onerous to ensure that the standing data within our systems is maintained. It is our belief that the lag time associated with waiting for a DTC update will inhibit the adoption of new outstations.
Support Solution	
EDF Energy	**Supplier / NHH Agent & HH MOP**
Support	Our main issue with this change remains how details of update are communicated to correct parties. We would still prefer a maintained email list of contacts where notification is sent. We note on SPF the statement "would be issued to interested parties and party agents", if this is via a maintained specific contact list then our issues on this change have been addressed.
ESP Electricity Limited	**Distributor**
Support	It is a similar process to the UMS Charge Code and Operation Information Document (OID) maintained by Elexon. These lists of approved codes and related information are kept up-to-date. It is a tried and tested approach.
Invensys – IMServ	**Interested Industry Participant**
Support	On the assumption that existing mechanisms for holding theses details can remain unchanged, there would appear to be no impact on systems only manual procedures. The solution is supported due to the faster turn-a-round time in handling new devices.
Electricity North West Limited	**Distributor**
Support	
Siemens Metering Services	**Interested Industry Participant**
Support	
RWE npower	**Supplier**
Support	Agree in Principle but would like the following issues clarified: The HHDC must still be informed of the Outstation Type, this will still occur through the MOP using J0471 in the D0268 - **This would be useful if this was verified & stated within the Solution Description**.

	Assuming the above is true, it would then be helpful if answers or at least acknowledgement of the following is referenced within the Solution Description: Q1 – how will the MOP be informed (by Elexon) of addition/removal/amendment to the list? Q2 – what assurance can Elexon provide that the message will be sent / received on time & by the correct organisations? Q3 – what validation will be performed by MOP to ensure the value they choose to insert into the D0268 is an Approved value? Q4 – what validation will be performed by HHDC to ensure that a value received in the D0268 is an Approved value?
ScottishPower Energy Retail	**Supplier**
Support	We see no issue with this change and are happy to accept it.
Neutral / Abstain	
GTC-UK	**Distributor**
Neutral / Abstain	
CE-Electric	**Distributor**
Neutral / Abstain	We support that this change would enhance the accuracy of the data held in the D0268. However we believe that this enhanced accuracy would be cancelled out by the fact that there would be no validation in place to ensure that the correct 3 digit code is applied. We believe that there needs to be some validation in place to ensure that accurate codes are entered in each instance.
SP Distribution Ltd / SP Manweb Plc	**Distributor**
Neutral / Abstain	SP Distribution Ltd / SP Manweb Plc believe that ELEXON has not provided enough evidence. For example, ELEXON have provided no evidence to support the statement: “The current arrangements prevent new equipment from being used properly in the market.” From our perspective the market appears to be working satisfactorily especially given that there have been no changes to the DTC since June 2000. If things go wrong, particularly on a CoS or CoA, spurious information could be entered leading to considerable problems and a site visit may be required to ascertain the outstation type to resolve. There is no apparent reason why ELEXON cannot raise a change via the DTC as and when the information is available i.e. after ELEXON approve its use.
No Interest	

CP1322 Attachment– CSD Architectural Principles Document v4.0 Redline Text v0.1

1 General

1.1 Purpose

1.1.1 This document sets out the principles that underpin the architecture of the Code Subsidiary Document (CSD) set. It sets out general principles concerning the contents of the CSDs along with more detailed guidance on the contents of each type of document. It also captures the principles governing the ~~modification~~ change ~~of~~ to existing and the creation of new CSDs.

1.1.2 All future changes to the CSD suite should be undertaken in a manner consistent with this ~~architectural~~ Architectural ~~principles~~ Principles ~~document~~Document.

1.2 NO CHANGES

1.3 Coverage of Code Subsidiary Documents

1.3.1 The constituent CSDs are defined in Section H1 of the Balancing and Settlement Code (BSC). They comprise:

(a) BSC Procedures;

(b) Codes of Practice;

(c) BSC Service Descriptions;

(d) The Party Service Line~~s~~;

(e) Data Catalogues;

(f) The Communication Requirements Document~~s~~; and

(g) The Reporting Catalogue.

1.3.2 An up-to-date list of the CSDs, indicating the version number of the then in force version[1] together with the date when it became effective is maintained by ~~ELEXON~~BSCCo. This is published as part of the BSC Baseline Statement.

1.4 Modification and Creation of Code Subsidiary Documents

1.4.1 Existing CSDs may be modified and new CSDs created in accordance with Section F3 of the BSC.

1.4.2 Such changes may only be made if and to the extent that the modified or new CSD:

(a) Is consistent with, and does not impair, or frustrate or invalidate, the provisions of the BSC; and

[1] Specific rules governing the Codes of Practice are specified in the Section L1 of the BSC.

(b) does not impose new obligations or restrictions of a material nature on Parties or Party Agents (or classes thereof) which are not authorised or envisaged by, or subsidiary to, the rights and obligations of Parties under, the BSC.

Where a Panel Committee considers that an obligation should be included within a CSD that is not reflective of an obligation within the BSC then the express approval of the BSC Panel shall be sought (which may necessitate raising a supporting Modification Proposal to the BSC).

1.4.3 When considering a proposed change to the CSD suite, the Panel or relevant Panel Committee shall additionally ensure that the BSC and CSDs together continue to facilitate the achievement of the Applicable BSC Objective(s), namely:

(a) The efficient discharge by the licensee [i.e. the Transmission Company] of the obligations imposed upon it by this licence [i.e. the Transmission Licence];

(b) The efficient, economic and co-ordinated operation of the national transmission system;

(c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity;

(d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements.

1.4.4 In particular where additional prescription is added to a CSD then the net effect of ~~the revised~~the revised suite of CSDs and BSC must be to better facilitate the Applicable BSC Objectives. Where this test is not achieved then the change should not be progressed.

1.4.5 Section F3 of the BSC requires that, prior to agreeing a change the following activities shall be undertaken:

(a) consultation shall take place with Parties and interested third parties in a manner appropriate to the complexity, importance and urgency of the proposed change;

(b) regard shall be given to any representations made during such consultation;

(c) the proposed draft changes shall be copied to each Party and otherwise published in such a manner as seen fit; and

(d) Parties and interested third parties shall be given a reasonable opportunity to comment on proposed changes, having regard to the urgency of the matter.

1.4.6 Detailed procedures relating to the processing of changes to the existing CSDs and the creation of new CSDs are set out in BSCP40.

1.4.7 The Panel has delegated its powers, functions and responsibilities to approve changes to the existing individual Code Subsidiary Documents to identified Panel Committees. The Baseline Statement records which Panel Committee discharges this for each CSD.

1.5 List of Acronyms

1.5.1 Other acronyms and defined terms take the meanings defined in the Balancing and Settlement Code (the Code), Section X.

Acronym / Term	Definition
BMRA	Balancing Mechanism Reporting Agent
BPM	Business Process Model
BSC	The Balancing and Settlement Code
The Code	The Balancing and Settlement Code
BSCP	Balancing and Settlement Code Procedure
CDCA	Central Data Collection Agent
CoP	Code of Practice
CRA	Central Registration Agent
CSD	Code Subsidiary Document
CVA	Central Volume Allocation
DTC	Data Transfer Catalogue
ECVAA	Energy Contract Volume Allocation Agent
FAA	Funds Administration Agent
GSP	Grid Supply Point
MRASCo	Master Registration ~~Agent~~ Agreement Service Company
~~NDFC~~	~~NETA Data File Catalogue~~
NETA	New Electricity Trading Arrangements
PSL	Party Service Line
SAA	Settlement Administration Agent
SVA	Supplier Volume Allocation
SVAA	Supplier Volume Allocation Agent
TAA	Technical Assurance Agent

2 General Structure of CSDs

2.1 NO CHANGES

2.2 Categories of Configurable Items

2.2.1 All BSC Configurable Items, of which CSDs form a subset, are either Category 1 or Category 2 Configurable Items, as defined in BSCP40.

2.2.2 Where a Change Proposal is raised that impacts the following types of Category 1 Configurable Items, redlined drafting of the proposed changes to the CSDs must be included with the Change Proposal:

(a) BSC Procedure (BSCP);

(b) Party Service Line (PSL);

(c) Code of Practice (CoP);

(d) Business Definition Document (including Data Catalogues, the Reporting Catalogue and the Communication Requirements Document); and

(e) Interface Design Document (IDD) (a Configurable Item but not a CSD – included for completeness).

2.2.3 When a Change Proposal does not impact Category 1 Configurable Items, the redlined changes required to support the solution need not be provided at the same time as the formal Change Proposal. All other Configurable Items, including the following types of CSDs, are known as Category 2 Configurable Items:

(a) BSC Service Description; and

(b) User Requirements Specification (a Configurable Item but not a CSD – included for completeness).

Other Category 2 Configurable Items exist which are outside the scope of this document.

3 Contents of ~~Specific~~ Category 1 CSD types

3.1 BSC Procedures (BSCPs)

3.1.1 Annex X-1 of the BSC defines a BSC Procedure as being "*a document of that title, as established or adopted and from time to time modified by the Panel in accordance with the Code, setting out procedures to be complied with (by Parties, Party Agents, BSC Agents, BSCCo, the Panel and others) in, and other matters relating to, the implementation of the Code*".

3.1.2 The BSCPs define the relationships, timescales and interactions between participants and specify the information or other outputs to be exchanged between them~~. They describe~~ as a step by step process~~, and can be divided into two broad categories as follows:~~. The BSCPs can contain guidance (e.g. guidance on how a section of a form should be completed) and may contain fields within forms to allow for the provision of optional (but not mandatory) supporting information. Where this is done it should be clearly marked as being guidance or optional respectively.

~~3.1.3 **Category 1 BSCPs: Interaction between BSC Parties, Party Agents and Central Settlement**~~

~~The first (and larger) category comprises those BSCPs which primarily describe the mechanisms used by BSC Parties (and their Agents) to communicate with central Settlement processes (e.g. BSCCo and BSC Agents). Examples of these include the Central Volume Allocation (CVA) BSCPs that describe the interaction of Parties and Agents with the Central Registration Agent, Central Data Collection Agent and other NETA services (e.g. BSCP15, 'BM Unit Registration'). These BSCPs are written to describe a functional process area and not limited to one particular participant's involvement in that process.~~

~~3.1.4 **Category 2 BSCPs: Interaction between BSC Parties and Party Agents**~~

~~The second category comprises those BSCPs which primarily describe the interactions between Party Agents and/or Parties (with central Settlement processes playing at most a secondary role). Examples of these include the Supplier Volume Allocation (SVA) BSCPs that describe the operation of the Supplier Hub (e.g. BSCP502, 'Half Hourly Data Collection for SVA Metering Systems Registered in SMRS'). These BSCPs are written to describe a process from the point of view of a particular Party Agent.~~

3.1.3 ~~Category 2~~A number of BSCPs detail the processes carried out by Party Agents. Party Agents are not bound to the BSC as they are not signatories to the BSC.~~-~~ The BSC places obligations on Suppliers which are fulfilled by their agents generally in accordance with these BSCPs. These BSCPs describe the requirements that the Party Agent's processes must meet in order to ensure that the BSC is correctly implemented, and should avoid prescribing the supporting processes required to implement those requirements. Where 'best practices' are identified then it would be appropriate to record this information in a separate guidance note.

~~3.1.6The BSCPs can contain guidance (e.g. guidance on how a section of a form should be completed) and may contain fields within forms to allow for the provision of optional (but not mandatory) supporting information. Where this is done it should be clearly marked as being guidance or optional respectively.~~

3.1.4 All ~~categories of~~ BSCPs should contain the following types of information:

(a) A statement to say which section of the Code the BSCP is derived from;

(b) Details of BSCPs which are referenced by the processes contained in this BSCP ('Related BSCPs');

~~(b)~~(c) The appropriate rules specifying how the information is to be provided;

~~(c)~~(d) The actual information to be produced;

~~(d)~~(e) The responsibilities for each process step;

~~(e)~~(f) Timescales for the delivery of information which are measurable;

~~(f)~~(g) Defined interfaces between participants;

~~(g)~~(h) The format of information (e.g. forms, flow references);

~~(h)~~(i) The Communications method;

~~(i)~~(j) The timescales for Communication; ~~and~~

(k) Guidance notes (that are clearly marked as such) where required;

(l) A short list of the overarching Code requirements for the particular Party Agent on the basis that Party Agents are not signatories to the Code (where appropriate); and

(m) Service Levels (where appropriate).~~.~~

The BSCPs should not contain workflow diagrams, with requirements being captured via interface and timetable tables.

~~3.1.8In addition to the above, Category 2 BSCPs should also contain the following types of information:~~

~~(a)A short list of the overarching Code Requirements for the Particular Party Agent on the basis that Party Agents are not signatories to the Code; and~~

~~(b)Service Levels (which have been transferred from the PSL).~~

3.2 Party Service Line~~s~~ (PSL~~s~~)

3.2.1 Annex X-1 of the BSC defines a Party Service Line as being "*a document of that title, as established or adopted and from time to time modified by the Panel in accordance with the Code, setting out the requirements as to particular services which are to be performed by Parties and Party Agents.*"

~~3.2.2Historically there are eight separate PSLs corresponding to the activities of the individual Supplier Agents. The documents capture both functional and non functional requirements.~~

~~3.2.3~~3.2.2 ~~This model will evolve with the creation of a~~There is currently a single Party Service Line ~~that~~ details the non functional requirements that are common to LDSOs and ~~all~~ SVA Party ~~agents~~Agents. This Party Service Line ~~shall~~ include~~s~~ the following generic requirements:

(a) audit requirements;

(b) data retention requirements;

(c) data quality requirements;

(d) security control requirements; and

(e) change control requirements.

3.3 Codes of Practice

3.3.1 Annex X-1 of the BSC defines a Code of Practice as being "a code of practice, as established or adopted and from time to time modified by the Panel in accordance with the Code, relating to Metering Equipment or any part or class thereof"

3.3.2 The Codes of Practice detail the technical requirements for Metering Systems. ~~Currently, there is a Code of Practice for all Half Hourly Metering Systems, Importing Non-Half Hourly Metering Systems and Importing and Exporting Non-Half Hourly Metering Systems.~~ Codes of Practice should contain the following information:

(a) Details of what should be measured and the accuracy of the energy measurements;

(b) The Metering Equipment Specification and the accuracy of each piece of Metering Equipment to be included in the Metering System; and

(c) The details of the defined Metering Points.

3.3.3 It should also be noted that the Codes of Practice versions are not time limited in the same way as other documents. Any Metering System is registered to a particular Code of Practice Issue number. If the Code of Practice is amended, the Metering Systems that are registered to that Code of Practice do not have to be amended in line with the changes to the Code of Practice, and Technical Assurance checks are carried out against the Code of Practice and Issue number applicable to a Metering System at the time of its first registration. This means that most Codes of Practice have several Issues which are still in use. This also includes some versions of Codes of Practice which were developed prior to the introduction of NETA (Codes of Practice A to K2). Updates to Codes of Practice~~,~~ can however only be base~~d~~ on the latest i~~I~~ssue of any particular Code of Practice. Codes of Practice have both i~~I~~ssue numbers and version numbers. If an update to a Code of Practice results in a material change to that Code of Practice, then the i~~I~~ssue number will be incremented along with the version number. If an update to a Code of Practice is minor ~~(i.e. the change to the Code of Practice will not result in any non-compliance being issued against a Metering System fitted to that Code of Practice Issue number)~~ then the version number will be incremented only. A minor change to a Code of Practice is a change such that existing Metering

Equipment/Metering Systems which are fully compliant with the previous version number should remain compliant with the subsequent version numbers of that issue in the Code of Practice.

~~3.4BSC Service Descriptions~~

~~3.4.1Annex X-1 of the BSC defines a BSC Service Description as being *"a document of that title, as established or adopted and from time to time modified by the Panel in accordance with the Code, setting out requirements as to particular services which are to be provided centrally as provided in Section E".*~~

~~3.4.2The BSC Service Descriptions describe the service to be provided by the BSC Agents. The BSC Agents currently are:~~

~~(a)The Balancing Mechanism Reporting Agent (BMRA);~~

~~(b)The Central Registration Agent (CRA);~~

~~(c)The Central Data Collection Agent (CDCA);~~

~~(d)The Energy Contract Volume Aggregation Agent (ECVAA);~~

~~(e)The Funds Administration Agent (FAA);~~

~~(f)The Settlement Administration Agent (SAA);~~

~~(g)The Supplier Volume Allocation Agent (SVAA);~~

~~(h)The Technical Assurance Agent (TAA);~~

~~(i)The Teleswitch Agent;~~

~~(j)The BSC Auditor; and~~

~~(k)The Profile Administrator.~~

~~3.4.3As a general rule, there is one BSC Service Description for each BSC Agent. The exceptions to this rule are the TAA Service Description and the SVAA Service Description. There are two TAA BSC Service Descriptions, one for SVA and one for CVA and the SVAA BSC Service Description is comprised of seven SVAA Service Lines. These documents form part of the contract with the BSC Agent.~~

~~3.4.4The obligations of the BSC Agent must be captured in the Service Description, whether by explicitly stating the obligation or by adding an umbrella statement and references to another appropriate CSD. The content of BSC Service Descriptions is set out in the Code, section E1.3. They should include (or include a reference to another document which includes) the following elements as the Panel decides to be appropriate:~~

~~(a)Specification of the services to be provided by the BSC Agent;~~

~~(b)Performance Levels for the BSC Agent;~~

~~(c)Amounts payable by the BSC Agent for the failure to meet the required levels of performance;~~

~~(d)The development and maintenance by the BSC Agents of a contingency plan;~~

~~(e)The provision by the BSC Agent of a disaster recovery service and the maintenance of a disaster recovery plan;~~

~~(f)The preparation of BSC Agent records;~~

~~(g)The provision to the BSC Auditor of access to any records that it requires;~~

~~(h)The provision by the BSC Agent of a help-desk service; and~~

~~(i)Specification of the services to be provided by the BSC Agent.~~

3.4 Data Catalogues

3.4.1 Annex X-1 of the BSC defines the Data Catalogue as "*having the meaning given to that term in Section O1.1.3.*"

3.4.2 The Data Catalogues are, for the SVA market, the SVA Data Catalogue and for the CVA market, the CVA Data Catalogue (supported by the ~~Logica~~ NETA Interface Definition and Design document (IDD) part 1 and the FAA IDD part 1~~ which are not CSDs~~).

3.4.3 The SVA Data Catalogue is similar to the Data Transfer Catalogue (DTC) which is owned by the Master Registration Agreement Service Company (MRASCo). The SVA Data Catalogue contains some of the Settlement related flows that are contained within the DTC as well as further manual instances of these flows and other manual flows.

3.4.4 The SVA Data Catalogue should not however repeat the DTC unless this is necessary for Settlement Purposes. Where duplication between the DTC and SVA Data Catalogue is necessary, the SVA Data Catalogue should be consistent with the DTC. Therefore where necessary duplication occurs between the SVA Data Catalogue and the DTC, changes to the SVA Data Catalogue may need to be reflected in the DTC and changes to a relevant flow in the DTC should be reflected in the SVA Data Catalogue.

3.4.5 The Data Catalogues should contain the details of the flows to be sent between participants and specifically contain the following:

(a) The data items to be included in the flow;

(b) The format of the flow, including headers and footers;

(c) Descriptions of the data items; and

(d) The format of the data items.

3.5 Communication~~s~~ Requirement~~s~~ Document~~s~~

~~3.6.1Annex X-1 of the BSC defines a Communications Requirements Document as "*having the meaning given to that term in Section 02.2.1 (b).*"~~

3.5.1 Section O2.2.1 (b) of the BSC defines a Communication Requirements Document as being "*a document or documents of that title, as established or adopted and from time to time modified by the Panel in accordance with the Code, containing detailed requirements for sending or receiving Communications between Parties and one or more BSC Agents using one or more than one Communications Medium(s)*".

3.5.2 The Communication~~s~~ Requirement~~s~~ Document relates to the sending and receiving of Communications between CVA Parties, CVA Party Agents, Market Index Data Providers and a

number of the BSC Agents. There is currently only one Communications Requirement Document which~~, mainly~~ exclusively relates to the CVA market (although reference is made to the Managed Data Network and applicable BSCPs as the equivalent in the SVA ~~Market~~market).

3.5.3 The content of a Communication~~s~~ Requirements Document is set out in Section O2.3 of the Code, ~~however~~ with the ~~details~~ requirements of the Communications themselves ~~are~~ contained within ~~a~~ the CVA Data Catalogue, which refers to the NETA IDD Part 1.

3.5.4 The Communication Requirements Document should include (or include a reference to another CSD which includes) the following elements:

(a) A description and specification of the Communications Medium;

(b) The specification of the systems required by a Party in order to send and receive Communications using the Communications Medium;

(c) Details of the tests that are required of a Party in relation to its Party System;

(d) Any particular requirements applying to a Party where it wishes to modify its Party Systems;

(e) Any security requirements applying in respect of the use of a Communications Medium by a Party;

(f) Any further terms applying to the use of a Communication Medium by a Party;

(g) The basis on which it will be determined whether and when Communications sent using the Communications Medium are deemed to have been received;

(h) The arrangements for the recording and logging and acknowledging the sending and receipt of Communications;

(i) The Time Standard applicable for the Communication; and

(j) Details relating to planned Agent downtime.

3.6 The Reporting Catalogue

3.6.1 Section V1.4 of the BSC defines the Reporting Catalogue as being *"the document of that title which sets out the data items to be contained in each of the reports mentioned in Annex V-1".*

~~3.7.1Annex X-1 of the BSC defines the Reporting Catalogue as being "the document referred to in Section V 1.4, as from time to time modified by the Panel in accordance with the Code"~~

3.6.2 There is only one Reporting Catalogue which covers both SVA and CVA reporting. It catalogues and provides further information on the content of reports issued by BSC Agents and BSCCo. It provides the details of what should be contained in the reports set out in Section V, annex V1 of the Code. It should also include the provisions of other related reports such as Performance Reports and Exception Reports. It should not however cover reports that can be found in the Data Catalogues. The Reporting Catalogue should not duplicate information that is contained in a Data Catalogue or the Interface Definition & Design Documents.

4 Contents of Category 2 CSD types

4.1 BSC Service Descriptions

4.1.1 Annex X-1 of the BSC defines a BSC Service Description as being "*a document of that title, as established or adopted and from time to time modified by the Panel in accordance with the Code, setting out requirements as to particular services which are to be provided centrally as provided in Section E*".

4.1.2 The BSC Service Descriptions describe the service to be provided by the BSC Agents. As a general rule, there is one BSC Service Description for each BSC Agent. The exception to this rule is for the TAA, for which there are two TAA BSC Service Descriptions, one for SVA and one for CVA. These documents form part of the contract with the BSC Agent.

4.1.3 The obligations of the BSC Agent must be captured in the Service Description, whether by explicitly stating the obligation or by adding an umbrella statement and references to another appropriate CSD. The content of BSC Service Descriptions is set out in the Code, section E1.3. They should include (or include a reference to another document which includes) the following elements as the Panel decides to be appropriate:

(a) Specification of the services to be provided by the BSC Agent;

(b) The development and maintenance by the BSC Agents of a contingency plan;

(c) The provision by the BSC Agent of a disaster recovery service and the maintenance of a disaster recovery plan;

(d) The preparation of BSC Agent records;

(e) The provision to the BSC Auditor of access to any records that it requires; and

(f) Specification of the services to be provided by the BSC Agent.

~~3.1.6~~

CP1323 – BSCP537 Appendix 1 v7.0 Redline Text v1.0

Guidance for completing the SAD

Qualification process

The SAD embodies the requirements for both Qualification and re-Qualification. Applicants are required to complete the SAD in accordance with BSCP537 'Qualification' and Section J of the BSC. References and abbreviations used in the SAD are based on BSC definitions, where this is not possible further guidance has been provided in BSCP537 section 1.5 List of Definitions. BSC documents referred to within this SAD are available on the BSC website (www.ELEXON.co.uk) and in all cases the most recent versions should be applied.

Section J of the BSC and BSCP537 explain that the Qualification process will be based on self assessment by Applicants, with limited follow up work to be undertaken by BSCCo rather than an audit of the system development being undertaken. BSCCo, through limited risk based review and, where required, follow up visits, will determine whether an Applicant's responses to the questions within the SAD adequately support their self assessment conclusions as to whether they have met the Qualification Requirements.

The Qualification process is not designed to identify whether the Applicant will be in full compliance with all of the requirements in the BSC and the Code Subsidiary Documents. The aim is to reduce the risk to Settlement that may be introduced as a result of a new Qualified Person entering the market. The process is designed to indicate whether, in certain key areas identified as high risk, an appropriate standard has been achieved.

The full set of requirements to which the Applicant must adhere on entry and on an ongoing basis is as set out in the BSC and the Code Subsidiary Documents. The guidance provided in this SAD should not be deemed as a comprehensive interpretation of those requirements.

RRe-Qualification process

Qualified Party Agents may identify a need to apply for re-Qualification of their Agency Service. This process is required when there is a Material Change to the functionality of a Party Agent's systems or processes used for the delivery of that service. Examples of possible re-Qualification triggers are outlined in BSCP537. The agent is required to determine which SAD questions should be re-addressed and these questions should be completed afresh in order to reflect the changes to be implemented. Section 1 (Introduction) should be completed in all cases, with particular reference to Section 1.3.

Throughout the SAD the term 'service' is used to describe the systems and processes that an Applicant will utilise to fulfil its obligations as a Qualified Person. When answering questions you should consider all aspects of your service that are relevant and that you intend to use in order to fulfil that requirement.

Guidance for completing the SAD (continued)

Completing the SAD

The SAD is split into 18 sections. Sections 1 to 7 are generic and should be responded to in full in respect of all Qualification applications. The remaining sections relate to specific services, Applicants should address these as relevant to their application. Each section contains a series of questions, for each of which guidance is provided in order to either provide clarification or to set out the areas the response should address.

When completing the SAD, Applicants should provide sufficient detail for the reader (which could be, for example, the director reviewing the responses prior to sign off, or BSCCo) to be able to evaluate whether the requirements have been addressed without requiring the reader to examine the supporting documentation or to perform additional enquiries. Responses should document not only the activities undertaken to address the requirements but should also document the control procedures, such as authorisation, review or testing processes, which have been performed in order for the Applicant to have assured themselves that the requirements have been met in a satisfactory manner. The responses to questions will depend on the size of the Applicant and the sophistication of the systems involved.

The Applicant should also indicate what evidence is available to support the responses given. This evidence will need to be available to BSCCo should any review take place. This evidence should not be attached to the return but a cross reference to the material should be included in the SAD.

References to 'systems' within the SAD do not relate solely to the functionality of computer hardware and software, but extend to the supporting business and operational processes (including manual processes). The term 'development' in relation to a system refers to either the development of a new system or to any significant changes or upgrades in respect of a previously Qualified system.

For the purposes of responding to this and other sections of the SAD, a 'Simple' service is one that is largely paper based, although simple spreadsheets or databases may be used for recording information and email may be used for some communication. Other more sophisticated services are 'Complex'. A number of the sections in this SAD include specific questions for either Complex or Simple services.

A number of the questions may require the Applicant to seek assistance from a third party developer, where that third party has developed all or part of the service, in order to provide a response. However, in all cases the responses are the responsibility of the Applicant. There may be an overlap in responses given and the Applicant should consider the most appropriate way to co-ordinate their own responses with those of the third party provider.

Suppliers after successfully completing Qualification will Qualify as either a HH Supplier or a NHH Supplier. If a HH Supplier wishes to then operate as a NHH Supplier or vice versa they would then have to complete the Qualification Process (not the re-Qualification process) to act in that different capacity.

Additional guidance on the completion of the SAD can be found in Appendix 3 of BSCP537 and further guidance on the Qualification and re-Qualification processes are can be found in the Overview of Qualification document.

Director Sign off page

NAME OF APPLICANT:

Qualified Person:

Except for the matters detailed below (delete if not applicable), having made appropriate enquiries of other directors and officials of the organisation, we confirm that:

- **the BSC Qualification Documentation (SAD) in respect of the above service is true, complete and accurate and not misleading because of any omission or ambiguity or for any other reason; and**
- **in our opinion, the arrangements as documented are adequate and appropriate for that service.**

Please detail any exception here:

Approved by

_____	_____	_____	_____
Print Name	**Signature**	**Position**	**Date**

Note: The SAD should ~~be authorised~~be authorised by a registered Director of the company (verifiable with Companies House~~) for~~) for and on behalf of their company in respect of Qualification issues.

SECTION 1 – INTRODUCTION

Objectives of this section

This section is designed to gather factual information about the Applicant and the service that they have applied to operate.

Guidance for completing this section

This section has been split as follows:

1.1 Generic Section (to be completed in all cases).

1.2 Re-~~-~~ Qualification Application Section (to be completed by those Applicants applying for Re-~~-~~Qualification).

1.3 Additional Information

~~1.3 Re-Qualification Application Section (to be completed by those Applicants applying for re-Qualification).~~

The final question, in this and every section, is not mandatory and is provided so that Applicants can provide any additional information that they consider to be relevant to their application.

For Supplier Qualification please state clearly which market you wish to operate in: Non Half Hourly, Half Hourly or both. Applicants who are currently operating in a market and who wish to Qualify for the other market will have to Qualify again for the second market they wish to operate in.

1.1 Generic Section

Question	Guidance	Response	Evidence
1.1.1 What is the name of the organisation applying to	The company name should be the statutory entity applying for Qualification (or re-Qualification), as		

Question	Guidance	Response		Evidence
become a Qualified Person?	registered with Companies House.			
1.1.2 What is the company number of the organisation applying to become a Qualified Person?	The company number refers to the registered company number.			
1.1.3 What is (are) the MPID(s) that will be associated with this service?	The process for registering an MPID in MDD is given in BSCP509.			
1.1.4 What service is this application for?	Please tick the appropriate box(s). Descriptions of the service are in BSC Section S.	Qualification	Re-Qualification	
		NHHDA □ NHHDC □ HHDA □ HHDC □ SMRA □ SVA HHMOA □ SVA NHHMOA □ CVA MOA □ Meter Administrator □ ~~Supplier –~~ NHH Supplier □ HH Supplier □ UMSO □	NHHDA □ NHHDC □ HHDA □ HHDC □ SMRA □ SVA HHMOA □ SVA NHHMOA □ CVA MOA □ Meter Administrator □ UMSO □	

Question	Guidance	Response	Evidence
1.1.5 What are the contact details for this application?	A key contact will act as the central point of communication for BSCCo in relation to this application.	Key contact name: Address: Email address: Telephone number: Fax number:	
1.1.6 Who are ~~the authorised~~the ~~signatories~~authorised signatories for the service(s) for Qualification matters?	Qualification-related documentation should be authorised by a registered Director of the company (verifiable with Companies House), for and on behalf of their company in respect of Qualification issues. A sign off sheet has been provided for this purpose (page 4).		
1.1.7 What is the background to this application?	Include details of the trigger for this application and a description of the service to be operated.		
1.1.8 Is the service that you intend to operate Complex or Simple?	Please tick the appropriate box and provide an explanation as to why you have reached the conclusion made. Complex indicates applicant has IT based systems and processes. Simple indicates applicant has Manual based systems	Complex ☐ Simple ☐	

Question	Guidance	Response	Evidence
	and processes		
1.1.9 What is the background to this application?	Provide a simple description or diagram as to how your service will operate and how elements of the service fit together. Include a description of IT systems that are to be used in the operation of this service. Specify where any of the software used has been centrally developed (e.g. the NHHDA software) or is commonly used by other participants within the industry.		
1.1.10 What is your intended scale of operation?	This is the volume of MSIDs at which you expect to operate in the market. This should correlate to the level of testing which has been performed. This will provide guidance as to the extent of the operation and the relative risk to Settlement. Guidance on volume and performance testing is provided in the SAD Additional Guidance document.		
1.1.11 Has the system that you intend to operate been developed internally or have you relied on a third party provider?	Please tick the appropriate box and enter the names of any third party developers. Please provide a brief description of the role of each third party developer. A number of the sections in this SAD include additional questions that should be completed where	Internally developed □ Third party developer □	

Question	Guidance	Response	Evidence
	the Applicant has relied on a third party provider for system development. Please also provide details of the software/applications you intend to use to operate the services if not already included in your response to 1.1.9.		
1.1.-12 Do you intend to rely on any subcontractors or service providers during the operation of the service and how do you intend to manage the relationship(s)?	Enter all subcontractors or service providers that you intend to rely on in operating the service once Qualified. Please provide a brief description of the role of each subcontractor or service provider in operating the service on an ongoing basis.		
1.1.-13 Are you currently a Qualified Person?	If any other services are currently provided by your organisation, please provide details of the type, Market Participant ID and number of MSIDs currently managed. Also indicate whether the current services are operated as a 'Complex' or a 'Simple' service.		

1.2 Re-Qualification Application Section

Question	Guidance	Response	Evidence
1.2.1 What is the nature of the Material Change to systems and processes which has triggered r~~R~~e-Qualification?	Please give a description of the reason for the application for re-Qualification. Further guidance for re-Qualification triggers is provided in BSCP537 section 3.4		
1.2.2 What questions/sections of the SAD do you propose completing in respect of this application?	Enter a list of all questions that are to be revised in respect of this re-Qualification application.		
1.2.3 For any outstanding BSC Audit issues please provide details of your rectification plans.	Please provide an audit issue reference and a description of the rectification plan you have in place.		

1.3 ~~1.3~~ Additional information

This section is not mandatory but is provided so the applicant can provide any additional information that they consider to be relevant to their application

Question	Guidance	Response	Evidence
1.3.1 What additional detail would you like to add to your response?	The Applicant can use the space provided to add any additional clarification and/or evidence that they consider necessary. This question is optional.		

SECTION 2 – PROJECT MANAGEMENT

Objectives of this section

To ensure that the Applicant has managed the delivery/implementation of the service in a controlled manner so as to minimise any adverse risk to Settlement, including the impact on other Market Participants.

Guidance for completing this section

It is expected that regardless of the size of the Applicant's organisation and/or complexity of the development that a level of senior management control would be exercised over the project to ensure that what is delivered by the project meets the organisation's requirements as well as those of the BSC.

A number of the other sections within the SAD address specific aspects/tasks that the project would undertake, e.g. testing and data migration. This section is aimed at the management control processes that are in place over the entire project, and all of its constituent parts. The section has been split as follows:

2.1 Complex Service Section (to be completed for Complex services only)~~.~~ (IT-based processes).

2.2 Simple Service Section (to be completed for Simple services only)~~.~~ (manual processes).

2.3 Additional questions for a system developed by a third party (to be completed in addition where the Applicant has relied upon a third party for all or part of their system development).

The questions in subsection 2.3 may require the Applicant to seek assistance from the third party in order to provide a response, however in all cases the responses are the responsibility of the Applicant. There may be an overlap in responses given and the Applicant should consider the most appropriate way to co-ordinate their own responses with those of the third party provider.

2.1-2.4 NO CHANGES

SECTION 3 – TESTING

Objectives of this section

To ensure that the testing carried out by the Applicant can be relied upon to check that additional risk does not enter Settlement and that current and future Market Participants are not adversely impacted. To provide assurance that the testing plans and procedures followed (in respect of IT and/or manual processes) are of sufficient rigour to ensure that these risks are adequately addressed.

Guidance for completing this section

The Applicant should be able to demonstrate that they have a comprehensive, documented approach to testing of the systems being developed that is appropriate for the complexity of the system.

In completing the response the Applicant will need to demonstrate that they have satisfied themselves that the BSC requirements have been met and that the Applicant can demonstrate that they understand and can execute all business processes in the defined timescales. Testing should be designed to thoroughly test systems, manual processes, operational staff and local working procedures.

The section has been split as follows:

3.1 Complex Service Section (to be completed for Complex services only);

3.2 Simple Service Section (to be completed for Simple services only); and

3.3 Additional questions for a system developed by a third party (to be completed in addition where the Applicant has relied upon a third party for all or part of their system development)

The questions in subsection 3.3 may require the Applicant to seek assistance from the third party in order to provide a response; however, in all cases the responses are the responsibility of the Applicant. There may be an overlap in responses given and the Applicant should consider the most appropriate way to co-ordinate their own responses with those of the third party provider.

3.1 Complex Service Section

Question	Guidance	Response	Evidence
3.1.1 How have you developed and implemented your test strategy and/or plans to demonstrate that you are able to operate the service?	The response should address the following areas: 1. A clear approach to testing should be documented. P~~p~~lease provide a brief description of your overall approach to testing. 2. Responsibilities for each element of the plans should be defined and assigned. 3. Any risks associated with the plans should be documented and a risk analysis should have been performed. Where any risks identified are to be mitigated by testing this should be made clear. 4. Success or acceptance criteria should be defined for each stage of testing activity together with an explanation as to how these will be measured. 5. A policy for the performance of regression testing should be set out (when individual parts of the system fail their test requirements then any link between these and the rest of the system should be re-tested - (this is optional for Simple systems).		
3.1.2 How have you demonstrated that these plans have been formally approved?	A project board and/or sponsor and/or senior member of the organisation should have approved all aspects of the test planning and documentation (including where relevant test strategy, test criteria, test		

Question	Guidance	Response	Evidence
	specification and data and test schedules) prior to testing taking place. Evidence of the sign off of key documentation should be made available.		
3.1.3 How have you determined the extent and coverage of testing that you intend to perform?	The extent and coverage of testing should be set out together with an explanation as to how this has been determined.		
3.1.4 What types of testing have you performed to ensure that all aspects of your service have been tested appropriately?	Refer to Appendix 2 for additional information on the requirements for certain aspects of testing. Examples of business processes that require testing are referenced in the service specific sections. Please note whether or not your testing covers each of the following areas and describe the level of testing carried out in each area: 1. Unit testing. 2. System testing. 3. Factory testing. 4. Integration testing. 5. Interface testing between the Applicant and other participants that you might reasonably be expected to interact with.		

Question	Guidance	Response	Evidence
	6. BSC Compliance (a documented link/audit trail between the BSC requirements identified as relevant to the operation of the service and the testing performed should be maintained, it is anticipated that this will be demonstrated by some form of mapping document showing each requirement and linking this to the system specifications or local working procedures with evidence as to how each has been tested). This is considered to be a key requirement of the Qualification process. 7. Performance, resilience and capacity testing (including a description as to how testing has demonstrated that the service will be able to perform at the level of activity predicted by your intended maximum scale of operations as detailed in Section 1). 8. Regression testing. 9. Disaster Recovery testing (to avoid repetition within the SAD, Disaster Recovery planning and testing has been covered as one topic in Section 4. Please provide a cross reference to your response in that section). 10. Business processes or user acceptance testing (a formal acceptance of the systems by the users is		

Question	Guidance	Response	Evidence
	considered to be a key criteria for Qualification). 11. Testing of local working procedures (local working procedures should provide the link between the requirements that have to be complied with and the practical reality of operating the service). 12. Any other types of testing that may have been performed. For Applications that will include a migration of data from one system to another, section 7 sets out the requirements for data cleansing, migration strategy planning and migration testing.		
3.1.5 How have you monitored the progress and results of testing at each stage?	The response should address the following areas: 1. A formal record should be maintained of the progress of each of the testing activities planned in the test strategy or plans, including a record of actual test results against expected test results in order to determine whether testing is complete. 2. A formal record should be maintained of each fault, problem or issue encountered during the testing process. Each fault, problem or issue should be given a severity and priority for resolution and tracked to closure/resolution.		

Question	Guidance	Response	Evidence
	Evidence should be retained that failed scripts have been followed up and problems resolved. 3. A formal assessment should be performed at the end of each stage of the testing process in order to determine whether all testing activities are complete.		
3.1.6 How have you ensured that all high severity faults, problems and issues identified have been addressed and do you have a plan in place to address any non-high severity faults, which you consider can be addressed at a later stage?	The response should address the following areas: Reports should be produced on all outstanding faults and issues identifying for each the nature of the fault, severity, steps to be taken to resolve the fault and impact on the organisation's ability to operate the service. Evidence to support the response to this question is expected to include an issue log/report.		

Question	Guidance	Response	Evidence
3.1.7 How are you able to demonstrate that all planned testing has been completed?	Evidence of completion is expected to include a test completion report. Where planned testing has not been completed an explanation as to why this has been the case should be provided within the supporting evidence. It is anticipated that all high severity faults will have been cleared and this should be confirmed within any test completion report provided.		

3.2-3.4 NO CHANGES

SECTIONS 4-7 – NO CHANGES

SECTION 8 – NHHDC

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your Agency Service to ensure the operational requirements of the BSC, BSCP504 and PSL100 are met. Whilst Sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a NHHDC agent.

Guidance for completing this section

The NHHDC agent collects and processes Meter readings and performs the calculation of Estimated Annual Consumption (EAC) and Annualised Advance (AA) values. Settlement of Non Half Hourly Metering Systems is performed on the basis of profiled EAC and AA values for onward submission to the NHHDA agent. The section is split as follows:

Business Processes and Mitigating Controls: This set of questions looks at the controls over the input of Meter readings to the NHHDC system, the subsequent creation of EAC and AA values and the transmission of these to the NHHDA agent. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement), the provisions for a full audit trail history of the data used by your Agency Service, and any changes made to it as outlined in BSCP504 and PSL100.

Exception Management: The section looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. This section of the SAD is concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the Agency Service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means (e.g. email, fax letter).

8.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
8.1.1 How do you ensure that data flows are received and processed completely, accurately and in a timely manner, in line with the requirements of BSCP504 and PSL100?	The NHHDC agent receives a number of key inputs, including the following: 1. Appointment and termination notifications on D0155 and D0151 data flows (including read frequency requests) from Supplier (BSCP504 3.2, 3.3 & 3.4). 2. Metering System Settlement detail affirmations on a D0052 data flow (including D0052 received for Unmetered Supply Metering Systems) from Suppliers (BSCP504 3.2 & 3.3). 3. Notification of mapping details and Non Half Hourly Meter Technical Details on D0149 and D0150 data flows from Meter Operator Agents (BSCP504 3.2 & 3.3). 4. Confirmation or rejection of energisation status change on a D0139 data flow from Meter Operator Agents (BSCP504 3.3.3, 3.3.4, 3.3.5). 5. Notification of change to other Parties from Suppliers on a D0148 data flow (BSCP504 3.2, 3.3 & 3.4). 6. Market Domain Data on D0269 and D0270 data flows and Daily Profile Coefficients on a D0039		

Question	Guidance	Response	Evidence
	file from SVAA. (BSCP504 3.1). The response should address the following areas: (a) The identification, review and authorisation of all flows prior to processing. (b) Controls in place to ensure that all data required or expected is received. This may be through controls within the update routines or through manual controls. (c) The validation of data for formats and lengths, e.g. the MSID is valid. (d) The validation of standing data received against the latest version of MDD, data items and combinations such as Profile Class, Standard Settlement Configuration, Data Aggregator ID, Data Collector ID, Meter Operator Agent ID, Supplier ID, GSP Group or energisation status. (e) The validation of data for its internal consistency. (f) The controls over the completeness and accuracy of MDD in line with the go-live dates as published in the MDD circulars, including controls to ensure that where MDD items are selectively applied to the database, that the appropriate items are selected and that all are		

Question	Guidance	Response	Evidence
	applied completely and accurately. Please specify whether this process will require manual intervention.		
8.1.2 How do you ensure that Meter reads are scheduled in line with BSCP504 and PSL100?	Please provide a response for all types of Metering Systems for which you operate as NHHDC, e.g. standard cyclic Metering Systems, remote pre-payment Metering Systems, de-energised Metering Systems, Automated Metering Systems, etc.		
8.1.3 Where your retrieval system is separate from your data processing system, what controls do you have in place to ensure that Meter readings collected by one system are transferred completely and accurately to the other?	This question is only relevant to Agents operating separate data retrieval and data processing systems. Where this is not relevant please state "not applicable".		
8.1.4 How do you ensure that all appropriate Meter readings are collected, to satisfy BSCP504 and PSL100?	The response should address the following areas: 1. The controls in place to ensure the completeness of Meter read collection and upload onto the system. This should include both manual and electronic Meter reads including the following read types:		

Question	Guidance	Response	Evidence
	(a) Hand held unit. (b) D0010 – from Supplier or Meter Operator Agent. (c) Other electronic files. (d) Interactive voice recognition system. (e) Operator phone conversation. (f) Read sheet or read card. (g) Automated Meter Readings. 2. When visiting a site or remotely contacting a site the checks are performed as detailed in BSCP504 Appendix 4.1. 3. The processes to ensure that any consumption for Metering Systems recorded as de-energised on your Agency Service is identified and processed to Settlement. 4 The controls in place to check that all scheduled reads have been performed.		
8.1.5 How do you ensure that Meter readings are validated to satisfy BSCP504 and PSL100?	The response should address the type and level of validation undertaken against each of the read types, including those defined in question 8.1.4 above.		

Question	Guidance	Response	Evidence
	The minimum validation requirements for Meter readings are set out in BSCP504 Appendix 4.2. The response should specify where the validation is performed (may be split between different parts of the system). Controls should be in place to ensure that the validation is performed on all Meter read types – reads may be input by different methods. (Question 8.2.1 relates to how you would deal with reads that have failed validation)		
8.1.6 What controls do you have in place to ensure that Meter reads are only withdrawn in the circumstances given in BSCP504 3.3.8?	The response should address the following areas: 1. The controls in place to identify circumstances in which a read withdrawal is required (either internally or as a result of an external instruction). 2. The controls in place to ensure the accuracy of the read withdrawal and application of roll back procedures. 3. The controls in place to ensure that the corrected consumption for a Metering System is calculated and then passed to NHHDA.		

Question	Guidance	Response	Evidence
8.1.7 What controls do you have in place to ensure that a correct EAC/AA is calculated on receipt of consumption data as per the BSC Section S Annex 2 4.3?	The response should address the controls in place to ensure that all appropriate data is passed to, and from, the EAC/AA system and the NHHDC system, which may include: 1. Validation of input/output files, e.g. by control totals, checksums. 2. Procedures to re-submit data that has failed validation. 3. Controls in place to ensure the complete receipt of downloads, e.g. a one to one matching process or file sequencing.		
8.1.8 Where it is necessary for your Agency Service to deem a read to meet the requirements of the BSC, BSCP504 and PSL100 how do you ensure that the read calculated is accurate and in line with specified procedures?	The response should address all approaches to deeming reads such as electronically via the EAC/AA calculator, manual calculation etc. For each of the methods utilised, the response should consider the following: 1. The procedures in place for identifying the need to calculate a deemed read. 2. The controls in place to ensure that all appropriate data is passed to, and from, your EAC/AA system and your NHHDC system. 3. The procedures for ensuring deemed reads are		

Question	Guidance	Response	Evidence
	calculated as per the BSC where the EAC/AA Calculator is not used.		
8.1.9 How do you ensure that all calculated, estimated and actual consumption data is transmitted to the appropriate Data Aggregator (on a D0019 data flow – Metering System EAC/AA Data) completely, accurately and on a timely basis?	The response should address the following areas: 1. A schedule of expected transmission dates/times is drawn up and maintained, such that staff are made aware and the transmissions made are monitored, to ensure the timetable is met. 2. All relevant data for transmission is collated completely, accurately and in the required format, including: (a) All EAC and AA values calculated by the EAC/AA calculation process. (b) Initial EAC values for new Metering Systems or on change of Profile Class or Standard Settlement Configuration. (c) Revised EACs for Unmetered Supplies. (d) Revisions to EAC/AA values sent previously. 3. The correct Data Aggregator(s) is identified. 4. File sequence numbers are maintained for each recipient Data Aggregator to ensure all are		

Question	Guidance	Response	Evidence
	processed, and in the correct order. 5. Record counts and check sums are provided in the data transmitted to ensure completeness. 6. Where the DTN is not used for transmission, an acknowledgement check is performed to confirm receipt of the files by the NHHDA.		

Question	Guidance	Response	Evidence
8.1.10 What controls do you have in place to ensure that the requirements of BSCP504 are met when Change of Supplier/Change of Agent notifications are processed? (BSCP504 3.2.3, 3.2.4, 3.2.5, 3.2.6 & Appendix 4.8)	The response should include the following key events, which may take place as part of the Change of Agent ('CoA')/ Change of Supplier ('CoS') process: 1. The processing of request for Metering System related details on a D0170 data flow both as the incoming and outgoing agent. 2. The processing of an instruction to obtain change of Supplier reading on a D0072 data flow on a CoS or CoA event. 3. The controls in place over your Agency Service to ensure the creation and complete and accurate sending of historic Meter reading data on a D0010 data flow and Metering System historical EAC/AA data on a D0152 data flow per BSCP504 3.2.3. 4. The mechanisms in place to monitor the timescales in which the above data flows: into and out of your Agency Service; and is processed.		
8.1.11 How do you ensure that appropriate procedures are in place to revise the EAC/AA in the event that historic standing	The response should address the following areas: 1. The procedures for identifying changes that may affect the EAC/AA calculated for an MSID.		

Question	Guidance	Response	Evidence
data or Meter reads change in line with the requirements of BSCP504 and PSL100?	2. The procedures for re-submitting changed data to the EAC/AA Calculator and ensuring that the new EAC/AA data is transmitted to the Data Aggregator.		
8.1.12 What action have you taken to ensure that where a read has been received post Final Reconciliation Settlement Run (RF) but no read pre RF, that the BSC rule is applied as specified in BSCP504 Appendix 4.5.	The response should address the following areas: BSCP504 Appendix 4.5 specifies that where the EAC for a Metering System supplied to NHHDA for inclusion in a Final Reconciliation Settlement Run has not been submitted with an AA for the Metering System, the NHHDC should have procedures in place to: 1. Determine a Deemed Meter Advance (DMA) for each Settlement Register using the specified formula. 2. Determine an EAC/AA value for each register substituting the value of Meter Advance (MA) with the DMA and the Meter Advance Period (MAP) with the Deemed Meter Advance Period (DMAP). 3. Determine an MA for each register for the period as specified. 4. Determine EAC/AA for each register using the		

Question	Guidance	Response	Evidence
	MA and the new MAP as calculated.		
8.1.13 What action have you taken to ensure that where a Supplier requests that a site should be treated as Long Term Vacant (LTV) (or where this ceases to be the case) the appropriate BSC rules are applied as set out in S-2?	BSCP504 sections 3.3.13 and 3.3.14 set out the process to be followed by the NHHDC when notified by a Supplier that either a site qualifies or no longer qualifies for LTV treatment. Please detail the processes and controls in place to address the following: At the start of the LTV period: 1. Processing of notifications from Suppliers of zero-EACs received on D0052 data flows. 2. Sending of notifications of deemed Meter readings (as appropriate) for the EFD of the LTV period to the Supplier and LDSO on D0010 data flows. At the end of the LVT period: 1. Processing of non-zero EACs received from the Supplier on D0052 data flows. 2. Obtaining or processing Meter readings. 3. Notification of deemed Meter readings to the Supplier and LDSO as appropriate.		

Question	Guidance	Response	Evidence
8.1.14 How have you ensured that appropriate audit trails are in place per BSCP504 Sections 4.16 and 4.17 and PSL100 Section 9.1, 10.2 and 10.3?	The response should address the existence of audit trails over the following areas: 1. Changes to standing data. 2. Changes to Meter reads. 3. Changes to EAC/AA or DMA calculations. 4. A history of all data flows (manual and electronic) received and sent out. In all circumstances you should consider whether there is enough information available for an independent person to identify the source and nature of the change (archived information should be stored so that it is available for enquiry). This should include a rationale for decisions that were made.		
8.1.15 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1) Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A 2) Data submissions to PAA@elexon.co.uk are made in accordance with the time table specified in BSCP533~~Submissions are in accordance with the specified timescales/calendar to~~		

Question	Guidance	Response	Evidence
	~~PAA@elexon.co.uk~~ 3) Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats ~~and BSCP533 Appendix B Calculation Guidelines~~) 4) Controls in place for data validity and completeness 5) Demonstration of a full understanding of the obligations and requirements of PARMS.		
8.1.1~~6~~5 How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and PSL100 Section 10.2.1?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement data for: 1. 28 months after the Settlement Day to which it relates on-line; 2. Until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra-Settlement Determination. The response should address the following: a) Controls to ensure that any archived data can be retrieved within 10 Business Days.		

Question	Guidance	Response	Evidence
	b) Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		

8.2-8.3 NO CHANGES

SECTION 9 – HHDC

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your Agency Service to ensure the operational requirements of the BSC, BSCP502 and PSL100 are met. Whilst Sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a HHDC agent.

Guidance for completing this section

The HHDC agent collects and validates metered data for SVA Metering Systems with half hourly Metering Equipment (HH SVA Metering Systems) for onward submission to the relevant HHDA agent. The HHDC agent is required to send active energy data to the HHDA in kWh. The section is split as follows:

Business Processes and Mitigating Controls: This set of questions looks at the controls over the input of Meter readings to the HHDC service and the subsequent transmission of data to the HHDA agent. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement), the provisions for a full audit trail history of the data used by your Agency Service, and any changes made to it as outlined in BSCP502.

Exception Management: This set of questions looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. This section of the SAD is concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means (e.g. email, fax letter).

9.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
9.1.1 How do you ensure that standing data is received and processed completely, accurately and in a timely manner, in line with the requirements of BSCP502 and PSL100?	The HHDC Agent receives a number of key inputs, including the following: 1. Appointment and termination notifications from Suppliers on D0155 and D0151 data flows (including read frequency requests) (BSCP502 3.2, 3.3). 2. Notification of change to other parties from Suppliers on a D0148 data flow (BSCP502 3.2 & 3.3). 3. Confirmation or rejection of energisation status change on a D0139 data flow from Meter Operator Agents (BSCP502 3.3, & 3.3). 4. MDD data flows from SVAA on D0269 and D0270 data flows (BSCP502 3.1). 5. Notification of Measurement Class /EAC/Profile Class on a D0289 data flow (BSCP502 3.2 & 3.3). 6. Half Hourly Meter Technical Details on a D0268 data flow (BSCP502 3.2, 3.3, and 3.5), including those for Unmetered Supplies and, where relevant, a Complex Site Supplementary Information Form. 7. Notification of address details on a D0131 data flow. The response should address the following areas: (a) The identification, review and authorisation of		

Question	Guidance	Response	Evidence
	all data flows prior to processing. (b) Controls in place to ensure that all data required or expected is received. This may be through controls within the update routines or through manual controls. (c) The validation of data for formats and lengths, e.g. the MSID is valid. (d) The validation of standing data received against the latest version of MDD and data held such as Measurement Class, Data Aggregator ID, Data Collector ID, Meter Operator Agent ID, Supplier ID, GSP Group or energisation status. (e) The validation of data for its internal consistency. (f) The controls over the completeness and accuracy of MDD data in line with the go-live dates as published in the MDD circulars, including controls to ensure that where MDD items are selectively applied to the database, that the appropriate items are selected and that all are applied completely and accurately. Please specify whether this process will require manual intervention.		
9.1.2 Where your retrieval system is separate from your data processing system, what controls do you have in place to ensure that Meter readings collected by one system are	This question is only relevant to Party Agents operating separate data retrieval and data processing systems. Where this is not relevant please state "not applicable". Controls should be in place to ensure that, where these activities are separate, each system is updated		

Question	Guidance	Response	Evidence
transferred completely and accurately to the other?	with all required standing data in order for it to perform its function. Procedures should ensure that data held by different parts of the system is consistent.		
9.1.3 How do you ensure that all appropriate Meter readings are collected to satisfy BSCP502 requirements? (BSCP502 3.4.1)	The response should address the following areas: 1. The controls in place to ensure the completeness of Meter read collection and upload onto the system; this should include both manual and electronic Meter reads (including both dial up reads and those received on D0010 data flows). 2. Reporting processes in place to identify failed dial up attempts (non collection of read data). 3. Appropriate review, follow-up (e.g. investigation of communication links, notification to the SVA HHMOA) and resolution of exceptions reported on a failed dial-up report. 4. Estimation of data where meters are missing data for a specific time period (refer to question 9.1.5).		
9.1.4 How do you ensure that Meter data is validated to satisfy BSCP502?	The response should address the type and level of validation undertaken. The minimum validation requirements for Meter data are set out in BSCP502 Appendix 4.1. The response should specify where the validation is performed (may be split between different parts of the system where data retrieval is separate to data		

Question	Guidance	Response	Evidence
	processing). Controls should be in place to ensure that the validation is performed on all Meter read types – including manual and those received on D0010 data flows. Where relevant controls should be in place to ensure that the 'mini-MAR' is preformed as required by BSCP502 Appendix 4.1.5.		
9.1.5 Where actual reads cannot be collected, how do you ensure that appropriate procedures for the estimation of reads in line with BSCP502 are imposed?	Estimation has to be performed by the HHDC when data is invalid or is missing, and the HHDC has to notify the relevant Supplier and where appropriate the LDSO, of the method used to produce the data estimate. The methods of estimation are set out in BSCP502 Appendix 4.2. The response should address the following areas: 1. The estimation methods undertaken by your Agency Service and how these calculations are checked for completeness and accuracy. 2. Controls in place to ensure that the estimation method applied follows the order of precedence set out in BSCP502 Appendix 4.2. 3. Processes in place to ensure that the method of estimation used and the rationale behind the application of that method are recorded. 4. Specific procedures for abnormal consumption patterns should be in place.		

Question	Guidance	Response	Evidence
	5. Controls should be in place to ensure that where more accurate data becomes available (either actual of estimated), this is applied.		
9.1.6 How do you ensure that all consumption data is transmitted completely, accurately and on a timely basis to the appropriate Data Aggregator (on a D0036 data flow – Validated half hourly advances)?	The response should address the following areas: 1. A schedule of expected transmission dates/times is drawn up and maintained, such that staff are made aware and the transmissions made are monitored, to ensure the timetable is met. 2. All relevant data for transmission is collated completely and accurately in the required format. 3. The correct Data Aggregator(s) is identified. 4. File sequence numbers are maintained for each recipient Data Aggregator to ensure all are processed, and in the correct order. 5. Record counts and check sums are provided in the data transmitted to ensure completeness. 6. Where the DTN is not used for transmission, an acknowledgement check is performed to confirm receipt of the files by the HHDA.		

Question	Guidance	Response	Evidence
9.1.7 What controls do you have in place to ensure that the requirements of BSCP502 are met when change of agent/concurrent change of agent and change of Supplier notifications are processed? (BSCP502 3.2.4.8 & 3.2.7.8)	The response should consider the following key events, which may take place as part of the change of agent/concurrent change of agent and change of Supplier process: 1. The processing of a request for Metering System related details on a D0170 data flow both as the incoming and outgoing Party Agent. 2. The controls in place to ensure the creation and complete, accurate and timely sending of historic Meter reading data, on request, for the requested period of time, on a D0010 data flow and D0036 data flow – including the last physical and final register readings and a consumption history of up to 14 months. 3. The controls in place to ensure the complete, accurate and timely processing of all D0010 and D0036 data flows upon receipt from the old HHDC. 4. The mechanisms in place to monitor the timescales in which the above data are processed. Note. The upload of all other data flows in relation to a change of agent should already have been referred to in the response to question 9.1.1.		
9.1.8 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1) Calculations are in accordance in with the calculation guidelines specified in BSCP533		

Question	Guidance	Response	Evidence
	Appendix A 2) Submissions are in accordance with the specified timescales/calendar to PAA@elexon.co.uk 3) Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats ~~and BSCP533 Appendix B Calculation Guidelines)~~ ~~—~~Controls in place for data validity and completeness 4) 5) Demonstration of a full understanding of the obligations and requirements of PARMS.		
9.1.~~9~~8 How have you ensured that appropriate audit trails are in place per PSL100 Sections 1.1.6 10.2, 10.3 and 5.2.1.?	The system must record and store for audit purposes the information detailed below. The response should address the existence of audit trails over the following: 1. Data collected by the HHDC from the SVA Metering Systems including Meter period value data cumulative readings and maximum demand readings. 2. Any metered data provided to the HHDC by the associated Supplier or the associated Meter Operator Agent.		

Question	Guidance	Response	Evidence
	3. The details of the validation done on the collected data including: (i) the alarm(s) returned by the Meter resulting in changes to data; (ii) a reason code where data is changed; and (iii) the new value for changed data. 4. All data totalled by SVA Metering System by the HHDC. In all circumstances you should consider whether there is enough information available for an independent person to identify the source and nature of the change (archived information should be stored so that it is available for enquiry). The audit trail and archiving requirements for HHDC are set out in PSL100 sections 10.2 and 10.3		
9.1.10~~9~~ How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and PSL100 Sections 10.2 and 10.3?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement data for: 1. 28 months after the Settlement Day to which it relates on-line; 2. Until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra-Settlement Determination. The response should address the following: a) Controls to ensure that any archived data can be		

Question	Guidance	Response	Evidence
	retrieved within 10 Business Days. b) Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		
9.1.11~~0~~ What procedures are in place to ensure that correct Supplier details are received and that authorised Allocation Schedules are applied in accordance with BSC requirements? (OPTIONAL QUESTION IN RESPECT OF SHARED SVA METER ARRANGEMENTS FOR HALF HOURLY IMPORT AND EXPORT ACTIVE ENERGY)	Only those Applicants seeking Qualification as a HHDC agent with shared Meter allocation functionality should address this question. Shared SVA Meter Arrangements are where up to four Suppliers utilise the same Metering Equipment or Metering System in the measurement of Import and/or Export Energy, referred to as Meter splitting. This can apply to two Suppliers (one Import, one Export) and can also apply where the Import and the Export can be split between two Suppliers (giving a total of four). The response should consider the controls and processes in place to ensure: 1. Primary and Secondary Supplier details and their associated MSIDs are notified and recorded accurately. 2. Consistent Primary and Secondary Supplier SMRA registration details are received for each Shared SVA Meter arrangement and only one HHMOA and one HHDC are appointed. 3. The HHDC processes data in accordance with the BSC requirements. (In particular, the algorithm used in the Active Energy metering data split calculations supports both the		

Question	Guidance	Response	Evidence
	percentage and block methods of allocation and is in accordance with BSC requirements). 4. Receipt of authorised Allocation Schedules prior to Gate Closure, (including formal controls/ procedures to ensure that only correct and authorised amendments to the Allocation Schedules are processed). 5. Allocation Schedules have been correctly applied for each whole (or part) Settlement day. 6. Each Shared SVA Meter Arrangement, and in each half hour, the sum of the allocated Active Energy data between the two MSIDs equals the total for the Metering System. 7. Timely and accurate transfer of the split Meter data allocations between the Suppliers, for each MSID, to the appropriate HHDAs and the LDSOs are in place. 8. A full audit trail is maintained over the output data from the Algorithm used to split data. The metered Export or Import original data input to the algorithm and the calculated output values are retained. 9. Documented procedures over the implementation of sole Supplier trading from existing Shared SVA Meter arrangements.		

9.2-9.3 NO CHANGES

SECTION 10 – NHHDA

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your Agency Service to ensure the requirements of the BSC, BSCP505 and PSL100 are met. Whilst sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a NHHDA agent.

Guidance for completing this section

The NHHDA agent aggregates non half hourly EAC and AA values received from NHHDC agents according to the registration data held by the SMRA. The aggregated data is then passed to the SVAA in accordance with the Settlement timetable. The section is split as follows:

Business Processes and Mitigating Controls: This section looks at the controls over the input of EAC/AA values and the transmission of aggregated data to the SVAA agent. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement), the provision for a full audit trail history of the data used by your Agency Service and any changes made to it as outlined in PSL100.

Exception Management: The section looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. This section of the SAD is concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means (e.g. email, fax or letter).

10.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
10.1.1 How do you ensure that the data is received and processed completely, accurately and in a timely manner, inline with the requirements of BSCP505 and PSL100?	The NHHDA receives a number of key inputs: 1. Registration data from SMRA (standing data and Metering System data) on a D0209 data flow (BSCP505 3.2.1 and 3.2.2). 2. EAC and AA data received from NHHDC agents on a D0019 data flow (BSCP505 3.3.1). 3. MDD, Data Aggregation timetable and Settlement timetable on D0269, D0270 and D0286 data flows (BSCP505 3.1.3). The response should address the following areas: a) The identification, review and authorisation of flows prior to processing. b) Controls in place to ensure that all data required or expected is received. This may be through controls within the update routines or through manual controls. c) The validation of data for formats and lengths, e.g. the MSID is valid (instruction file validation BSCP505 Appendix 4.2.1). d) The validation of standing data		

Question	Guidance	Response	Evidence
	received against the latest version of MDD, data items and combinations such as Profile Class, Standard Settlement Configuration, Data Aggregator ID, Data Collector ID, Meter Operator Agent ID, Supplier ID, Measurement class, GSP Group or energisation status (NHHDA appointment changes – BSCP505 4.2.2, NHHDC appointment changes - BSCP505 4.2.3). e) The validation of Metering System data received e.g. Measurement Class is non half hourly for the whole of the Meter Advance Period (MAP), Standard Settlement Configuration, Supplier, energisation status and Measurement Class have not changed in the middle of a MAP and sets of history data include Metering System data effective on the Settlement date of the earliest MAP (SVA Metering System standing data changes - BSCP505 4.2.4). f) The validation of consumption data received, e.g. all MAPs are contiguous and if data contains EAC and AA data then EAC effective from Settlement date is the day after the latest AA effective to Settlement		

Question	Guidance	Response	Evidence
	date (NHHDC Consumption data BSCP505 4.2.6). g) The validation of data for its internal consistency. h) Controls to ensure that where MDD items are selectively applied to the database, that the appropriate items are selected and that all are applied completely and accurately. Please specify whether this process will require manual intervention.		
10.1.2 How do you ensure that the aggregation process is performed in accordance with the Settlement timetable and that the transmission of the Supplier Purchase Matrix to the SVAA is complete and accurate?	The NHHDA agent transmits the Supplier Purchase Matrix to SVAA on a D0041. The response should address the following areas: 1. A schedule of aggregation runs and expected transmission times and dates is prepared and issued to staff. 2. Aggregation run numbers are allocated to ensure that all are processed in the correct order. 3. All appropriate GSP Group combinations are included in the aggregation run. 4. Aggregation runs and files sent are monitored/reviewed to ensure that timetables are		

Question	Guidance	Response	Evidence
	met. 5. File sequence numbers, record counts and check sums are included in the data transmitted to ensure completeness. 6. Where the Data Transfer Network has not been utilised, receipt acknowledgements received from SVAA are checked to ensure completeness of transmission. 7. Processes are in place to re-run an aggregation/transmission should processing problems be encountered.		

Question	Guidance	Response	Evidence
10.1.3 How will you ensure that a full refresh is requested from the SMRA at least once a year and that any selective refreshes are requested as required as per BSCP505 section 3.2.3?	The response should address the following areas: 1. Procedures should be in place to ensure that the NHHDA agent requests a full refresh from SMRA on an annual basis. (BSCCo have issued guidance on the processing of the refresh and have issued a timetable – discuss with BSCCo to obtain information). 2. Procedures are in place to identify circumstances in which a selective refresh is required. 3. Controls should be in place to ensure that where a selective refresh is required, the SMRA is notified in a timely manner. 4. Controls should be in place to ensure that the refresh is applied in accordance with the requirements set out in BSCP505.		
10.1.4 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1. Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A 2. Submissions are in accordance with the specified timescales/calendar to PAA@elexon.co.uk 3. Data is submitted in the required file format		

Question	Guidance	Response	Evidence
	specification (in accordance of BSCP533 Appendix A PARMS Text File Formats) ~~and BSCP533 Appendix B Calculation Guidelines)~~ 4. Controls in place for data validity and completeness 5. Demonstration of a full understanding of the obligations and requirements of PARMS.		
10.1.5~~4~~ How have you ensured that you have appropriate audit trails in place?	The systems should be capable of reporting (or archived information should be stored so that it is available for enquiry) sufficient information so as to enable a user to obtain, in a timely fashion: 1. A breakdown of any aggregated information calculated. 2. Any changes to standing data held or used by the system. The audit trail and archiving requirements for NHHDA are set out in PSL100 sections 10.2 and 10.3.		
10.1.6~~5~~ How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement data for: 1. 28 months after the Settlement Day to which it		

Question	Guidance	Response	Evidence
PSL100 Sections 10.2 and 10.3?	relates on-line; 2. until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra-Settlement Determination. The response should address the following: 4. Controls to ensure that any archived data can be retrieved within 10 Business Days. 5. Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		
10.1.7~~6~~ What version of the NHHDA software will you go-live with and how will you ensure that the correct version is used on an ongoing basis?	Change management procedures should be detailed in section 5. In addition to providing information as to version of software at go-live provide any additional controls with respect to version control if not covered by section 5. The response should address the following areas: 1. Controls should be in place to ensure that the developer supports the version of software in use.		

Question	Guidance	Response	Evidence
	2. On an ongoing basis, controls should be in place to ensure that, as new versions of software are received and implemented, that these are tested in the Party Agent's own environment – i.e. some form of user acceptance testing is carried out and where relevant regression testing.		

10.2-10.3 NO CHANGES

SECTION 11 – HHDA

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your Agency Service to ensure the requirements of the BSC, BSCP503 and PSL100 are met. Whilst sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a HHDA agent.

Guidance for completing this section

The HHDA agent aggregates half hourly Meter readings received from the HHDC agents. The aggregated data is then passed to the SVAA in accordance with the Settlement timetable. The section is split as follows:

Business Processes and Mitigating Controls: This section looks at the controls over the input of Half Hourly Meter readings and the transmission of aggregated data to the SVAA. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement), the processes for identifying errors (monitoring data quality), the provision for a full audit trail history of the data used by your Agency Service and any changes made to it as outlined in BSCP503.

Exception Management: The section looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. This section of the SAD is concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic data flows received via the Data Transfer Network and also manual data flows received via any other means (e.g. email, fax, letter).

11.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
11.1.1 How do you ensure that data is received and processed completely, accurately, and in a timely manner in line with the requirements of BSCP503 and PSL100?	The HHDA receives a number of key inputs: 1. Registration data from SMRA on D0209 data flows (BSCP503 3.2.1 and 3.2.2). 2. Estimated and actual consumption data received from HHDC agents on D0036 data flows (BSCP503 3.3.1). 3. MDD, Data Aggregation timetables and Settlement timetables from the SVAA on D0269 and D0270 data flows (BSCP503 3.1.3). 4. Line Loss Factor changes from LDSOs on D0265 data flows (BSCP503 3.3.1). 5. BM Unit allocations or changes from Suppliers on D0297 data flows (where the Applicant is seeking Qualification as a HHDA following agreement with its associated Supplier(s) to implement additional BM Units) (BSCP503 3.5). The response should address the following areas: (a) The identification, review and authorisation of flows prior to processing. (b) Controls are in place to ensure that all data		

Question	Guidance	Response	Evidence
	required is received. This may be by controls within the update routines or by manual controls (you should include details as to how you will ensure that you have been notified of all changes to Line Loss Factors). (c) The validation of data for formats and lengths (e.g. the MSID is valid) (BSCP503 Appendix 4). (d) The validation of data for its internal consistency. (e) The validation of standing data received against the latest version of MDD, data items such as Measurement Class, Data Aggregator ID, Data Collector ID, GSP Group, Line Loss Factor details or energisation status (BSCP503 4.1.2 to 4.1.7). (f) The validation of Line Loss Factor data (BSCP503 4.2). (g) The validation of BM Unit files (BSCP503 4.5).		
11.1.2 How do you ensure that the aggregation process is performed in accordance with the Settlement timetable and that the transmission of the Aggregated Half Hour Data	The response should address the following areas: 1. A schedule of aggregation runs and expected transmission times and dates is prepared and issued to staff. 2. Aggregation run numbers are allocated to ensure		

Question	Guidance	Response	Evidence
(D0040) or BM Unit Half Hourly Aggregated Data (D0298) to SVAA is complete and accurate?	that all are processed in the correct order. 3. Controls are in place to ensure that data is aggregated by each GSP Group for each associated Supplier for each Settlement day and separate totals for each BM Unit are maintained. 4. File sequence numbers, record counts and check sums are included in the data transmitted to ensure completeness. 5. Where the DTN has not been utilised, receipt acknowledgements received from SVAA are checked to ensure completeness of transmission. 6. Aggregation runs are monitored/reviewed to ensure that timetables are met. 7. Processes are in place to re-run an aggregation/transmission should processing problems be encountered.		
11.1.3 How will you ensure that a full refresh is requested from the SMRA at least once a year?	Procedures should be in place to ensure that the HHDA Agent request a full refresh from SMRA on an annual basis. (BSCP503 3.2.2). BSCP503 Appendix 4.1.7 sets out the validation requirements to be performed on receipt of the refresh. Controls should be in place to ensure that the		

Question	Guidance	Response	Evidence
	refresh is applied in accordance with the requirements set out in BSCP505.		
11.1.4 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1. Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A 2. Submissions are in accordance with the specified timescales/calendar to PAA@elexon.co.uk 3. Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats ~~and BSCP533 Appendix B Calculation Guidelines~~) 4. Controls in place for data validity and completeness 5. Demonstration of a full understanding of the obligations and requirements of PARMS.		
11.1.~~5~~4 How will you ensure that you have appropriate audit trails in place to meet the requirements as set out in PSL100?	The systems should be capable of reporting (or archived information should be stored so that it is available for enquiry) sufficient information so as to enable a user to obtain, in a timely fashion: 1. A breakdown of any aggregated information		

Question	Guidance	Response	Evidence
	calculated. 2. Any changes to standing data held or used by the system. The audit trail and archiving requirements for HHDA are set out in PSL100 sections 10.2 and 10.3.		
11.1.~~65~~ How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and PSL100 Sections 10.2 and 10.3?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement Data for: 1. 28 months after the Settlement Day to which it relates on-line; 2. Until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra Settlement Determination. The response should address the following: a) Controls to ensure that any archived data can be retrieved within 10 Business Days. b) Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		

11.2-11.3 NO CHANGES

SECTION 12 – SMRA

Objectives of this section

The objective of this section is to consider the controls that have been built into your systems and processes supporting your Agency Service to ensure the operational requirements, as defined in BSCP501 and PSL100 are met. Whilst sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as an SMRA.

Guidance for completing this section

As per the BSC, an LDSO is required to provide a SMRS for the registration of Metering Systems (in SVA) in accordance with the Master Registration Agreement (MRA). Whilst Sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a SMRA. The section is split as follows:

Business Processes and Mitigating Controls: This section looks at the controls over the input of both standing data and MSID information to your Agency Service(s) and the subsequent transmission to the Data Aggregator. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement) the provisions for a full audit history of the data used by your Agency Service, and any changes made to it as outlined in PSL100.

Exception Management: The section looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. In this section of the SAD you are concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents. There are numerous methods of monitoring the quality of your data and the benchmarks that you use should be tailored to your Agency Service and the specific risks posed to your data quality.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means (e.g. email, fax, letter).

12.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
12.1.1 What controls do you have to ensure that all standing data and MSID information and all details on changes of Supplier, Data Aggregator, Data Collector and Meter Operator are recorded completely, accurately and in a timely manner, in line with BSCP501 (Sections 1.6 and 3)?	The SMRA receives a number of different inputs: 1. D0269 and D0270 MDD data flows from SVAA (BSCP501 3.1). 2. Appointment details and changes from a Supplier on D0055 and D0205 data flows (BSCP501 3.3, 3.4, 3.5, 3.6, 3.7 & 3.10). 3. Metering System Data (D0171) from a SMRA (BSCP501 3.2, 3.6, 3.9 & 3.10). The response should address the following areas: a) All flows are identified, reviewed and authorised prior to processing. b) The validation of data for formats and lengths, e.g. the MSID is valid. c) Controls in place to ensure that all data expected or required is received. This may be through controls within the update routines or through manual controls. d) The controls over the completeness and accuracy of MDD data in line with the go-live dates as published in MDD circulars. Where MDD is only selectively loaded controls should be in place to		

Question	Guidance	Response	Evidence
	determine what to load and to ensure that the load is in line with the 'go live' dates for the relevant version. e) The validation of the data received against the latest version of MDD, data items and combinations such as the Profile Class (NHH only), SSC (NHH only), DA Id, DC Id, MOA Id, Supplier Id, Measurement Class, GSP Group, Energisation Status or LLFC. f) The validation of data for its internal consistency, e.g. if the Measurement Class changes from NHH to HH the DA/DC/MOA appointments are also changed.		
12.1.2 Following data updates within SMRA, how do you ensure complete and accurate D0209 flows are sent to each relevant Data Aggregator in a timely manner?	BSCP501 (1.6 and 3.2-3.10) require that a D0209 flow be sent to the appointed Data Aggregator following a change to any of the MSID information. The response should address the following areas: 1. Processes/controls in place to identify all updates to the system that require a D0209 to be sent. 2. The correct Data Aggregator is identified as the recipient of the D0209. 3. File sequence numbers are maintained for each recipient Data Aggregator to ensure all are		

Question	Guidance	Response	Evidence
	processed and in the correct order. 4. Record counts and check sums are provided in the data transmitted to ensure completeness. 5. Where the DTN is not used for transmission, an acknowledgement check is performed to confirm receipt of the files by the DA. 6. Processes are in place to ensure all necessary data for the D209 is collated from your system.		
12.1.3 How do you ensure the correct response to a request for a 'refresh' of Metering System data from an appointed Data Aggregator is actioned (BSCP501 1.6, 3.8 and Appendix 4.5?	The response should address the following areas: 1. Controls are in place to validate the request to ensure it has come from a valid source and is in respect of MSIDs that the source is appointed to. 2. Processes are in place to ensure the refresh file sent to the Data Aggregator is complete and accurate. This should also include processes to ensure the correct amount of history is included in the refresh file. 3. Timescales for responding to any such requests are in accordance with BSCP501, PSL100 and/or agreed with the Data Aggregator and are documented and monitored by management (this may also include receiving an acknowledgement		

Question	Guidance	Response	Evidence
	from the Data Aggregator that the request has been satisfied).		
12.1.4 How do you ensure that all Supplier Registration Errors (Objections) are processed completely, accurately and in a timely manner, in line with BSCP501 (1.6, 3.4,4.2 and Appendix 4.4)?	The response should address the following areas: 1. Controls are in place to ensure that all D0064 and D0068 flows are identified and processed. 2. The D0064 is validated against the relevant MSID information already held in the SMRA system: a) If the D0064 is invalid, e.g. the old Supplier was not the previously registered Supplier, a D0066 is sent back. b) If the D0064 is valid a D0065 is sent back to the old Supplier, a D0067 is sent to the new Supplier and the registration is reverted back to the old Supplier. c) If the objection is not removed by the old Supplier, within the objection period, a D0092 is sent to the old Supplier and a D0093 is sent to the new Supplier. 3. Where the old Supplier withdraws the objection during the objection period on a D0068: a) It is validated against the objections		

Question	Guidance	Response	Evidence
	currently raised to ensure it is valid, if invalid it is rejected and a D0069 sent back to the old Supplier. b) If the D0068 is valid, a D0090 is sent to the old Supplier, a D0091 to the new Supplier and the change of Supplier registration is re-instated.		
12.1.5 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1. Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A 2. Submissions are in accordance with the specified timescales/calendar to PAA@elexon.co.uk 3. Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats ~~and BSCP533 Appendix B Calculation Guidelines~~) 4. Controls in place for data validity and completeness 5. Demonstration of a full understanding of the obligations and requirements of PARMS.		

Question	Guidance	Response	Evidence
12.1.65 How have you ensured that appropriate audit trails are in place?	The system should be capable of reporting (either from 'live' data or from data archived but available for review, as per PSL100 Section 10) sufficient information so as to enable a user to obtain, in a timely manner, any changes to standing data held or used within the system and the linkages/relationships to the flows received and sent. The audit trail requirements are set out inBSCP501 Section 1.4 and PSL100 Section .10.		
12.1.76 How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and PSL100 Section 10.2?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement Data for: 1. 28 months after the Settlement Day to which it relates on-line; 2. Until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra Settlement Determination. The response should address the following: a) Controls to ensure that any archived data can be retrieved within 10 Business Days. b) Systems and procedures to ensure that all data		

Question	Guidance	Response	Evidence
	that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		
12.1.8~~7~~ How have you ensured that you can operate in all GSP Groups? SMRAs that are seeking re-Qualification in order to operate in multiple GSP Groups should refer to BSCP537 Appendix 3.5 for details of the requirements that must be met.	All new SMRAs are required to be able to operate in all GSP Groups. The response should address the following: 1. Controls to ensure that for each MSID registered in the SMRS the correct GSP Group is recorded within the system. 2. Testing (as described in Section 3) has been performed to demonstrate that the Agency Service can operate those processes and procedures detailed in BSCP501 in multiple GSP Groups.		

12.2-12.3 NO CHANGES

SECTION 13 – SVA HHMOA

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your SVA HHMOA Agency Service to ensure the requirements of the BSC, BSCP514, BSCP550 and PSL100 are met. Whilst Sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a SVA HHMOA Agent.

Guidance for completing this section

The SVA HHMOA is responsible for the installation and maintenance of half hourly Metering Systems. The SVA HHMOA is required to provide requested data to other Parties and to inform Parties impacted by any changes made to Metering Systems as set out in BSCP514 and BSCP550. The section is split as follows:

Business Processes and Mitigating Controls: This section looks at the controls over the input of Metering System technical data or energisation status data received and the transmission of Metering System technical data, energisation status or Meter reads to HHDC Agents. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement), the provision for a full audit trail history of the data used by your Agency Service and any changes made to it as outlined BSCP514 and in PSL100.

Exception Management: The section looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. In this section of the SAD you are concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means e.g. email, fax, letter.

13.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
13.1.1 How do you ensure that data is received and processed completely accurately and in a timely manner, in line with the requirements of BSCP514, BSCP550 and PSL100?	The SVA HHMOA receives a number of key inputs: 1. D0155, D0151, D0148 from Suppliers relating to appointments and Party Agent changes. (BSCP514 5.2.1, 5.2.2, 5.2.3, 5.2.4, 5.2.5, 5.2.6, 7.1, 7.2, 7.3 and 7.4). 2. D0170 from Suppliers, NHHDCs and other Metering System Operators requesting Metering System details. (BSCP514 5.2.1, 5.2.4, 5.2.5, 5.2.6, 7.3 and 7.4). 3. D0268, D0289, D0149, D0150, D0010 and D0215 from Suppliers, other Metering System Operators and LDSOs providing Metering System technical details or Metering System readings. (BSCP514 5.2.1, 5.2.2, 5.2.3, 5.2.4, 5.2.5, 5.3.5, 7.1, 7.2, 7.3 and 7.4). 4. D0134 and D0139 from Suppliers, other Metering System operators and LDSOs requesting and providing energisation status changes (BSCP514 5.3.1 and 5.3.2). 5. D0142 from Suppliers requesting installation, removal or changes to Metering Systems (BSCP514 5.3.3 5.3.4, 5.3.6, 7.1, 7.2 and 7.4).		

Question	Guidance	Response	Evidence
	The response should address the following areas: a) All flows are identified, reviewed and authorised prior to processing. b) The validation of data for formats and lengths, e.g. the MSID is valid. c) The validation of data for its internal consistency. d) Controls in place to ensure that all data required or expected is received. This may be through controls within the update routines or through manual controls.		
13.1.2 How do you ensure that once data has been collected that is has been passed to the appropriate recipient completely, accurately and in a timely manner.	The key inputs received are set out in 13.2.1 and where relevant the SVA HHMOA is required to take the appropriate action which might include, for example, the provision of Metering System technical details and Meter readings to other parties – notably to HHDC Agents. The response should address the following areas: 1. Controls should be in place to ensure that the appropriate action for each request or provision of data is taken, all instructions should be logged and progress monitored to ensure they are actioned in a timely manner.		

Question	Guidance	Response	Evidence
	2. Management should have monitoring controls in place in order to determine whether the appropriate action has been taken in each case. 3. Controls should be in place to ensure that data sent (regardless of method) has been sent to the appropriate recipient, has been authorised for sending and potentially any acknowledgement received has been checked - in an electronic environment these may include: a) File sequence numbers are maintained to ensure that all are processed and in the correct order. b) Record counts and check sums are included in the data transmitted to ensure completeness. c) Receipt acknowledgements received are checked to ensure completeness of transmission (only relevant where the DTN has not been used).		
13.1.3 What controls do you have in place to ensure that data or Meter readings obtained by field operators is	The response should address the following areas: 1. Standard forms/input methodologies should be used to collect and retain data from work		

Question	Guidance	Response	Evidence
recorded completely and accurately in the SVA HHMOA database?	schedules. 2. Scheduled work/site visits should be monitored against actual work/site visits performed. 3. Expected data/information to be received from the site visits should be measured against actual data/information received.		
13.1.4 How do you ensure that all installed Metering Systems either conform to the metering Codes of Practice (CoP) or that an appropriate Metering Dispensation has been obtained?	The response should address the following areas: 1. An inventory of all Metering Systems installed should be maintained which specifies all Metering System technical details – where relevant this should be supported by the appropriate certificates and paper work (e.g. CT/VT certificates) and an audit trail should be provided from the inventory to the physical documentation. 2. Controls should be in place to identify Metering Systems that require a dispensation and to monitor the expiry dates of any dispensations held. 3. An inventory of all Metering Systems which have a dispensation should be maintained, which specifies the duration of each.		

Question	Guidance	Response	Evidence
13.1.5 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1. Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A 2. Submissions are in accordance with the specified timescales/calendar to PAA@elexon.co.uk 3. Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats ~~and BSCP533 Appendix B Calculation Guidelines~~) 4. Controls in place for data validity and completeness 5. Demonstration of a full understanding of the obligations and requirements of PARMS.		
13.1.~~6~~5 How will you ensure that you have appropriate audit trails in place to meet the audit trail requirements as set out in PSL100?	The systems should be capable of reporting (or archived information should be stored so that it is available for enquiry) sufficient information so as to enable a user to obtain, in a timely fashion any changes to standing data held or used by the system. The audit trail and archiving requirements for SVA HHMOA are set out in PSL100 sections 10.2 and 10.3.		

Question	Guidance	Response	Evidence
13.1.~~7~~6 How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and PSL100 sections 10.2 and 10.3?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement Data for: 1. 28 months after the Settlement Day to which it relates on-line; 2. Until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra Settlement Determination. The response should address the following: a) Controls to ensure that any archived data can be retrieved within 10 Business Days. b) Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		
13.1.~~8~~7 What controls do you have in place to ensure that all commissioning tests are conducted to meet the requirements detailed in CoP 4, Appendix A?	The response should address the following areas: 1. Controls and procedures should be in place to identify all circumstances where a commissioning test is required. 2. All commissioning tests are performed in a		

Question	Guidance	Response	Evidence
	timely manner (e.g. where applicable, prior to registration). 3. All relevant documentation is retained and is available for retrieval. 4. Transfer of documentation to the new SVA HHMOA on CoA. 5. Commissioning tests performed meet the requirements detailed in CoP 4, Appendix A.		

13.2-13.3 NO CHANGES

SECTION 14 – SVA NHHMOA

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your SVA NHHMOA Agency Service to ensure the requirements of the BSC, BSCP514 and PSL100 are met. Whilst Sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a SVA NHHMOA.

Guidance for completing this section

The SVA NHHMOA is responsible for the installation and maintenance of non half hourly Metering Systems. The SVA NHHMO is required to provide requested data to other Parties and to inform Parties impacted by any changes made to Metering Systems as set out in BSCP514. The section is split as follows:

Business Processes and Mitigating Controls: This section looks at the controls over the input of Metering System technical data or energisation status data received and the transmission of Metering System technical data, energisation status or Meter reads to NHHDC Agents. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement), the provision for a full audit trail history of the data used by your Agency Service and any changes made to it as outlined in BSCP514 and PSL100.

Exception Management: The section looks at the specific controls in place to report on, monitor and resolve exceptions during the processing of data.

A number of questions in the SAD relate to 'data quality'. In this section of the SAD you are concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means e.g. email, fax, letter.

14.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
14.1.1 How do you ensure that data is received and processed completely accurately and in a timely manner, in line with the requirements of BSCP514 and PSL100?	The SVA NHHMOA receives a number of key inputs: 1. D0155, D0151, D0148 from Suppliers relating to appointments and Party Agent changes (BSCP514 6.2.1, 6.2.2, 6.2.3, 6.2.4, 6.2.5, 7.1, 7.2, 7.3 and 7.4). 2. D0170 from Suppliers and other Meter Operators requesting Metering System details (BSCP514 6.2.1, 6.2.4, 7.1 and 7.2). 3. D0149, D0150, D0010, D0268, D0291 and D0215 from Suppliers, other Metering System Operators and LDSOs providing Metering System technical details or Meter readings (BSCP514 6.2.1, 6.2.2, 6.2.3, 6.2.4, 6.2.5, 6.3.3, 6.3.4, 6.3.5, 7.1, 7.2, 7.3 and 7.4). 4. D0134 and D0139 from Suppliers, other Metering System operators and LDSOs requesting and providing energisation status changes (BSCP514 6.3.1 and 6.3.2). 5. D0142 from Suppliers requesting installation, removal or changes to Metering Systems (BSCP514 6.2.2, 6.3.3, 6.3.4, 7.3 and 7.4).		

Question	Guidance	Response	Evidence
	The response should address the following areas: 1. All flows are identified, reviewed and authorised prior to processing. 2. The validation of data for formats and lengths, e.g. the MSID is valid. 3. The validation of data for its internal consistency. 4. Controls in place to ensure that all data required or expected is received. This may be through controls within the update routines or through manual controls.		
14.1.2 How do you ensure that once data has been collected that is has been passed to the appropriate recipient completely, accurately and in a timely manner.	The key inputs received are set out in 14.2.1 and where relevant the SVA NHHMOA is required to take the appropriate action which might include the provision of Metering System technical details and Meter readings to other parties – notably to NHHDC Agents. The response should address the following areas: 1. Controls should be in place to ensure that the appropriate action for each request or provision of data is taken, all instructions should be logged and progress monitored to ensure they are actioned in a timely manner.		

Question	Guidance	Response	Evidence
	2. Management should have monitoring controls in place in order to determine whether the appropriate action has been taken in each case. 3. Controls should be in place to ensure that data sent (regardless of method) has been sent to the appropriate recipient, has been authorised for sending and potentially any acknowledgement received has been checked - in an electronic environment these may include: a) File sequence numbers are maintained to ensure that all are processed and in the correct order. b) Record counts and check sums are included in the data transmitted to ensure completeness. c) Receipt acknowledgements received are checked to ensure completeness of transmission. d) Processes are in place to re-send transmissions should a failure occur.		
14.1.3 What controls do you have in place to ensure that data or Meter readings	The response should address the following areas: 1. Standard forms/input methodologies should be		

Question	Guidance	Response	Evidence
obtained by field operators are recorded completely and accurately in the SVA NHHMOA database and in a timely manner?	used to collect and retain data from work schedules. 2. Scheduled work/site visits should be monitored against actual work/site visits performed. 3. Expected data/information to be received from the site visits should be measured against actual data/information received.		
14.1.4 How do you ensure that all installed Metering Systems either conform to the metering Code of Practice or that an appropriate Metering Dispensation has been obtained?	The response should address the following areas: 1. An inventory of all Metering Systems installed should be maintained which specifies all Metering System technical details – where relevant this should be supported by the appropriate certificates and paper work (e.g. CT/VT certificates) and an audit trail should be provided from the inventory to the physical documentation. 2. Controls should be in place to identify Metering Systems that require a dispensation and to monitor the expiry dates of any dispensations held. 3. An inventory of all Metering Systems which have a dispensation should be maintained which		

Question	Guidance	Response	Evidence
	specifies the duration of each.		
14.1.5 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1. Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A 2. Submissions are in accordance with the specified timescales/calendar to PAA@elexon.co.uk 3. Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats ~~and BSCP533 Appendix B Calculation Guidelines~~) 4. Controls in place for data validity and completeness 5. Demonstration of a full understanding of the obligations and requirements of PARMS.		
14.1.~~6~~5 How have you ensured that you have appropriate audit trails in place to meet the audit trail requirements as set out in PSL100?	The systems should be capable of reporting (or archived information should be stored so that it is available for enquiry) sufficient information so as to enable a user to obtain, in a timely fashion any changes to standing data held or used by the system. The audit trail and archiving requirements for SVA		

Question	Guidance	Response	Evidence
	NHHMOA are set out in PSL100 sections 10.2 and 10.3.		
14.1.~~7~~6 How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and PSL100 section 10.2 and 10.3?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement Data for: 1. 28 months after the Settlement Day to which it relates on-line; 2. Until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra Settlement Determination. The response should address the following: a) Controls to ensure that any archived data can be retrieved within 10 Business Days. b) Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		
14.1.~~8~~7 What controls do you have in place to ensure that all commissioning tests are	The response should address the following areas: 1. Controls and procedures should be in place to identify all circumstances where a		

Question	Guidance	Response	Evidence
conducted to meet the requirements detailed in CoP 4, Appendix A?	commissioning test is required. 2. All commissioning tests are performed in a timely manner (e.g. where applicable, prior to registration). 3. All relevant documentation is retained and is available for retrieval. 4. Transfer of documentation to the new SVA HHMOA on CoA. 5. Commissioning tests performed meet the requirements detailed in CoP 4, Appendix A.		

14.2-14.3 NO CHANGES

SECTION 15 – NO CHANGES

SECTION 16 – METER ADMINISTRATOR

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your Agency Service to ensure the requirements of the BSC, BSCP520 and PSL100 are met. Whilst Sections 1 to 7 of the SAD are generic to all Agency Services, this section focuses on the specific controls required to operate effectively as a Meter Administrator.

Guidance for completing this section

The Meter Administrator (MA) is responsible for receiving summary inventory and latitude/longitude information from the Unmetered Supplies Operator (UMSO) and where relevant inputting this information into the Equivalent Meter (EM). Where the EM is Central Management Systems (CMS) Capable the MA is responsible for inputting the CMS Control File and receiving Event Log data from the CMS. In addition the MA is responsible for operating and maintaining the EM hardware and software, ensuring that metered data is available from the EM in time for the Data Collector to meet the Settlement timetable and indicating to the Data Collector where estimated data should be used where an EM is not functioning correctly. The section is split as follows:

Business Processes and Mitigating Controls: This section looks at the controls over the input of summary inventory and latitude/longitude data into the EM and the operation and maintenance of the metering equipment. It also considers the maintenance of standing data which, if incorrect, may impact upon Settlement, the provision for a full audit trail history of the data used by your Agency Service and any changes made to it as outlined in BSCP520 and PSL100.

Exception Management: The section looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. In this section of the SAD you are concerned with the on-going quality of your data when your Agency Service is live and in operation. The quality of the data used to initially populate your Agency Service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Agency Service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents. There are numerous methods of monitoring the quality of your data and the benchmarks that you use should be tailored to your Agency Service and the specific risks posed to your data quality.

Both system and manual controls should be considered when answering the SAD questions as your Agency Service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means e.g. email, fax, letter.

16.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
16.1.1 What controls do you have in place to ensure that the establishment of new UMS Inventory is done in accordance with the requirements of BSCP520?~~How do you ensure that you have a complete record for each Metering System and that this is updated for all changes in a timely manner?~~	The MA receives a number of key inputs from the UMSO and the Supplier: 1. Latitude and longitude information for each MSID is received on a P0068 and summary inventory details are received on a P0064 (BSCP520 3.1 to 3.7) and/or CMS Control file as appropriate.~~.~~ 2. Appointment and termination details are received from the Supplier on D0155, D0148 and D0151 flows~~.~~ ~~via an~~ electronically or other agreed method. The response should address the following areas: ~~—~~Summary inventory is validated against the Operational Information Document (OID)~~).~~ I~~i~~n what form will~~and~~ an audit trail be provided from the relevant inventory, ~~. to the physical documentation.and is~~and is the a) ~~D~~data in the ~~is in the~~ correct format?~~.~~ ~~a)An inventory of all Metering Systems installed should be maintained which specifies all Metering System technical details – where relevant this should be supported by the~~		

Question	Guidance	Response	Evidence
	~~appropriate certificates and paper work and an audit trail should be provided from the inventory to the physical documentation.~~ b) The EM type adopted utilises software which has been approved by BSCCo to provide settlement metered data in accordance with BSC Requirements. c) Controls to ensure ~~around the~~ population of data into the ~~Management reviews ensure that data is configured in the~~ EM ~~-~~system is carried out completely, accurately and in a timely manner. d) Procedures are in place to ensure that EM system parameters have been correctly configured and ~~assigned in~~ assigned in a timely manner. e) Monitoring procedures are in place to identify changes required to data in a timely manner and to ensure the EM is updated accordingly. f) All flows are identified, reviewed and authorised prior to processing. g) The validation of data for formats and lengths, e.g. the MSID is valid. h) Evidence is retained as to who processed the data, when and what was updated to the MA		

Question	Guidance	Response	Evidence
	database.		
16.1.2 How do you ensure that once a UMS connection has been established changes to inventories are processed completely and accurately in accordance with the requirements of BSCP520?~~16.1.2 How do you ensure that once data has been received that it has been passed to the appropriate recipient or the appropriate action has been taken completely and accurately?~~	The response should include the following key events: a) Receiving and processing of revised UMS inventories and/or CMS Control files as appropriate. b) Controls in place to identify required changes to data. c) Controls in place that changes are perreformed in a timely manner and the EM is updated accordingly. d) Controls in place to ensure that applications for revised inventories continue to meet the criteria specified in BSCP520.~~The key inputs received are set out in 17.1.1 and where relevant the MA is required to take the appropriate action which might include, for example, the provision of Metering System technical details to other parties – notably to Data Collectors.~~ ~~The response should address the following areas:~~ ~~1.Controls should be in place to ensure that the appropriate action for each request or provision of data is taken, all instructions should be logged and progress monitored to ensure they are actioned in a~~		

Question	Guidance	Response	Evidence
	~~timely manner.~~ ~~2.Controls should be in place to ensure that complete and accurate EM output data is delivered to the Data Collectors. The output data is transferred in a timely manner to ensure settlement timescales are met.~~ ~~3.Management should have monitoring controls in place in order to determine whether the appropriate action has been taken in each case.~~ ~~4.Controls should be in place to ensure that data sent (regardless of method) has been sent to the appropriate recipient, has been authorised for sending and any acknowledgement received has been checked.~~		
16.1.3 How do you ensure that information and data flows relating to UMS are sent or received and processed completely, accurately and in a timely manner in accordance ~~of~~with BSCP520?	The response should include~~d~~ the following key events: 1. Provision of UMS ~~-~~summary inventories via the P0064 data flow ~~-~~and/or CMS Control file as appropriate 2. Provision of Equivalent Meter Technical Details via the P0068 data flow 3. Receipt and processing of appointment details via data flows		

Question	Guidance	Response	Evidence
	4. Sending of P0173 and P0174 to Data Collectors 5. Receipt and processing of CMS Event Log file The response should address the following: 1. All flows are identified, reviewed and authorised prior to processing~~.~~ 2. The validation of data~~e~~ flows for format and length~~s~~ 3. The validation of data for ~~its internal consistency for~~ completeness and accuracy (e.g. the MSIDs is valid). a. Where the generating/sending of flows requires the use of MDD the response should reference how it is ensured that data in the flow is validated against the latest version of MDD~~t this data is valid.~~ b. Where an agreed method other than the standard DTC flow is to be used the response should address: • How you manage the approval/agreement of receipt/sending of data in another agreed format; • What records are retained of the		

Question	Guidance	Response	Evidence
	agreement of the method as well as the actual data received/sent; and • How do you ensure that timescales surrounding this data are adhered to. Controls in place to ensure that all data required or expected is received and that all data to be sent is sent in a timely manner. This may be through controls within the routine or through manual controls.		
16.1.4 What controls do you have in place to ensure that the requirements of BSCP520 are met when a Change of Supplier (CoS) and/or Change of Agent (CoA) event takes places?	The response should cover how you identify when a CoS/CoA activity has taken place and should address the following: For HH UMS CoS: a) Receipt and processing of appointment flows; and b) Receipt and processing of P0068 EM Technical Details (latitude and longitude information) and P0064 Summary Inventory . Change of MA: a) Receipt and processing of appointment flow and/or termination flow; and b) Sending and processing of requests for transfer		

Question	Guidance	Response	Evidence
	of information between old and new MA.~~Request sufficient information from MA and old MA to validate transferred information~~ Change of Data Collector: a) Receipt and processing of notification of ~~c~~Change of ~~a~~Agent flows (D0148); and b) Sending of P0173 and P0174 and all information transferred.		
16.1.5 What controls do you have in place to ensure that the requirements of BSCP520 are met for EM Fault Reporting?	The response should address the following areas: 1. Monitor and manage the receipt of notification of a~~n~~ fault/inconsistency; 2. Action required to investigate the fault/inconsistency reported; 3. Identify the period of the fault and notify relevant participants; and 4. Rectify data and send Data Collector corrected data. The response should address the following areas: a) Procedures in place to ensure that timescales and requirements are in accordance with BSCP520		

Question	Guidance	Response	Evidence
	Controls in place to monitor progress of EM Fault Reporting		
16.1.6~~3~~ Where Dynamic Equivalent Metering Systems are used, what procedures are in place to ensure that Photo Electric Cell Unit (PECU) Arrays are installed, configured and maintained correctly?	The response should address the following areas: 1. Documented procedures are in place over the set up, installation and testing of the PECU Array(s) and associated communications equipment. These procedures should encompass tests to confirm that information can be retrieved from the PECU Array(s) to meet operational requirements and settlement run timescales. 2. Procedures are in place to establish the load weighted numbers of Unmetered Apparatus controlled by PECUs to ascertain the correct proportion of PECUs on a PECU Array. These procedures also ensure that for each PECU in an Array, type and location details are maintained within the Equivalent Meter system. 3. Procedures are in place to monitor and maintain the correct operation of the PECU Array(s). These procedures encompass the review of any spurious or unusual performance of PECUs within the Array. Failed cells within an Array are replaced in a timely manner.		

Question	Guidance	Response	Evidence
	4. Procedures are in place covering the use of appropriate default PECU regimes and/or switching regimes in the event that PECU Array data is not available for any day.~~Procedures are in place covering the use of default PECU switching regimes in the event that PECU Array data is not available for any day.~~		
16.1.74 How have you ensured that you have appropriate audit trails in place?	Your systems should be capable of reporting (or archived information should be stored so that it is available for enquiry) sufficient information so as to enable a user to obtain, in a timely fashion any changes to standing data held or used by the system. The audit trail and archiving requirements for MA are set out in PSL100 sections 10.2 and10.3		
16.1.85 How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6 and PSL100 sections 10.2 and10.3?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement Data for: 1. 28 months after the Settlement Day to which it relates on-line; 2. Until the date 40 months after the Settlement Day to which it relates in an archive; and 3. At the request of the Panel, for more than 40 months if needed for an Extra Settlement		

Question	Guidance	Response	Evidence
	Determination. The response should address the following: a) Controls to ensure that any archived data can be retrieved within 10 Business Days. b) Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		

16.2-16.3 NO CHANGES

SECTION 17 – NO CHANGES

SECTION 18 – SUPPLIER

Objectives of this section

The objective of this section is to consider the controls that have been built into the systems and processes supporting your Supplier service to ensure the operational requirements of the BSC and BSCPs are met. Whilst Sections 1 to 7 of the SAD are generic to all Qualified Persons, this section focuses on the specific controls required to operate effectively as a Supplier.

Guidance for completing this section

The Supplier is responsible for appointing its agents and registering these details with the SMRA. The Supplier is also responsible for managing the performance of its appointed agents and for monitoring the completion of business processes that it has initiated. This section is split as follows:

Business Processes and Mitigating Controls: This set of questions looks at the controls over the provision of data to your agents, the subsequent processing of information received and the transmission of this updated data to your agents. It also considers the maintenance of standing data (which, if incorrect, may impact upon Settlement) and any changes made to it.

Exception Management: The section looks at the specific controls you have in place to report on, monitor and resolve exceptions during the processing of your data.

A number of questions in the SAD relate to 'data quality'. This section of the SAD is concerned with the on-going quality of your data when your Supplier service is live and in operation. The quality of the data used to initially populate your service is considered in Section 7 of the SAD. A number of the questions in the service specific sections of the SAD relate to how you will ensure the accuracy of incoming and outgoing data and in the event that poor quality data does enter your Supplier service, how you identify and resolve this to minimise the impact upon other Parties and Party Agents.

Both system and manual controls should be considered when answering the SAD questions as your service will rely on both system and manual processes to effectively fulfil its obligations. Responses should consider the procedures in place for dealing with electronic flows received via the DTN and also manual data flows received via any other means (e.g. email, fax letter).

18.1 Business processes and mitigating controls

Question	Guidance	Response	Evidence
18.1.1.1 How do you ensure that data flows are sent or received and processed completely, accurately and in a timely manner, in line with the requirements of the BSCPs?	The response should describe the processes you have in place for dealing with Settlement related data flows and should address the following: 1. How all data flows are identified, reviewed and authorised prior to processing 2. The validation of data for formats and lengths (e.g. the MSID is valid and other data items (where applicable) have been checked against the latest version of MDD) 3. The validation of data (where applicable against the latest version of MDD) for its internal consistency, for completeness and accuracy 4. Controls in place to ensure that all data required or expected is received and that all data to be sent is sent in a timely manner. This may be through controls within the update routines or through manual controls. 5. Where data is to be sent or received to or from parties by agreed methods other than via the DTN how you: • manage the approval or agreement of receipt/sending of data in another agreed		

Question	Guidance	Response	Evidence
	format, • record and retain the agreement of the method as well as the actual data received or sent; and • ensure that timescales surrounding this data are adhered to.		
18.1.1.2 What controls and procedures are in place to ensure the accurate, complete and timely sending, receiving and processing of data flows for key Settlement related events?	The response should make reference to the following key events: 1. Sending of appointment and termination notifications on a D0155, D0153 and D0151 data flow and processing of rejection data flows. 2. Sending of notification of changes to other parties on a D0148 data flow and notification of customer details on a D0302 data flow. 3. Sending of registration details to the SMRA to register a specific Metering System on a D0055 data flow and processing of rejections received on a D0057 data flow. 4. Sending of read frequency requests and Metering System Settlement Details affirmations on D0052 data flows (including D0052s sent for Unmetered Supplies) and processing of data flows received		

Question	Guidance	Response	Evidence
	in response. 5. Receipt and processing of Market Domain Data on D0269 and D0270 data flows. 6. Receipt of and processing of data flows from the SVAA. 7. Requests for changes to energisation status on a D0134 data flow and subsequent processing of D0139 data flows (confirmation or rejection of energisation status change) and monitoring of outstanding D0139 data flows. 8. Processing of Meter Technical Details from Meter Operator Agents on D0149 and D0150 (non half hourly metering) and D0268 (half hourly metering) following installation of meters 9. Requests for Installation or change to a Metering System Functionality or the Removal of all Meters on D0142 data flows and processing of D0171 data flows. 10. Updates to registration details on D0205 data flows and processing of rejection flows. 11. Receipt and processing of P0068 and P0170 for HH, and P0207 for NHH, flows for Unmetered		

Question	Guidance	Response	Evidence
	Supplies. 12. Requests for Disconnection of Supply on D0132 data flows and processing of confirmations on D0125 data flows. 13. Mechanisms for the identification and follow up of missing data. The response to this question may cross refer to the response given in 18.1.1.1 but should include details of processes and controls in place specific to the above events. Further questions on data flows relating to key processes are included in questions 18.1.2 and 18.1.3 and further questions relating to exceptions handling are included in question 18.2.1.		

Question	Guidance	Response	Evidence
18.1.2 What controls do you have in place to ensure that the requirements of the BSCPs are met when a Change of Supplier (CoS), Change of LDSO, and or Change of Agent (CoA) event takes place?	The response to this question may cross refer to the response given in 18.1.1. The response should address the following: 1. Sending of appointment and termination notifications on a D0155, D0153 and D0151 data flow and processing of rejection (D0261) and acceptance (D0011) data flows. 2. The sending of an Instruction to Obtain Change of Supplier Reading on a D0072 dataflow on a CoS or CoA event. 3. The sending of Customer Own Readings for CoS on D0071 data flows. 4. The receipt and processing of Change of Supplier Readings received on D0086 data flows. 5. The sending of Request for Metering System Related Details on D0170 data flows. 6. The sending and processing of Metering Technical Details and Metering Reading History on CoA by the old and new agents. ~~7.~~The mechanisms in place to monitor the timescales in which the above data flows into and out of your Supplier service and is processed.		

Question	Guidance	Response	Evidence
	~~8.Sending of PARMS data to the PAA.~~ 7.		
18.1.3 How do you ensure that when a Change of Measurement Class (from NHH to HH and vice versa) is required the necessary flows are sent and received?	The response should address the following: 1. Sending of notification of MC/EAC/PC on D0289 data flows. 2. The sending of Request for Installation or Changes to Metering System Functionality or the Removal of all Meters on D0142 data flows and the processing of failures received on D0221 data flows. 3. The sending of Request for Metering System Related Details on D0170 data flows and the provision of this information on D0150, D0149 and D0268 data flows are sent and received by the relevant HHMOA and NHHMOA.		
18.1.4 How do you ensure that only those sites that meet the criteria for treatment as a Long Term Vacant (LTV) are treated as such in accordance with the obligations in the BSC and BSCP504?	Where a Supplier treats or intends to treat NHH Metering Systems as LTV the Supplier should comply with the relevant sections of the BSC (S2.8, S-2 4.3.19 – 4.3.22). The response should detail the processes and controls in place to address the following: 1. Only those sites that meet the necessary criteria		

Question	Guidance	Response	Evidence
Applies to NHH Suppliers only	are treated as LTV. 2. Ongoing monitoring is performed to confirm that sites continue to meet the criteria. 3. Proactive processes should be in place to ensure that all reasonable endeavours are taken to contact the owner of the property to obtain a Meter reading. 4. Once sites no longer meet the criteria action is taken to notify the NHHDC and ensure that a non-zero EAC is submitted to the NHHDA on a D0019 data flow for the correct end date of the LTV period. 5. Complete and accurate audit trails are in place to demonstrate the Suppliers compliance with the requirements of the BSC and BSCP504. 6. Details of sites treated as LTV are passed to the LDSO on request.		
18.1.5 How do you ensure that your agents are meeting their obligations under the BSC?	Where obligations are to be fulfilled by an agent the Supplier should have controls in place to ensure that those obligations are met. The response should demonstrate examples of the controls/procedures in place for the ongoing		

Question	Guidance	Response	Evidence
	management of your agents, such as: 1. Controls to ensure that your agents are Qualified and that their qualified status is maintained on an ongoing basis. 2. Controls to ensure that your agents are compliant with their BSC obligations and a mechanism for assurance that your agents implement BSC Modifications or Changes appropriately. ~~3.~~Regular meetings and reporting of key performance indicators, for example: 3. ~~i) to ensure performance level requirements for PARMS purposes are met~~ i~~i~~) to ensure the submission of aggregation data such as consumption figures and the Supplier Purchase Matrix is in line with Settlement timetable. 4. Adequate contractual arrangements that include clear lines of responsibility and escalation. 5. Clear roles and responsibilities for each party and documented working practice agreed.		

Question	Guidance	Response	Evidence
18.1.6 What controls and procedures do you have in place to ensure that the requirements of BSCP533 are met?	The response should address the following: 1. Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A 2. Submissions in accordance with the specified timescales/calendar to PAA@elexon.co.uk 3. Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats ~~and BSCP533 Appendix B Calculation Guidelines~~) 4. Controls in place for data validity and completeness 5. Demonstration of a full understanding of the obligations and requirement of PARMS.		
18.1.7~~6~~ How have you ensured that appropriate audit trails are in place to support the rationale for decisions made in the event of queries/disputes being raised?	The response should address how you ensure that there is enough information available for an independent person to identify the source and nature of changes (archived information should be stored so that it can be accessed for enquiry). This should include a rationale for decisions that were made. The response should also address how you deal with ad hoc requests made by your agents and other parties		

Question	Guidance	Response	Evidence
	and what record of such requests is maintained.		
18.1.~~7~~ 8 How have you ensured that you can meet the data retention requirements set out in BSC Section U1.6?	Section U1.6 sets out the requirements on Parties and their Party Agents to retain Settlement Data for: ~~4.~~1. 28 months after the Settlement Day to which it relates on-line; ~~5.~~2. Until the date 40 months after the Settlement Day to which it relates in an archive; and ~~6.~~3. At the request of the Panel, for more than 40 months if needed for an Extra Settlement Determination. The response should address the following: ~~c)~~a) Controls to ensure that any archived data can be retrieved within 10 Business Days. ~~d)~~b) Systems and procedures to ensure that all data that is retained is in a form in which the data can be used in carrying out a Settlement Run or Volume Allocation Run.		

18.2-18.3 NO CHANGES

SVG109/01 - Attachment E

Balancing and Settlement Code

Code of Practice One

CODE OF PRACTICE FOR THE METERING OF CIRCUITS WITH A RATED CAPACITY EXCEEDING 100MVA FOR SETTLEMENT PURPOSES

Issue 2

Version 5.0

DATE: 25 June 2009

Code of Practice One

CODE OF PRACTICE FOR THE METERING OF CIRCUITS WITH A RATED CAPACITY EXCEEDING 100MVA FOR SETTLEMENT PURPOSES.

1. Reference is made to the Balancing and Settlement Code for the Electricity Industry in Great Britain, and in particular, to the definition of "Code of Practice" in Annex X-1 thereof.

2. This is Code of Practrice One, Issue 2, Version 5.0.

3. This Code of Practice shall apply to Metering Systems comprising Metering Equipment that are subject to the requirements of Section L of the Balancing and Settlement Code.

4. This Code of Practice is effective from 25 June 2009.

5. This Code of Practice has been approved by the Panel.

AMENDMENT RECORD

ISSUE	DATE	VERSION	CHANGES	AUTHOR	APPROVED
Draft	18/3/93	0.10	Recommended to PEC	MSC	
1	15/4/93	1.00	Endorsed by PEC	CoP WG	
1	Code Effective Date[1]	1.00	Re-badging of Code of Practice One for the implementation of the Balancing and Settlement Code	BSCCo	Panel 16/11/00 (Paper 07/003)
1	BETTA Effective Date	2.0	BETTA 6.3 Rebadging changes for the CVA Feb 05 Release	BSCCo	
2	23/02/06	3.0	CP1051 changes for the February 06 Release	BSCCo	ISG/55/002
2	06/11/08	4.0	CP1238 for November 08 Release	BSCCo	ISG88/01SVG88/ 02
2	25/06/09	5.0	CP1264 for June 09 Release	BSCCo	ISG94/01 SVG94/02

[1] "Code Effective Date" means the date of the Framework Agreement.

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CONTENTS

FOREWORD

This Code of Practice defines the minimum requirements for the Metering Equipment required for the measurement and recording of electricity transfers at Defined Metering Points where the rated circuit capacity exceeds 100MVA.

For the purpose of this Code of Practice the rated circuit capacity in MVA shall be determined by the lowest rated primary plant (eg transformer rating, line rating, etc) of the circuit. The Metering Equipment provision and accuracy requirements shall anticipate any future up-rating consistent with the installed primary plant. The primary plant maximum continuous ratings shall be used in this assessment.

For the purpose of this Code of Practice, the use of summation current transformers shall not be permitted. The use of interposing current transformers is permitted providing the overall Metering System accuracy is maintained.

Where a material change to a Metering System takes place, then this Metering System must be modified to comply with the most up to date version of this Code of Practice. Changes to a Metering System are considered to be material where they constitute a change to:

i. Switchgear containing measurement transformers; and/or
ii. The primary plant associated with the Metering System i.e. measurement transformers.

Where a Metering Dispensation applies and where the Actual Metering Point is not at the Defined Metering Point, a material change affecting the Defined Metering Point may not affect the Metering System at the Actual Metering Point.

BSCCo shall retain copies of, inter alia, this Code of Practice together with copies of all documents referred to in it, in accordance with the provisions of the Balancing and Settlement Code ("the Code").

1. SCOPE

This Code of Practice states the practices that shall be employed, and the facilities that shall be provided for the measurement and recording of the quantities required for Settlement purposes on each circuit where the rated capacity exceeds 100MVA.

It derives force from the Code, and in particular the metering provisions (Section L), to which reference should be made. It should also be read in conjunction with any relevant BSC Procedures.

This Code of Practice does not contain the calibration, testing and commissioning requirements for Metering Equipment used for Settlement purposes. These requirements are detailed in Code of Practice Four – "Code of Practice for Calibration, Testing and Commissioning Requirements for Metering Equipment for Settlement Purposes".

Metering Dispensations from the requirements of this Code of Practice may be sought in accordance with the Code and BSCP32.

Meters and Outstations referred to in this Code of Practice shall only achieve successful compliance in respect of any testing detailed in this Code of Practice if the requirements set out in accordance with BSCP601 are also observed and successfully completed or the Registrant has been granted a valid Metering Dispensation covering any departure from the requirements as detailed in this Code of Practice.

In the event of an inconsistency between the provisions of this Code of Practice and the Code, the provisions of the Code shall prevail.

2. REFERENCES

The following documents are referred to in the text:-

BS EN 62053-22	Electricity metering equipment (a.c.). Particular requirements. Static meters for active energy (classes 0.2 S and 0.5 S)
BS EN 62053-23	Electricity metering equipment (a.c.). Particular requirements. Static meters for reactive energy (classes 2 and 3)
BS EN 62056-21	Electricity Metering. Data exchange for meter reading, tariff and load control. Direct local data exchange
BS EN 60044-3	Instrument transformers. Combined transformers
IEC 60044-1	Instrument transformers. Current transformers
IEC 60044-2	Instrument transformers. Inductive voltage transformers
Balancing and Settlement Code	Section X; Annex X-1 and Section L and BSC Procedures
Code of Practice Four	Code of Practice for Calibration, Testing and Commissioning Requirements for Metering Equipment for Settlement Purposes
BSC Procedures	BSCP06, BSCP32, BSCP601
Electricity Act 1989	Schedule 7 as amended by Schedule 1 to the Competition and Services (Utilities) Act 1992.

3. DEFINITIONS AND INTERPRETATIONS

Save as otherwise expressly provided herein, words and expressions used in this Code of Practice shall have the meanings attributed to them in the Code and are included for the purpose of clarification.

Note: * indicates definitions in the Code.
Note: † indicates definitions which supplement or complement those in the Code.
Note: ‡ indicates definitions specific to this Code of Practice

3.1 Active Energy *

Active Energy means the electrical energy produced, flowing or supplied by an electrical circuit during a time interval, and being the integral with respect to time of the instantaneous Active Power, measured in units of watt-hours or standard multiples thereof.

3.2 Active Power *

Active Power means the product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof, that is:-

1,000 Watts = 1 kW
1,000 kW = 1 MW

3.3 Actual Metering Point ‡

Actual Metering Point means the physical location at which electricity is metered.

3.4 Apparent Energy ‡

Apparent Energy means the integral with respect to time of the Apparent Power.

3.5 Apparent Power ‡

Apparent Power means the product of voltage and current measured in units of voltamperes and standard multiples thereof, that is:-
1,000 VA = 1 kVA
1,000 kVA = 1 MVA

3.6 Central Data Collection Agent (CDCA) *

Central Data Collection Agent means the BSC Agent for Central Data Collection in accordance with Section E of the Code.

3.7 Communication Line

Communication Line means a line or link which is dedicated to an Outstation System and is identified by a unique number, e.g. CTN line number 123, PSTN line number 321 or IP address 555.

3.8~~7~~ CTN ‡

CTN means the Electricity Supply Industry (ESI) corporate telephone network.

3.9~~8~~ CVA ‡

CVA means "Central Volume Allocation"

3.10~~9~~ CVA Customer †

CVA Customer means any customer, receiving electricity directly from the Transmission System, irrespective of from whom it is supplied.

3.11~~0~~ Defined Metering Point ‡

Defined Metering Point means the physical location at which the overall accuracy requirement as stated in this Code of Practice are to be met. The Defined Metering Points are identified in Appendix A and relate to Boundary Points and System Connection Points.

3.12~~1~~ Demand Period ‡

Demand Period means the period over which Active Energy, Reactive Energy or Apparent Energy are integrated to produce Demand Values. For Settlement purposes, each Demand Period shall be of 30 minutes duration, one of which shall finish at 24:00 hours.

3.13~~2~~ Demand Values ‡

Demand Values means, expressed in MW, Mvar or MVA, twice the value of MWh, Mvarh or MVAh recorded during any Demand Period[2]. The Demand Values are half hour demands and these are identified by the time of the end of the Demand Period.

3.14~~3~~ electricity *

"electricity" means Active Energy and Reactive Energy.

3.15~~4~~ Export †

Export means, for the purposes of this Code of Practice, an electricity flow as indicated in Figure 1 of Appendix B.

3.16~~5~~ Import †

Import means, for the purposes of this Code of Practice, an electricity flow as indicated in Figure 1 of Appendix B.

3.17~~6~~ Interrogation Unit ‡

[2] Please note that these Demand Values are for use with CVA Metering Systems. SVA Metering Systems shall use units a factor of 10^3 smaller than CVA e.g. kW rather than MW.

Interrogation Unit means a Hand Held Unit "HHU" (also known as Local Interrogation Unit "LIU") or portable computer which can enter Metering Equipment parameters and extract information from the Metering Equipment and store this for later retrieval.

3.187 Meter *

Meter means a device for measuring Active Energy and/or Reactive Energy.

3.198 Metering Equipment *

Metering Equipment means Meters, measurement transformers (voltage, current and combination units), metering protection equipment including alarms, circuitry, associated Communications Equipment and Outstation and wiring.

3.2019 Meter Register ‡

Meter Register means a device, normally associated with a Meter, from which it is possible to obtain a reading of the amount of Active Energy, or the amount of Reactive Energy that has been supplied by a circuit.

3.210 Outstation *

Outstation means equipment which receives and stores data from a Meter(s) for the purpose, inter-alia, of transfer of that metering data to the Central Data Collection Agent (CDCA) or a Data Collector as the case may be and which may perform some processing before such transfer and may be in one or more separate units or may be integral with the Meter.

3.221 Outstation System ‡

Outstation System means one or more Outstations linked to a single ~~communication~~ Communication ~~l~~Line.

3.232 PSTN ‡

PSTN means the public switched telephone network.

3.243 Password ‡

For Meters with integral Outstations: 'Password' means a string of characters of length no less than six characters and no more than twelve characters, where each character is a case insensitive or sensitive alpha character (A to Z) or a digit (0 to 9) or the underscore character (_). Passwords must have a minimum of 2,000,000 combinations, for example six characters if composed of any alphanumeric characters or eight characters if composed only of hexadecimal characters (0 to F). The characters of a hexadecimal password must be in upper case.

For separate Outstations: a Password may be described as above for integral Outstations or a single password of any format[3].

3.2~~5~~4 Rated Measuring Current ‡

Rated Measuring Current means the rated primary current of the current transformers in primary plant used for the purposes of measurement.

3.2~~6~~5 Reactive Energy *

Reactive Energy means the integral with respect to time of the Reactive Power.

3.2~~7~~6 Reactive Power *

Reactive Power means the product of voltage and current and the sine of the phase angle between them, measured in units of voltamperes reactive and standard multiples thereof;

3.2~~8~~7 Registrant *

means, in relation to a Metering System, the person for the time being registered in CMRS or (as the case may be) SMRS in respect of that Metering System pursuant to Section K of the Balancing and Settlement Code.

3.2~~9~~8 Settlement Instation ‡

Settlement Instation means a computer based system which collects or receives data on a routine basis from selected Outstation by the Central Data Collection Agent or (as the case may be) a relevant Data Collector.

3.3~~0~~29 SVA ‡

SVA means "Supplier Volume Allocation".

3.3~~1~~0 SVA Customer *

means a person to whom electrical power is provided, whether or not that person is the provider of that electrical power; and where that electrical power is measured by a SVA Metering System.

[3] Meters separate from their Outstation and capable of external communications should have the same password requirements as for separate Outstations.

4. MEASUREMENT CRITERIA

4.1 Measured Quantities and Demand Values

The following measured quantities and Demand Values are for use with CVA Metering Systems. SVA Metering Systems shall use units a factor of 10^3 smaller than CVA e.g. kWh rather than MWh.

4.1.1 Measured Quantities

For each separate circuit the following energy measurements are required for Settlement purposes:-

(i) Import MWh

(ii) Export MWh

(iii) Import Mvarh

(iv) Export Mvarh

4.1.2 Demand Values

For each Demand Period for each circuit the following Demand Values shall be provided:-

(i) Import MW

(ii) Export MW

(iii) Import Mvar

(iv) Export Mvar

4.2 Accuracy Requirements

4.2.1 Overall Accuracy

The overall accuracy of the energy measurements at or referred to the Defined Metering Point shall at all times be within the limits of error as shown:-

(i) Active Energy

CONDITION	LIMIT OF ERRORS AT STATED SYSTEM POWER FACTOR	
Current expressed as a percentage of Rated Measuring Current	Power Factor	Limits of Error
120% to 10% inclusive	1	± 0.5%
Below 10% to 5%	1	± 0.7%
Below 5% to 1%	1	± 1.5%
120% to 10% inclusive	0.5 lag and 0.8 lead	± 1.0%

(ii) Reactive Energy

CONDITION	LIMIT OF ERRORS AT STATED SYSTEM POWER FACTOR	
Current expressed as a percentage of Rated Measuring Current	Power Factor	Limits of Error
120% to 10% inclusive	Zero	± 4.0%
120% to 20% inclusive	0.866 lag and 0.866 lead	± 5.0%

These limits of error for both (i) and (ii) above shall apply at the Reference Conditions defined in the appropriate Meter specification.

Evidence to verify that these overall accuracy requirements are met shall be available for inspection by the Panel or Technical Assurance Agent.

4.2.2 Compensation for Measurement Transformer Error

To achieve the overall accuracy requirements it may be necessary to compensate Meters for the error of the measurement transformers and the associated leads to the

Meters. Values of the compensation shall be recorded and evidence to justify the compensation criteria, including wherever possible test certificates, shall be available for inspection by the Panel or Technical Assurance Agent.

4.2.3 Compensation for Power Transformer and Line Losses

Where the Actual Metering Point and the Defined Metering Point do not coincide then a Metering Dispensation shall be applied for and, where necessary, compensation for power transformer and/or line losses shall be provided to meet the overall accuracy at the Defined Metering Point.

The compensation may be achieved either within the Metering Equipment or within the Data Collector's software.

Where compensation is applied the values used shall be recorded and supporting evidence to justify the compensation criteria shall be available for inspection by the Panel or Technical Assurance Agent.

5. METERING EQUIPMENT CRITERIA

Although for clarity this Code of Practice identifies separate items of equipment, nothing in it prevents such items being combined to perform the same task provided the requirements of this Code of Practice are met.

Metering Equipment other than outdoor measurement transformers, shall be accommodated in a clean and dry environment.

5.1 Measurement Transformers

All measurement transformers shall be of a wound construction.

For each circuit current transformers (CT) and voltage transformers (VT) shall meet the requirements set out in clauses 5.1.1 and 5.1.2.

Additionally, where a combined unit measurement transformer (VT & CT) is provided the 'Tests for Accuracy' as covered in clause 8 of BS EN 60044-3 covering mutual influence effects shall be met.

For Metering Systems that represent low burdens on measurement transformers, consideration shall be given as to whether that operating burden is within the operating range of the measurement transformers. In such cases it may be necessary to add additional burden.

Guidance for the use of multi core cables is provided in Appendix E.

5.1.1 Current Transformers

Two sets of current transformers in accordance with IEC 60044-1 and with a minimum standard of accuracy class 0.2S (irrespective of the secondary current rating of the current transformers) shall be provided.

The current transformers supplying the main Meters shall be dedicated to that purpose.

The current transformers supplying the check Meters may be used for other purposes provided the overall accuracy requirements in paragraph 4.2.1 are met and evidence of the value of the additional burden is available for inspection by the Panel or Technical Assurance Agent. The additional burden shall not be modified without prior notification to the Panel, and the evidence of the value of the modified additional burden shall be available for inspection by the Panel or Technical Assurance Agent.

CT test certificates showing errors at the overall working burden or at burdens which enable the working burden errors to be calculated shall be available for inspection by the Panel or Technical Assurance Agent.

The total burden on each current transformer shall not exceed the rated burden of such CT.

5.1.2 Voltage Transformers

Two voltage transformers or one voltage transformer with two or more secondary winding sets in accordance with IEC 60044-2 and with a mininum standard of accuracy class 0.2 shall be provided.

The VT secondary winding supplying the main Meters shall be dedicated to that purpose.

The VT secondary winding supplying the check Meters may be used for other purposes provided the overall accuracy requirements in clause 4.2.1 are met and evidence of the value of the additional burden is available for inspection by the Panel or Technical Assurance Agent. The additional burden shall not be modified without prior notification to the Panel, and evidence of the value of the modified additional burden shall be available for inspection by the Panel or Technical Assurance Agent.

A VT test certificate(s) showing errors at the overall working burden(s) or at burdens which enable the working burden errors to be calculated shall be available for inspection by the Panel or Technical Assurance Agent.

The total burden on each secondary winding of a VT shall not exceed the rated burden of such secondary winding.

Separately fused VT supplies shall be provided for each of the following:-

(a) the main Meter
(b) the check Meter
(c) any additional burden

Such fuses shall be located as close as practicable to the VT.

5.1.3 Monitoring of Voltage Transformers

Where a common mode fault, such as a VT fuse failure, could cause incorrect voltages on both the main and check Meters, Meters combining integral Outstations shall provide for the data to be identified with an alarm indicating phase failure.

For separate Outstations, an alarm may be used which shall incorporate a time-delay feature so as to avoid spurious operation. This alarm shall provide notification of a phase failure by the next Working Day at a point which is normally manned.

A spare channel on the Outstation or any other available means may be used to transmit the alarm.

5.1.4 Measurement Transformers Installed on Existing Circuits

Where circuits, other than those newly installed, are to be metered to this Code of Practice and where the installed measurement transformers do not comply fully with clauses 5.1.1 & 5.1.2, then such measurement transformers may be used providing the requirements in clauses 4.2.1 and 5.1.3 are met.

5.2 Testing Facilities

Separate test terminal blocks or equivalent facilities shall be provided for the main Meters and for the check Meters of each circuit. The test facilities shall be nearby the Meters involved.

5.3 Meters

The quantities defined in clause 4.1.1 shall be measured by both main and check Meters.

Active Energy Meters shall meet the requirements of BS EN 62053-22 Class 0.2S.

All Meters shall be set to the actual primary and secondary ratings of the measurement transformers and the actual ratios displayed on the display or nameplate of the Meter.

Active Energy Meters shall be configured such that the number of measuring elements is equal to or one less than the number of primary system conductors. These include the neutral conductor, and/or the earth conductor where system configurations enable the flow of zero sequence energy.

Reactive Energy Meters shall meet the Class 2.0 requirements of BS EN 62053-23.

All Meters shall be labelled or otherwise be readily identifiable in accordance with Appendix B.

All Meters shall include a non-volatile Meter Register of cumulative energy for each measured quantity. The Meter Register(s) shall not roll-over more than once within the normal Meter reading cycle.

Meters which provide data to separate Outstations shall for this purpose provide two outputs per measured quantity.

For Meters using electronic displays due account shall be taken of the obligations of the Central Data Collection Agent (CDCA) or other Data Collectors to obtain Meter readings.

Fusing shall be placed as close as practicable to the VT. In addition, means of isolation shall be provided locally for each Meter, any additional burden, and their associated test facilities in accordance with Appendix C.

5.4 Displays and Facilities for Registrant Information

5.4.1 Displays

The Metering Equipment shall display the following primary information (not necessarily simultaneously):

(i) Mandatory Displays:

a) Measured quantities as per clause 4.1.1;

b) Current time ("UTC") and date;

c) Measurement transformer ratios (see clause 5.3); and

d) Any compensation factor which has been applied for measurement transformer errors and/or system losses, where this is a constant factor[4] applied at security level 3 (i.e. where the Meter is combined with the display and/or Outstation).

Metering Equipment shall be capable of enabling the display of the following, as specified by the Registrant:

(ii) Display capabilities:

a) Maximum Demand (MD) for kW or MW as appropriate per programmable charging period i.e. monthly or statistical reviw period;

b) Maximum Demand (MD) for kVA or MVA as appropriate per programmable charging period i.e. monthly or statistical review period;

c) Twice the kWh advance or MWh advance as appropriate since the commencement of a current Demand Period (i.e. kW or MW rising demand);

d) Cumulative MD;

e) Number of MD resets; and

f) Multi-rate display sequence as specified by the Registrant with a minimum of 8 rates selectable over the calendar year.

[4] N.B. This excludes cases where a dynamic range of compensation factors have been applied.

MD shall be resettable at midnight of the last day of the charging period and for part chargeable period demands. If a manual reset button is provided then this shall be sealable.

5.4.2 Facilities

The Metering Equipment shall be capable of providing the following information locally to the Customer or Registrant configured to their requirements taking account of the measured quantities (see clause 4.1.1)[5]:

(i) For active energy in MWh or kWh as appropriate (Import and Export), reactive energy in Mvarh or kVArh as appropriate (Import and Export) – if volt-free contacts are used, then these should use a pulse rate at full load of at least 1000 per Settlement Period with a nominal duration of 80ms per pulse; and

(ii) A 30 minute reset pulse, and if volt-free contacts are used then this pulse should be within a tolerance of ±0.1% of the Demand Period from the volt-free contacts with a minimum duration of 80ms.

5.5 Outstation

Duplicate Outstation Systems shall be provided which can be interrogated by Settlement Instations using independent ~~e~~Communication ~~l~~Lines.

Where separate Outstations are provided these shall each store main and check Meter data for one or more circuits and where practicable shall be configured identically. Separate Outstations storing data from different circuits may be cascaded on to one ~~e~~Communication ~~l~~Line.

Metering Systems comprising Meters with integral Outstations need not store data from the associated main or check Meter providing that each Outstation has separate communications**.**

For Metering Systems located at Offshore Power Park Modules duplicate Outstation Systems with separate Communication Lines shall be provided. Main and check data shall be accessible by either of the separate Communication Lines. A single point of failure shall not prevent access to both main and check metering data.

The Outstation data shall be to a format and protocol approved by the Panel in accordance with BSCP601.

The Outstation shall have the ability to allow the metering data to be read by instations other than the Settlement Instation provided the requirements of Section 7 of this Code of Practice are satisfied.

[5] The requirements may be jointly met by the main and check Meters.

Facilities shall be provided to select a relevant demand period from one of the following values:-

30, 20, 15, 10 and 5 minutes with in each case one demand period ending on the hour.

Normally metering data will be collected by the Settlement Instations by a daily interrogation, but repeat collections of metering data shall be possible throughout the Outstation data storage period.

Outstations shall be fitted with an auxiliary terminal that provides for the Outstation's energisation for remote interrogation purposes. The supply to the auxiliary terminal shall be free of switches and secure, and may be provided from the measurement VT as long as it is separate from the potential measurement circuits.

Where a separate modem associated with the Outstation System is used, then it shall be provided with a secure supply separately fused. Alternatively, line or battery powered modem types may be used.

The Outstations shall provide an alarm output signal at a manned point in the event of a supply failure.

5.5.1 Data storage

Data storage facilities for metering data shall be provided as follows:-

(i) A storage capacity of 48 periods per day for a minimum of 10 days for all Demand Values

(ii) The stored Demand values shall be integer values of kW/MW or kvar/Mvar as appropriate, or pulse counts, and have a resolution of better than +0.1% (at full load);

(iii) The accuracy of the energy values derived from Demand Values shall be within +0.1% (at full load) of the amount of energy measured by the associated Meter;

(iv) The value of any energy measured in a Demand Period but not stored in that Demand Period shall be carried forward to the next Demand Period;

(v) Where a separate Outstation is used, cumulative register values shall be provided in the Outstation which can be set to match and increment with the Meter Registers;

(vi) In the event of an Outstation supply failure, the Outstation shall protect all data stored up to the time of the failure, and maintain the time accuracy in accordance with clause 5.5.2;

(vii) Partial Demand Values, those in which an Outstation supply failure and/or restoration occurs, and zero Demand Values associated with an Outstation supply failure, shall be marked so that the Settlement Instation can identify them;

(viii) To cater for continuous supply failures, the clock, calendar and all data shall be supported for a period of 10 days without an external supply connected;

(ix) Any "read" operation shall not delete or alter any stored metered data; and

(x) An Outstation shall provide any portion of the data stored upon request by an Instation.

5.5.2 Time Keeping

(i) The Outstation time shall be set to the Universal Time Clock (UTC) also known as Greenwich Mean Time (GMT). No switching between UTC and British Summer Time (BST) shall occur.

(ii) Time synchronisation of the Outstation shall only be performed by communication with the Settlement Instation.

(iii) The overall limits of error for the time keeping allowing for a failure to communicate with the Outstation for an extended period of 10 days shall be:-

a) the completion of each Demand Period shall be at a time which is within $\pm$ 10 seconds of UTC; and

b) the duration of each Demand period shall be within $\pm$ 0.1%, except where time synchronisation has occurred in a Demand Period.

5.5.3 Monitoring Facilities

Monitoring facilities shall be provided for each of the following conditions and shall be reported, tagged wherever possible to the relevant Demand Period(s), via the local interrogation facility:-

(i) Error in Outstation functionality;

(ii) Battery monitoring (where battery fitted); and

(iii) Interrogation port access which changes data.

In addition all of the above conditions shall be reported as, at minimum, a common alarm indication via the remote interrogation facility.

5.6 Communications

For integral Outstations: Outstation(s) shall accommodate both local and remote interrogation facilities, from separate ports.

To prevent unauthorised access to the data in the Metering Equipment a security scheme, as defined below and in Appendix D, shall be incorporated for both local and remote access. Separate security levels shall be provided for the following activities:

(i) Level 1 Password for:

Read-only access to the following metering data, which shall be transferrable on request during the interrogation process:

a) Outstation ID;

b) Demand Values as defined in clause 4.1.2;

c) Cumulative measured quantities as defined in clause 4.1.1;

d) Maximum Demand (MD) for kW/MW or kVA/MVA as appropriate per programmable charging period i.e. monthly or statistical review period;

e) Multi-rate cumulative Active Energy as specified by the Registrant;

f) Measurement transformer ratios, where appropriate (see clause 5.3);

g) Measurement transformer error correction factor and/or system loss factor where this is a constant factor applied to the entire dynamic range of the Meter and the Meter is combined with the display and/or Outstation;

h) Alarm indications; and

i) Outstation time and date.

(ii) Level 2 Password for:

a) Corrections to the time and/or date; and

b) Resetting of the MD.

(iii) Level 3 Password for:

Programming of:

a) Displays and facilities as defined in clause 5.4;

b) Measurement transformer ratios, as appropriate (see clause 5.3);

c) Measurement transformer error correction and/or system loss factor where this is a constant factor applied to the entire dynamic range of the Meter and the Meter is combined with the display and/or Outstation; and

d) Passwords for levels 1, 2 and 3.

In addition it shall be possible to read additional information within the Metering Equipment to enable the programmed information to be confirmed.

(iv) Level 4 Password for[6]:

a) Calibration of the Metering Equipment;

b) Setting the measurement transformer ratios, where appropriate (see clause 5.3);

c) Setting the transformer error correction and/or system loss factors where this is other than a single factor; and

d) Programming the level 3 Password and the level 4 Password if appropriate.

In addition to the functions specified for each level it shall be feasible to undertake the functions at the preceeding level(s). E.g. at level 3 it shall also be possible to carry out the functions specified at levels 1 and 2. This need not apply at level 4 when access is obtained via removing the cover. Different Passwords shall be utilised for each level, which shall only be circulated in accordance with the relevant BSC Procedure.

For separate Outstations: A Password shall be required to read or change any data.

5.6.1 Local Interrogation

An interrogation port shall be provided for each Outstation which preferably shall be an opto port to BS EN 62056-21, and with a serial protocol such as BS EN 62056-21, for the following purposes:-

(i) Commissioning, maintenance and fault finding;

(ii) Transfer of metering data and alarms; and

[6] These may be facilitated by the breaking of a seal.

(iii) Time setting.

5.6.2 Remote Interrogation

Remote interrogation shall be provided with error checking of the communications between the Outstation System and the Settlement Instation.

Interrogation of an Outstation shall be possible using one of the following media:-

(i) Switched telephone networks e.g. PSTN or CTN;

(ii) Public data networks e.g. PSN;

(iii) Radio data networks e.g. Paknet or any equivalent;

(iv) Customer's own network;

(v) Mains signalling / power line carrier;

(vi) Low power radio;

(vii) Satellite; or

(viii) Cable TV.

In addition any further media may be used as approved by the Panel.

The actual media employed shall be in accordance with the requirements of the CDCA for CVA Metering Systems and the Supplier for SVA Metering Systems.

The data shall be to a format and protocol approved by the Panel in accordance with BSCP601.

5.7 Sealing

All Metering Equipment shall be capable of being sealed in accordance with BSCP06.

6. ASSOCIATED FACILITIES

6.1 Interrogation Unit

The Operator may interrogate the Outstations using an Interrogation Unit (IU). The Interrogation Unit may be used for commissioning, maintenance/fault finding and when necessary the retrieval of stored metering data. The data retrieved by the Interrogation Unit shall be compatible with the Settlement Instation.

6.2 Additional Features

Additional features may be incorporated within or associated with the Metering Equipment provided but these shall not interfere with or endanger the operation of the Settlement process.

7. ACCESS TO DATA

Access to metering data shall be in accordance with the provisions of the Code and the BSC Procedures referred to therein. Such access must not interfere with or endanger the security of the data or the collection process for Settlement purposes.

Access to stored metering data in Outstations shall also be the right of the Registrant and any party who has the permission of the Registrant.

APPENDIX A DEFINED METERING POINTS

For transfers of electricity between the following parties the Defined Metering Point (DMP) shall be at one of the following locations:-

1. For transfers between a Transmission System operator and a single Licensed Distribution System Operator where no other Party(s) are connected to the busbar, the DMP shall be at the lower voltage side of the supergrid connected transformer.

2. For transfers between a Transmission System operator and a single Licensed Distribution System Operator where other Party(s) are connected to the busbar, the DMP shall be at the circuit connections to that Licensed Distribution System Operator.

3. For transfers between a Transmission System operator and more than one Licensed Distribution System Operator connected to the same busbar, the DMP shall be at the circuit connnections of each Licensed Distribution System Operator to such busbar.

4. For transfers between Licensed Distribution System Operators not including a connection to a Transmission System, the DMP shall be at the point of connection of the two Licensed Distribution System Operators.

5. For transfers between a Transmission System operator and Generating Plant, the DMP shall be at the high voltage side of the generator transformers and station transformer(s).

6. For transfers between a Licensed Distribution System Operator and Generating Plant, the DMP shall be at the point(s) of connection of the generating station to the Licensed Distribution System Operator.

7. For transfers between a Licensed Distribution System Operator and a Customer, the DMP shall be at the point of connection to the Distribution System of the Licensed Distribution System Operator.

8. For transfers between a Transmission System operator and a Customer, the DMP shall be at the point of connection to the Transmission System operator.

9. For transfers between a Transmission System operator and an External System the DMP shall be as follows:-

   (i) For the EdF link the busbar side of the busbar disconnectors at the Sellindge 400 kV Substation.

   (ii) For the Moyle Interconnector, the Convertor Station side of the L15 circuit breaker on the Coylton feeder at Auchencrosh Substation.

APPENDIX B LABELLING OF METERS FOR IMPORT AND EXPORT

A standard method of labelling Meters, test blocks, etc is necessary and based on the definitions for Import and Export the required labelling shall be as follows.

1 ACTIVE ENERGY

Meters or Meter Registers shall be labelled “Import” or “Export” according to the diagram “Figure 1”.

2 REACTIVE ENERGY

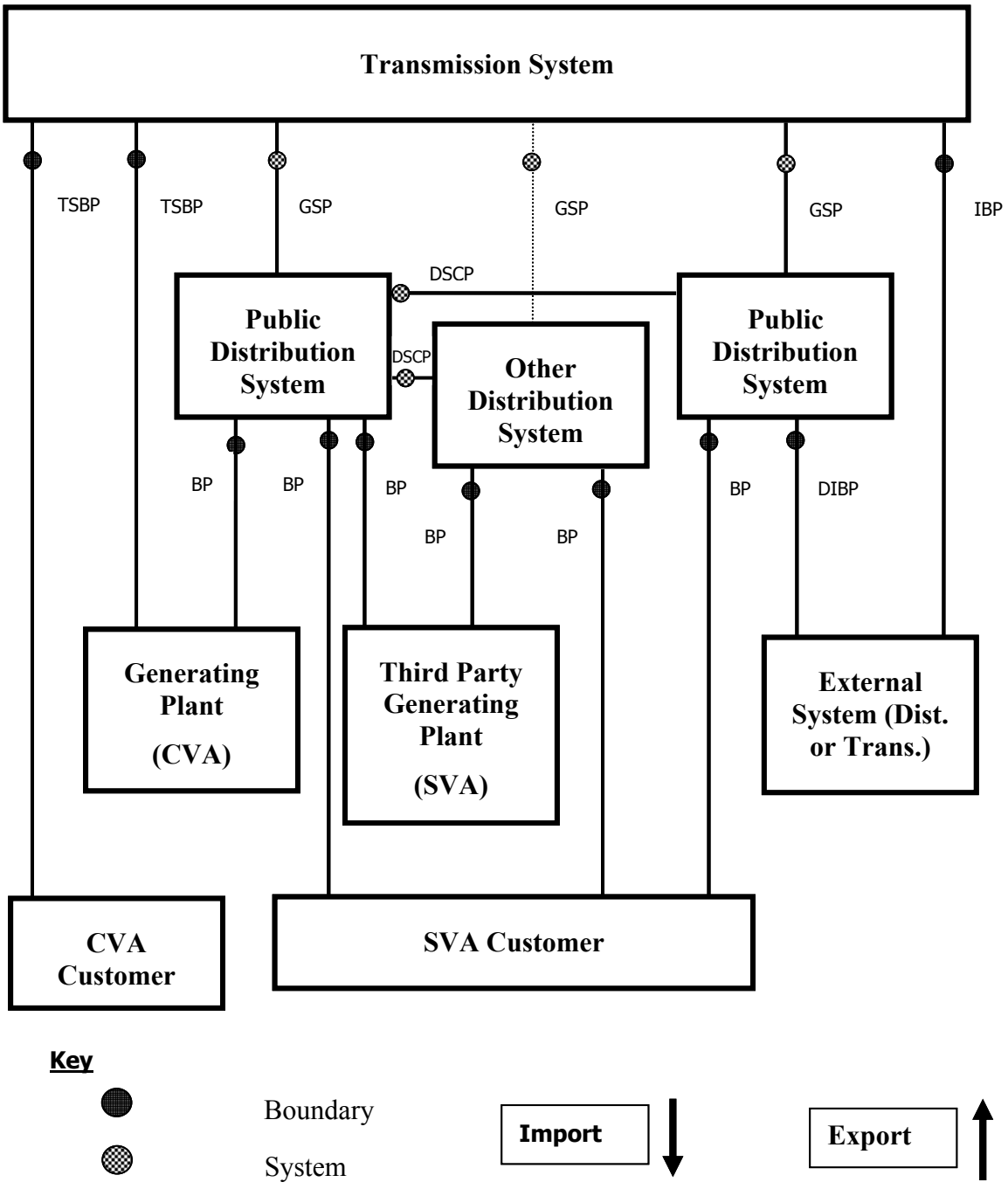
Within the context of this code the relationship between Active Energy and Reactive Energy can best be established by means of the power factor. The following table gives the relationship:-

Flow of Active Energy	Power Factor	Flow of Reactive Energy
Import	Lagging	Import
Import	Leading	Export
Import	Unity	Zero
Export	Lagging	Export
Export	Leading	Import
Export	Unity	Zero

Meters or Meter Registers for registering Import Reactive Energy should be labelled “Import” and those for registering Export Reactive Energy should be labelled “Export”.

APPENDIX B continued

FIGURE 1 IMPORT AND EXPORT ACTIVE ENERGY FLOWS CONVENTION



Import / Export Energy Flow Convention for the labelling of Meters
Import metering measures energy flows away from the Transmission System.
Export metering measures energy flows towards the Transmission System.
Energy flows between Distribution Systems is by bilateral agreement.

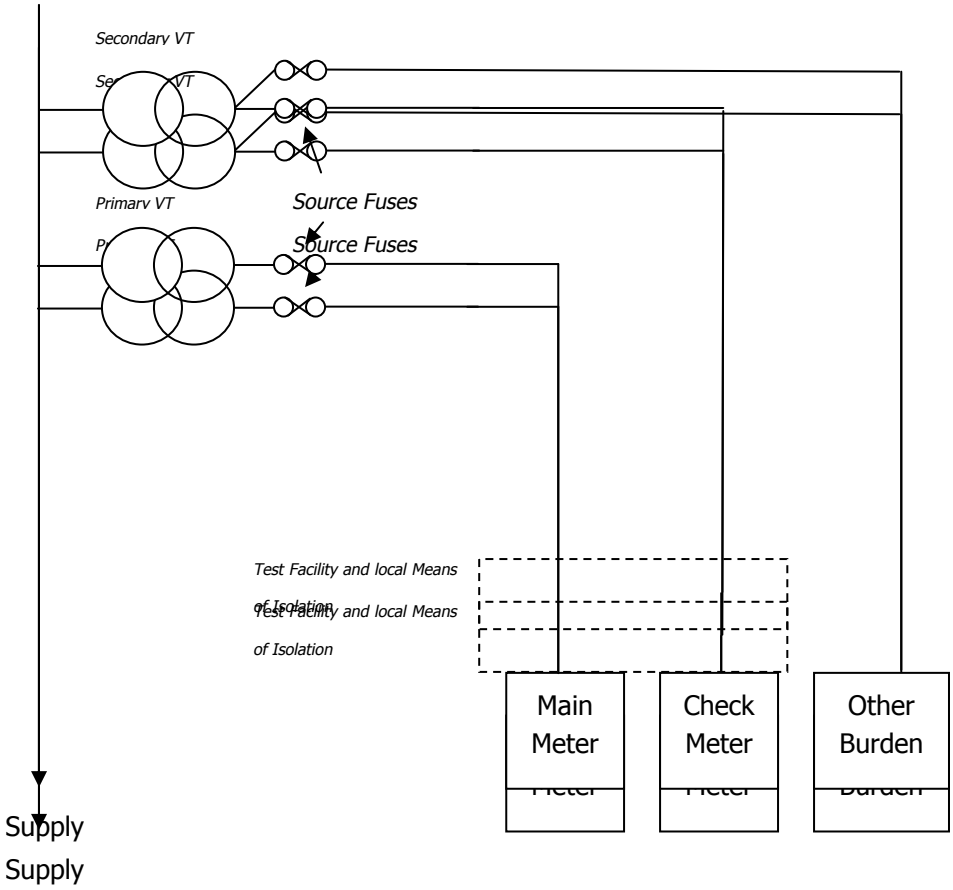
Key to abbreviations used in Import / Export Diagram

	Metering Point
BP	Boundary Point
DIBP	Distribution Interconnector Boundary Point
DSCP	Distribution System Connection Point
GSP	Grid Supply Point
IBP	Interconnector Boundary Point
SCP	System Connection Point
TSBP	Transmission System Boundary Point

APPENDIX C FUSING

The following diagram shows a typical arrangement for the fusing requirements of this Code of Practice. The diagram is non-exhaustive and is provided for reference only.

Figure 1: Fusing arrangements[7] [8].



Note:

The boundary between Meter Operator Equipment and the Transmission/Distribution System Operator is between the local means of isolation and the testing facilities.

[7] Check Meters and other burden may be supplied via an additional secondary winding of the primary VT.

[8] Isolation may be provided by the use of solid links or fuses and may be located either side of the test terminal block. Where fuses are to be used, the additional burden shall be accounted for.

APPENDIX D PASSWORDS

The Passwords specified in clause 5.6 shall be subject to the following additional requirements:

i. The communications protocol employed shall ensure that the Password offered determines the level of access to the data within the Metering Equipment.

ii. A counter to log the number of illegal attempts (i.e. Password comparison failures) to access Metering Equipment via the local and remote ports shall be incorporated into the log-on process. This counter shall reset to zero at every hour change (i.e. 0100, 0200 etc).

iii. If the counter reaches 7, then access is prohibited at all levels until the counter resets at the next hour change.

APPENDIX E GUIDANCE FOR THE USE OF MULTI CORE METERING CABLES

Multi core cables are predominantly used to provide CT and VT signals to the Meter. However, such arrangements may cause additional errors that are not readily apparent to the Metering System designer. This guidance provides information that should be considered when using multi core cables for metering, particularly if used over long cable runs.

Consideration shall be given to the cross sectional area of the conductors of multi core cables:

i. In CT circuits the cabling resistance is likely to represent an appreciable component of the CT burden and care should be taken to ensure that the CT overall burden is not exceeded;

ii. For the VT circuits, cabling and fuses introduce high volt drop errors. Fuses with a low current rating tend to have a relatively high resistance value and are variable from fuse to fuse. Careful selection of fuses, fuse holders and the doubling of cores can be used to mitigate these effects.

The proximity of CT and VT signals in multi core cables can cause errors due to capacitive coupling from the voltage to the current curcuits. The effect of this coupling is more prevalent at low loads with long cable runs, in particular with 1 amp rated CTs. One possible symptom of this condition is that the Meters may advance under no load conditions (circuit energised but with no load current). This coupling effect may be eliminated by careful allocation of cable core to function, or by running CT and VT signals in separate cables.

Balancing and Settlement Code

Code of Practice Two

CODE OF PRACTICE FOR THE METERING OF CIRCUITS WITH A RATED CAPACITY NOT EXCEEDING 100 MVA FOR SETTLEMENT PURPOSES.

Issue 4

Version 6.0

DATE: 5 November 2009

Code of Practice Two

CODE OF PRACTICE FOR THE METERING OF CIRCUITS WITH A RATED CAPACITY NOT EXCEEDING 100 MVA FOR SETTLEMENT PURPOSES.

1. Reference is made to the Balancing and Settlement Code for the Electricity Industry in Great Britain and, in particular, to the definition of "Code of Practice" in Annex X-1 thereof.

2. This is Code of Practice Two, Issue 4, Version 6.0

3. This Code of Practice shall apply to Metering Systems comprising Metering Equipment that are subject to the requirements of Section L of the Balancing and Settlement Code.

4. This Code of Practice is effective from 5 November 2009

5. This Code of Practice has been approved by the Panel.

AMENDMENT RECORD

ISSUE	DATE	VERSION	CHANGES	AUTHOR	APPROVED
Draft	18/3/93	0.03	Recommended to PEC	MSC	
1	15/4/93	1.00	Endorsed by PEC	CoP WG	
2	01/5/97	1.03	Amendments for 100kW Take-on	1998 Programme	
3	1998 Operational Date	1.05	Amended following review by Expert Group and internally.	1998 Programme (C A Team)	
3	Code Effective Date[1]	1.05	Re-badging of Code of Practice Two for the implementation of the Balancing and Settlement Code	BSCCo (Elexon Limited)	Panel 16/11/00 (Paper 07/003)
3	BETTA Effective Date	2.0	BETTA 6.3 Rebadging changes for the CVA Feb 05 Release	BSCCo	
4	23 February 2006	3.0	CP1051 changes for the February 06 Release	BSCCo	ISG/55/002
4	6 November 2008	4.0	CP1232 and CP1238 for the November 08 Release	BSCCo	ISG88/01 SVG88/02
4	25 June 2009	5.0	CP1264 for the June 09 Release	BSCCo	ISG94/01 SVG94/02
4	5 November 2009	6.0	CP1289	BSCCo	ISG101/01

[1] "Code Effective Date" means the date of the Framework Agreement.

CODE OF PRACTICE FOR THE METERING OF CIRCUITS WITH A RATED CAPACITY NOT EXCEEDING 100MVA FOR SETTLEMENT PURPOSES.

FOREWORD

This Code of Practice defines the minimum requirements for the Metering Equipment required for the measurement and recording of electricity transfers at Defined Metering Points where the rated circuit capacity does not exceed 100MVA.

For the purpose of this Code of Practice the rated circuit capacity in MVA shall be determined by the lowest rated primary plant (e.g. transformer rating, line rating, etc) of the circuit. The Metering Equipment provision and accuracy requirements shall anticipate any future up-rating consistent with the installed primary plant. The primary plant maximum continuous ratings shall be used in this assessment.

For the purpose of this Code of Practice, the use of summation current transformers shall not be permitted. The use of interposing current transformers is permitted provided the overall Metering System accuracy is maintained.

Where a material change to a Metering System takes place, then this Metering System must be modified to comply with the most recent version of this Code of Practice. Changes to a Metering System are considered to be material where they constitute a change to:

i. Swithchgear containing measurement transformers; and/or

ii. The primary plant associated with the Metering System i.e. the measurement transformers.

Where a Metering Dispensation applies, and where the Actual Metering Point is not at the Defined Metering Point, a material change affecting the Defined Metering Point may not affect the Metering System at the Actual Metering Point.

BSCCo shall retain copies of, inter alia, the Code of Practice together with copies of all documents referred to in them, in accordance with the provisions of the Balancing and Settlement Code (the Code).

1. SCOPE

This Code of Practice states the practices that shall be employed, and the facilities that shall be provided for the measurement and recording of the quantities required for Settlement purposes on each circuit where the rated capacity does not exceed 100MVA.

It derives force from the Code, and in particular the metering provisions (Section L), to which reference should be made. It should also be read in conjunction with any relevant BSC Procedures.

This Code of Practice does not contain the calibration, testing and commissioning requirements for Metering Equipment used for Settlement purposes. These requirements are detailed in Code of Practice Four - "Code of Practice for Calibration, Testing and Commissioning Requirements for Metering Equipment for Settlement Purposes".

Metering Dispensations from the requirements of this Code of Practice may be sought in accordance with the Code and BSCP32.

Meters and Outstations referred to in this Code of Practice shall only achieve successful compliance in respect of any testing detailed in this Code of Practice if the requirements set out in accordance with BSCP601 are also observed and successfully completed or the Registrant has been granted a valid Metering Dispensation covering any departure from the requirements as detailed in this Code of Practice.

In the event of an inconsistency between the provisions of this Code of Practice and the Code, the provisions of the Code shall prevail.

2. REFERENCES

The following documents are referred to in the text:-

BS EN 60044-3	Instrument transformers. Combined transformers
BS EN 62053-11	Electricity metering equipment (a.c.). Particular requirements. Electromechanical meters for active energy (classes 0.5, 1 and 2)
BS EN 62053-22	Electricity metering equipment (a.c.). Particular requirements. Static meters for active energy (classes 0.2 S and 0.5 S)
BS EN 62053-23	Electricity metering equipment (a.c.). Particular requirements. Static meters for reactive energy (classes 2 and 3)
BS EN 62056-21	Electricity metering. Data exchange for meter reading, tariff and load control. Direct local data exchange
BS 5685 Part 4	Specification for Class 3 Var-Hour Meters
IEC 60044-1	Instrument transformers. Current transformers
IEC 60044-2	Instrument transformers. Inductive voltage transformers
Balancing and Settlement Code	Definitions, Section X; Annex X-1 and Section L and BSC Procedures
Code of Practice Four	Code of Practice for Calibration, Testing and Commissioning Requirements for Metering Equipment for Settlement Purposes
BSC Procedures	BSCP06, BSCP32, BSCP601
Electricity Act 1989	Schedule 7 as amended by Schedule 1 to the Competition and Services (Utilities) Act 1992.

3. DEFINITIONS AND INTERPRETATIONS

Save as otherwise expressly provided herein, words and expressions used in this Code of Practice shall have the meanings attributed to them in the Code and are included for the purpose of clarification.

Note: * indicates definitions in the Code.

Note: † indicates definitions which supplement or complement those in the Code.

Note: ‡ indicates definitions specific to this Code of Practice

3.1 Active Energy *

Active Energy means the electrical energy produced, flowing or supplied by an electrical circuit during a time interval, being the integral with respect to time of the instantaneous Active Power, measured in units of watt-hours or standard multiples thereof.

3.2 Active Power *

Active Power means the product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof, that is:-

1,000 Watts = 1 kW

1,000 kW = 1 MW

3.3 Actual Metering Point ‡

Actual Metering Point means the physical location at which electricity is metered.

3.4 Apparent Energy ‡

Apparent Energy means the integral with respect to time of the Apparent Power.

3.5 Apparent Power ‡

Apparent Power means the product of voltage and current measured in units of voltamperes and standard multiples thereof, that is:-

1,000 VA = 1 kVA

1,000 kVA = 1 MVA

3.6 CTN ‡

CTN means the Electricity Supply Industry (ESI) corporate telephone network.

3.7 Communication Line

Communication Line means a line or link which is dedicated to an Outstation System and is identified by a unique number, e.g. CTN line number 123, PSTN line number 321 or IP address 555.

3.8~~7~~ CVA †

CVA means "Central Volume Allocation".

3.9~~8~~ CVA Customer †

CVA Customer means any customer, receiving electricity directly from the Transmission System, irrespective of from whom it is supplied.

3.10~~9~~ Defined Metering Point ‡

Defined Metering Point means the physical location at which the overall accuracy requirements as stated in this Code of Practice are to be met. The Defined Metering Points are identified in Appendix A.

3.11~~0~~ Demand Period ‡

Demand Period means the period over which Active Energy, Reactive Energy or Apparent Energy are integrated to produce Demand Values. For Settlement purposes, each Demand Period shall be of 30 minutes duration, one of which shall finish at 24:00 hours.

3.12~~1~~ Demand Values ‡

Demand Values means, expressed in MW, Mvar or MVA, twice the value of MWh, Mvarh or MVAh recorded during any Demand Period[2]. The Demand Values are half hour demands and these are identified by the time of the end of the Demand Period.

3.13~~2~~ electricity *

"electricity" means Active Energy and Reactive Energy.

3.14~~3~~ Export †

Export means, for the purposes of this Code of Practice, an electricity flow as indicated in Figure 1 of Appendix B.

3.15~~4~~ Import †

Import means, for the purposes of this Code of Practice, an electricity flow as indicated in Figure 1 of Appendix B.

3.16~~5~~ Interrogation Unit ‡

Interrogation Unit means a Hand Held Unit "HHU" (also known as Local Interrogation Unit "LIU") or portable computer which can enter Outstation parameters and extract information from the Outstation and store this for later retrieval.

[2] Please note that these Demand Values are for use with CVA Metering Systems. SVA Metering Systems shall use units a factor of 103 smaller than CVA e.g. kW rather than MW.

3.176 Maximum Aggregated Capacity ‡

The maximum aggregated capacity for multiple circuits shall be determined for:-

(i) Generator circuits, by the summation of the capacities of the lowest primary plant rating for each circuit.

(ii) Network or customer circuits all of equal rating, by multiplying the lowest primary plant rating of one circuit by one less than the number of circuits involved, e.g. number of circuits (n) = 3, factor = n - 1 = 2.

(iii) Network or customer circuits of different ratings, (all of which must be under 100 MVA) by summation of the lowest plant rating for each circuit ignoring the highest rated circuit e.g. 3 circuits rated at 45 MVA, 40 MVA, 35 MVA, rating = 75 MVA.

3.187 Meter *

Meter means a device for measuring Active Energy and/or Reactive Energy.

3.198 Metering Equipment *

Metering Equipment means Meters, measurement transformers (voltage, current and combination units), metering protection equipment including alarms, circuitry, their associated Communications Equipment and Outstations, and wiring.

3.2019 Meter Register ‡

Meter Register means a device, normally associated with a Meter, from which it is possible to obtain a reading of the amount of Active Energy, or the amount of Reactive Energy that has been supplied by a circuit.

3.210 Outstation *

Outstation means equipment which receives and stores data from a Meter(s), for the purposes, inter-alia, of transfer of that metering data the Central Data Collector Agent (CDCA) or Data Collector, as the case may be, and which may perform some processing before such transfer and may be in one or more separate units or may be integral with the Meter.

3.221 Outstation System ‡

Outstation System means one or more Outstations linked to a single communication line.

3.232 PARh Meter ‡

PARh Meter means a phase-advanced reactive hour (PARh) Meter which is used for obtaining Import and Export Reactive Energy from one integrating Meter. The Reactive Energy Demand values shall be calculated using a formula involving the PARh Meter and the associated Active Energy Meter Demand Values.

3.243 Password ‡

For Meters with integral Outstations: 'Password' means a string of characters of length no less than six characters and no more than twelve characters, where each character is a case insensitive or sensitive alpha character (A to Z) or a digit (0 to 9) or the underscore character (_). Passwords must have a minimum of 2,000,000 combinations, for example six characters if composed of any alphanumeric characters or eight characters if composed only of hexadecimal characters (0 to F). The characters of a hexadecimal password must be in upper case.

For separate Outstations: a Password may be described as above for integral Outstations or a single password of any format[3].

3.254 PSTN ‡

PSTN means the public switched telephone network.

3.265 Rated Measuring Current ‡

Rated Measuring Current means the rated primary current of the current transformers in primary plant used for the purposes of measurement.

3.276 Reactive Energy *

Reactive Energy means the integral with respect to time of the Reactive Power.

3.287 Reactive Power *

Reactive Power means the product of voltage and current and the sine of the phase angle between them measured in units of voltamperes reactive and standard multiples thereof.

3.298 Registrant *

Registrant means in relation to a Metering System, the person for the time being registered in CMRS or (as the case may be) SMRS in respect of that Metering System pursuant to Section K of the Balancing and Settlement Code.

3.3029 Settlement Instation ‡

Settlement Instation means a computer based system which collects or receives data on a routine basis from selected Outstation Systems by as Data Collector.

3.310 SVA †

SVA means "Supplier Volume Allocation".

3.321 SVA Customer *

SVA Customer means a person to whom electrical power is provided, whether or not that person is the provider of that electrical power; and where that electrical power is measured by a SVA Metering System.

[3] Meters separate from their Outstation and capable of external communications should have the same password requirements as for separate Outstations.

3.33 UTC *

UTC means Co-ordinated Universal Time which bears the same meaning as in the document Standard Frequency and Time Signal Emission, International Telecommunication Union - RTF.460 (ISBN92-61-05311-4) (colloquially referred to as Rugby Time).

4. MEASUREMENT CRITERIA

The following measured quantities and Demand Values are for use with CVA Metering Systems. SVA Metering Systems shall use units a factor of 10^3 smaller than CVA e.g. kWh rather than MWh.

4.1 Measured Quantities and Demand Values

4.1.1 Measured Quantities

For each separate circuit the following energy measurements are required for Settlement purposes:

(i) Import MWh *

(ii) Export MWh *

(iii) Import Mvarh

(iv) Export Mvarh

4.1.2 Demand Values

For each Demand Period for each circuit the following Demand Values shall be provided:

(i) Import MW *

(ii) Export MW *

(iii) Import Mvar

(iv) Export Mvar

* Import or Export metering need only be installed where a Party requires this measurement to meet system or plant conditions.

4.2 Accuracy Requirements

4.2.1 Overall Accuracy

The overall accuracy of the energy measurements at or referred to the Defined Metering Point shall at all times be within the limits of error as shown:-

(i) Active Energy

CONDITION	LIMIT OF ERRORS AT STATED SYSTEM POWER FACTOR	
Current expressed as a percentage of Rated Measuring Current	Power Factor	Limits of Error
120% to 10% inclusive	1	± 1.0%
Below 10% to 5%	1	± 1.5%
Below 5% to 1%	1	± 2.5%
120% to 10% inclusive	0.5 lag and 0.8 lead	± 2.0%

(ii) Reactive Energy

CONDITION	LIMIT OF ERRORS AT STATED SYSTEM POWER FACTOR	
Current expressed as a percentage of Rated Measuring Current	Power Factor	Limits of Error
120% to 10% inclusive	Zero	± 4.0%
120% to 20% inclusive	0.866 lag and 0.866 lead	± 5.0%

These limits of error for both (i) and (ii) above shall apply at the Reference Conditions defined in the appropriate Meter specification.

Evidence to verify that these overall accuracy requirements are met shall be available for inspection by either the Panel or the Technical Assurance Agent.

4.2.2 Compensation for Measurement Transformer Error

To achieve the overall accuracy requirements it may be necessary to compensate Meters for the errors of the measurement transformers and the associated leads to the Meters. Values of the compensation shall be recorded and evidence to justify the compensation criteria, including wherever possible test certificates, shall be available for inspection by either the Panel or the Technical Assurance Agent.

4.2.3 Compensation for Power Transformer and Line Losses

Where the Actual Metering Point and the Defined Metering Point do not coincide a Metering Dispensation shall be applied for and, where necessary, compensation for

power transformer and/or line losses shall be provided to meet the overall accuracy at the Defined Metering Point.

The compensation may be achieved in the Metering Equipment and in this event the applied values shall be recorded. Supporting evidence to justify the compensation criteria shall be available for inspection by either the Panel or the Technical Assurance Agent.

Alternatively, the compensation may be applied in the software of the relevant data aggregation system used for Settlement purposes. In this event the factors shall be passed to the appropriate agency and evidence to justify the compensation criteria shall be made available for inspection by either the Panel or the Technical Assurance Agent.

5. METERING EQUIPMENT CRITERIA

Although for clarity this Code of Practice identifies separate items of equipment, nothing in it prevents such items being combined to perform the same task provided the requirements of this Code of Practice are met.

Metering Equipment other than outdoor measurement transformers shall be accommodated in a clean and dry environment.

5.1 Measurement Transformers

For each circuit current transformers (CT) and voltage transformers (VT) shall meet the requirements set out in clauses 5.1.1 and 5.1.2.

Additionally, where a combined unit measurement transformer (VT & CT) is provided the 'Tests for Accuracy' as covered in BS EN 60044-3 covering mutual influence effects shall be met.

All measurement transformers shall be of a wound construction.

For Metering Systems that represent low burdens on measurement transformers, consideration shall be given as to whether that operating burden is within the operating range of the measurement transformers. In such cases, it may be necessary to add additional burden.

Guidance for the use of multi core cables is provided in Appendix E.

5.1.1 Current Transformers

A dedicated set of current transformers in accordance with IEC 60044-1 and with a minimum standard of accuracy to Class 0.2S (irrespective of the secondary current rating of the CTs) shall be provided solely for the Settlement Metering of each circuit. No other burden shall be connected to this dedicated set of current transformers. The main Meter shall always be connected to this dedicated set of current transformers. The check Meter may also be connected to this dedicated set of current transformers.

Alternatively the check Meter may be connected to another set of current transformers which shall be in accordance with IEC 60044-1 and with a minimum standard of accuracy to Class 0.2S. Other burdens may be connected to this other set of current

transformers provided that the Panel or Technical Assurance Agent is notified and that the overall accuracy requirements in clause 4.2.1 are met and evidence of the value of the additional burden shall be available for inspection by the Panel. The additional burden shall not be modified without prior notification to the Panel, and evidence of the value of the modified additional burden shall be available for inspection by either the Panel or Technical Assurance Agent.

CT test certificates showing errors at the overall working burden or at burdens which enable the working burden errors to be calculated shall be available for inspection by either the Panel or the Technical Assurance Agent.

The total burden on each current transformer shall not exceed the rated burden of such CT.

5.1.2 Voltage Transformers

Voltage transformer primary windings shall be connected to the circuit being measured for Settlement purposes and a dedicated secondary winding shall be provided for the main and check metering. The voltage transformer secondary winding shall be in accordance with IEC 60044-2 and with a minimum standard of accuracy to Class 0.5. Where a voltage transformer has other secondary windings these may be used for the check metering of that circuit and for other purposes provided the overall accuracy requirements in clause 4.2.1 are met and evidence of the value of the additional burden is available for inspection by either the Panel or the Technical Assurance Agent.

The additional burden shall not be modified without prior notification to the Panel, and evidence of the value of the modified additional burden shall be available for inspection by either the Panel or the Technical Assurance Agent.

A VT test certificate(s) showing errors at the overall working burden(s) or at burdens which enable the working burden errors to be calculated shall be available for inspection by either the Panel or the Technical Assurance Agent.

The total burden on each secondary winding of a VT shall not exceed the rated burden of such secondary winding.

5.1.3 Monitoring of Voltage Transformers

Where a common mode fault, such as a VT fuse failure, could cause incorrect voltages on both the main and check Meters, Meters combining integral Outstations shall provide for the data to be identified with an alarm indicating phase failure.

For separate Outstations, an alarm may be used which shall incorporate a time delay feature so as to avoid spurious operation. This alarm shall provide notification of a phase failure by the next Working Day at a point which is normally manned.

A spare channel on the Outstation or any other available means may be used to transmit the alarm.

5.1.4 Measurement Transformers Installed on Existing Circuits

Where circuits, other than those newly installed, are to be metered to this Code of Practice and where the installed measurement transformers do not comply fully with clauses 5.1.1 & 5.1.2, then such measurement transformers may be used providing the requirements in clauses 4.2.1 and 5.1.3 are met.

5.2 Testing Facilities

Separate testing facilities shall be provided for the main Meters and for the check Meters of each circuit, which enables such Meters to be routinely tested and/or changed safely with the circuit energised. The test facilities shall be nearby the Meters involved.

5.3 Meters

The Meters may be either static or induction disc types.

For each circuit main and check Active Energy Meters shall be supplied. These Meters shall meet the requirements of either BS EN 62053-22 Class 0.5S, or BS EN 62053-11 class 0.5 except where the overall accuracy as defined in Clause 4.2.1 is required in the range "Below 5% to 1%" of Rated Measuring Current. Subject to the agreement of the Panel or Registrant where system or plant conditions permit either the Import or Export Meters may be omitted.

All Meters shall be set to the actual primary and secondary ratings of the measurement transformers and the actual ratios displayed on the display or nameplate of the Meter.

Active Energy Meters provided for the metering of supplies to customers shall be in accordance with Schedule 7 of the Electricity Act 1989.

For each circuit only main Reactive Energy Meter(s) need be supplied. The Reactive Energy Meters shall meet the requirements of either BS EN 62053-23 Class 3.0 or BS 5685 Part 4.

For existing metering installations a Reactive Meter connected in a PARh Meter configuration may be retained.

Active Energy Meters shall be configured such that the number of measuring elements is equal to or one less than the number of primary system conductors. These include the neutral conductor, and/or the earth conductor where system configurations enable the flow of zero sequence energy.

All Meters shall be labelled or otherwise be readily identifiable in accordance with Appendix B.

All Meters shall include a non-volatile Meter Register of cumulative energy for each measured quantity. The Meter Register(s) shall not roll-over more than once within the normal Meter reading cycle.

Meters which provide data to separate Outstations shall for this purpose provide an output per measured quantity.

For Meters using electronic displays due account shall be given to the obligations of the Central Data Collection Agent (CDCA) or other Data Collectors to obtain Meter readings. For example, where a Metering System is employed on multiple circuits, a Voltage Selector Relay or other similar method should be used to maintain the Meter display in the event of a circuit being de-energised where this is reasonably practical.

Fusing shall be placed as close as practicable to the VT. In addition, means of isolation shall be provided locally for each Meter, any additional burden and their associated test facilities in accordance with Appendix C.

5.4 Displays and Facilities for Registrant or Supplier Information

5.4.1 Displays

The Metering Equipment shall display the following primary information (not necessarily simultaneously):

(i) Mandatory Displays

a) Measured quantities as per clause 4.1.1;

b) Current time ("UTC") and date;

c) Measurement transformer ratios (see clause 5.3); and

d) Any compensation factor which has been applied for measurement transformer errors and/or system losses, where this is a constant factor[4] applied at security level 3 (i.e. where the Meter is combined with the display and/or Outstation).

Metering Equipment shall also be capable of displaying the following information, as specified by the Registrant.

(ii) Display capabilities

a) Maximum Demand (MD) for kW or MW as appropriate per programmable charging period i.e. monthly or statistical review period;

b) Maximum Demand (MD) for kVA or MVA as appropriate per programmable charging period i.e. monthly or statistical review period;

c) Twice the kWh advance or MWh advance as appropriate since the commencement of a current Demand Period (i.e. kW or MW rising demand);

d) Twice the kVAh advance or MVAh advance as appropriate since the commencement of a current Demand Period (i.e. kVA or MVA riding demand);

e) Cumulative MD;

[4] N.B. This excludes cases where a dynamic range of compensation factors have been applied.

f) Number of resets; and

g) Multi-rate display sequence as specified by the Registrant with a minimum of 8 rates selectable over the calendar year

MD shall be resettable at midnight of the last day of the charging period and for part chargeable period demands. If a manual reset button is provided then this shall be sealable.

5.4.2 Facilities

The Metering Equipment shall be capable of providing the following information locally to the Customer or Registrant configured to their requirements taking account of the measured quantities (see clause 4.1.1):

(i) For Active energy in MWh or kWh as appropriate (Import and Export), reactive energy in Mvarh or kVArh as appropriate (Import and Export) – if volt-free contacts are used, then these should use a pulse rate at full load of at least 1000 per Settlement Period with a nominal duration of 80ms per pulse; and

(ii) A 30 minute reset pulse, and if volt-free contacts are used then this pulse should be within a tolerance of ±0.1% of the Demand Period from the volt-free contacts with a minimum duration of 80ms.

5.5 Outstation

One Outstation System shall be provided which can be interrogated by Settlement Instations. The Outstation system shall comprise either a single separate Outstation or the use of Meters with integral Outstations (i.e. a main or check Meter storing its own data).

Where one or more separate Outstations are provided each Outstation shall store the main and check Meter data for one or more circuits up to a Maximum Aggregated Capacity of 100 MVA. Separate Outstations storing data from a number of different circuits may be cascaded on to one ~~e~~Communication ~~l~~Line.

Metering Systems comprising Meters with integral Outstations need not store data from the associated main or check Meter providing that each Outstation has separate communications.

For Metering Systems located at Offshore Power Park Modules duplicate Outstation Systems with separate Communication Lines shall be provided. Main and check data shall be accessible by either of the separate Communication Lines. A single point of failure shall not prevent access to both main and check metering data.

The Outstation data shall be to a format and protocol approved by the Panel in accordance with BSCP601.

The Outstation shall have the ability to allow the metering data to be read by instations other than the Settlement Instation provided the requirements of Section 7 of this Code of Practice are satisfied.

Facilities shall be provided to select a relevant demand period from one of the following values:-

30, 20, 15, 10 and 5 minutes with in each case one demand period ending on the hour.

Normally metering data will be collected by the Settlement Instations by a daily interrogation, but repeat collections of metering data shall be possible throughout the Outstation data storage period.

Outstations, that are not exclusive to one circuit, shall be fitted with an auxiliary terminal that provides for the Outstation's energisation for remote interrogation purposes. The supply to the auxiliary terminal shall be free of switches and secure, and may be provided from the measurement VT as long as it is separate from the potential measurement circuits at source.

Where a separate modem associated with the Outstation System is used, then it shall be provided with a separately fused supply either from a secure supply or from a measurement VT. Alternatively, line or battery powered modem types may be used.

Where a measurement VT source is used and the Outstation System is storing data for more than one circuit, a VT selection relay scheme involving each circuit shall be provided.

Preferably the Outstation shall be able to continue all normal functions for a period of 120 hours after a supply failure. Outstations not providing this facility must in the event of a supply failure transmit an alarm signal to a manned point.

The Outstation shall not convert PARh metering data to vars.

5.5.1 Data Storage

Data storage facilities for metering data shall be provided as follows:-

(i) A storage capacity of 48 periods per day for a minimum of 10 days for all Demand Values.

(ii) The stored Demand Values shall be integer values of kW/MW or kvar/Mvar as appropriate, or pulse counts, and have a resolution of better than ±0.1% (at full load);

(iii) The accuracy of the energy values derived from Demand Values shall be within ±0.1% (at full load) of the amount of energy measured by the associated Meter;

(iv) The value of any energy measured in a Demand Period but not stored in that Demand Period shall be carried forward to the next Demand Period;

(v) Where a separate Outstation is used, cumulative register values shall be provided in the Outstation which can be set to match and increment with the Meter Registers;

(vi) In the event of an Outstation supply failure, the Outstation shall protect all data stored up to the time of the failure, and maintain the time accuracy in accordance with clause 5.5.2;

(vii) Partial Demand Values, those in which an Outstation supply failure and/or restoration occurs, and zero Demand Values associated with an Outstation supply failure, shall be marked so that the Settlement Instation can identify them;

(viii) To cater for continuous supply failures, the clock, calendar and all data shall be supported for a period of 10 days without an external supply connected;

(ix) Any "read" operation shall not delete or alter any stored metered data; and

(x) An Outstation shall provide all of the metered data stored from the commencement of any specified date upon request by the Settlement Instation.

5.5.2 Time Keeping

(i) The Outstation time shall be set to Co-ordinated Universal Time (UTC). No switching between UTC and British Summer Time (BST) shall occur for Settlements data storage requirements.

(ii) Time synchronisation of the Outstation shall only be performed by communication with the Settlement Instation.

(iii) The overall limits of error for the time keeping allowing for a failure to communicate with the Outstation for an extended period of 10 days shall be:-

a) the completion of each Demand Period shall be at a time which is within ± 10 seconds of UTC; and

b) the duration of each Demand Period shall be within ± 0.1%, except where time synchronisation has occurred in a Demand Period.

5.5.3 Monitoring Facilities

Monitoring facilities shall be provided for each of the following conditions and shall be reported, tagged wherever possible to the relevant Demand Period(s), via the local interrogation facility:-

(i) Error in Outstation functionality;

(ii) Battery monitoring (where battery fitted); and

(iii) Interrogation port access which changes data.

In addition all of the above conditions shall be reported as, at minimum, a common alarm indication via the remote interrogation facility.

5.6 Communications

For integral Outstations: Outstation(s) shall provide both local and remote interrogation facilities, from separate ports.

To prevent unauthorised access to the data in the Metering Equipment a security scheme, as defined below and in Appendix D, shall be incorporated for both local and remote access. Separate security levels shall be provided for the following activities:

(i) Level 1 Password for:

Read-only access to the following metering data, which shall be transferable on request during the interrogation process:

a) Outstation ID;

b) Demand Values as defined in clause 4.1.2;

c) Cumulative measured quantities as defined in clause 4.1.1;

d) Maximum Demand (MD) for kW/MW or kVA/MVA as appropriate (as defined by the Registrant) per programmable charging period i.e. monthly or statistical review period;

e) Multi-rate cumulative Active Energy as specified by the Registrant;

f) Measurement transformer ratios, where appropriate (see clause 5.3)

g) Measurement transformer error correction factor and/or system loss factor, where this is a constant factor applied to the entire dynamic range of the Meter and the Meter is combined with the display and/or Outstation;

h) Alarm indications; and

i) Outstation time and date.

(ii) Level 2 Password for:

a) Corrections to Outstation time and/or date; and

b) Resetting of the MD

(iii) Level 3 Password for:

Programming of:

a) The Displays and Facilities as defined in clause 5.4;

b) Measurement transformer ratios, as appropriate (see clause 5.3);

c) Measurement transformer error correction factor and/or system loss factor, where this is a constant factor applied to the entire dynamic

range of the Meter and the Meter is combined with the display and/or Outstation; and

d) The Passwords for levels 1, 2 and 3;

In addition it shall be possible to read additional information within the Metering Equipment to enable the programmed information to be confirmed.

(iv) Level 4 Password for[5]:

a) Calibration of the Metering Equipment;

b) Setting the measurement transformer ratios, where appropriate (see clause 5.3);

c) Setting the measurement transformer error correction and/or system loss factors where this is other than a single factor; and

d) Programming the level 3 Password and the level 4 Password, if appropriate.

In addition to the functions specified for each level it shall be feasible to undertake functions at the preceding level(s). E.g. at level 3 it shall also be possible to carry out the functions specified at levels 1 and 2. This need not apply at level 4 when access is obtained via removing the cover. Different Passwords shall be utilised for each level, which shall only be circulated in accordance with the relevant BSC Procedure.

For separate Outstations: A Password shall be required to read or change any data.

5.6.1 Local Interrogation

An interrogation port shall be provided for each Outstation which preferably shall be an opto port to BS EN 62056-21, and with a serial protocol such as BS EN 62056-21, for the following purposes:-

(i) Commissioning, maintenance and fault finding;

(ii) Transfer of metering data and alarms; and

(iii) Time setting.

5.6.2 Remote Interrogation

Remote interrogation facilities shall be provided with error checking of the communications between the Outstation System and the Settlement Instation.

Interrogation of an Outstation shall be possible using one of the following media:

(i) Switched telephone networks e.g. PSTN or CTN;

(ii) Public data networks e.g. PSN;

(iii) Radio data networks e.g. Paknet or any equivalent;

[5] These may be facilitated by the breaking of a seal.

(iv) Customer own network;

(v) Mains signalling / power line carrier;

(vi) Low power radio;

(vii) Satellite; or

(viii) Cable TV.

In addition any further media may be used as approved by the Panel.

The actual media employed shall be in accordance with the requirements of the CDCA for CVA Metering Systems and the Supplier for SVA Metering Systems.

The data shall be to a format and protocol approved by the Panel in accordance with BSCP601.

5.7 Sealing

All SVA Metering Equipment shall be sealed in accordance with Appendix 8 and 9 of the Meter Operator Code of Practice Agreement[6].

All CVA Metering Equipment shall be capable of being sealed in accordance with BSCP06.

6. ASSOCIATED FACILITIES

6.1 Interrogation Unit

The Operator may interrogate the Outstations using an Interrogation Unit (IU). The Interrogation Unit may be used for programming, commissioning, maintenance/fault finding and when necessary the retrieval of stored metering data. The data retrieved by the Interrogation Unit shall be compatible with the Settlement Instation.

6.2 Additional Features

Additional features may be incorporated within or associated with the Metering Equipment provided but these shall not interfere with or endanger the operation of the Settlement process.

7. ACCESS TO DATA

Access to metering data shall be in accordance with the provisions of the Code and the BSC Procedures referred to therein. Such access must not interfere with or endanger the security of the data or the collection process for Settlement purposes.

Access to stored metering data in Outstations shall also be the right of the Registrant and any party who has the permission of the Registrant.

[6] The Meter Operator Code of Practice Agreement is a voluntary agreement between Public Distribution System Operators and Meter Operator Agents.

APPENDIX A DEFINED METERING POINTS

For transfers of electricity between the following parties the Defined Metering Point (DMP) shall be at one of the following locations:-

1. For transfers between a Transmission System operator and a single Licensed Distribution System Operator where no other Party(s) are connected to the busbar, the DMP shall be at the lower voltage side of the supergrid connected transformer.

2. For transfers between a Transmission System operator and a single Licensed Distribution System Operator where other Party(s) are connected to the busbar, the DMP shall be at the circuit connections to that Licensed Distribution System Operator.

3. For transfers between a Transmission System operator and more than one Licensed Distribution System Operator connected to the same busbar, the DMP shall be at the circuit connections of each Licensed Distribution System Operator to such busbar.

4. For transfers between Licensed Distribution System Operators not including a connection to the Transmission System, the DMP shall be at the point of connection of the two Licensed Distribution System Operators.

5. For transfers between a Transmission System operator and Generating Plant, the DMP shall be at the high voltage side of the generator transformers and station transformer(s).

6. For transfers between a Licensed Distribution System Operator and Generating Plant, the DMP shall be at the point(s) of connection of the generating station to the Licensed Distribution System Operator.

7. For transfers between a Licensed Distribution System Operator and a Customer, the DMP shall be at the point of connection to the Licensed Distribution System Operator.

8. For transfers between a Transmission System operator and a Customer, the DMP shall be at the point of connection to the Transmission System operator.

9. For transfers between a Transmission System and an External System the DMP shall be as follows:-

(i) For the EdF link the busbar side of the busbar disconnectors at the Sellindge 400 kV Substation.

(ii) For the Moyle Interconnector, the Convertor Station side of the L15 circuit breaker on the Coylton feeder at Auchencrosh Substation.

APPENDIX B LABELLING OF METERS FOR IMPORT AND EXPORT

1 A standard method of labelling Meters, test blocks, etc is necessary and based on the definitions for Import and Export the required labelling shall be as follows.

2 ACTIVE ENERGY

Meters or Meter Registers shall be labelled "Import" or "Export" according to the diagram "Figure 1".

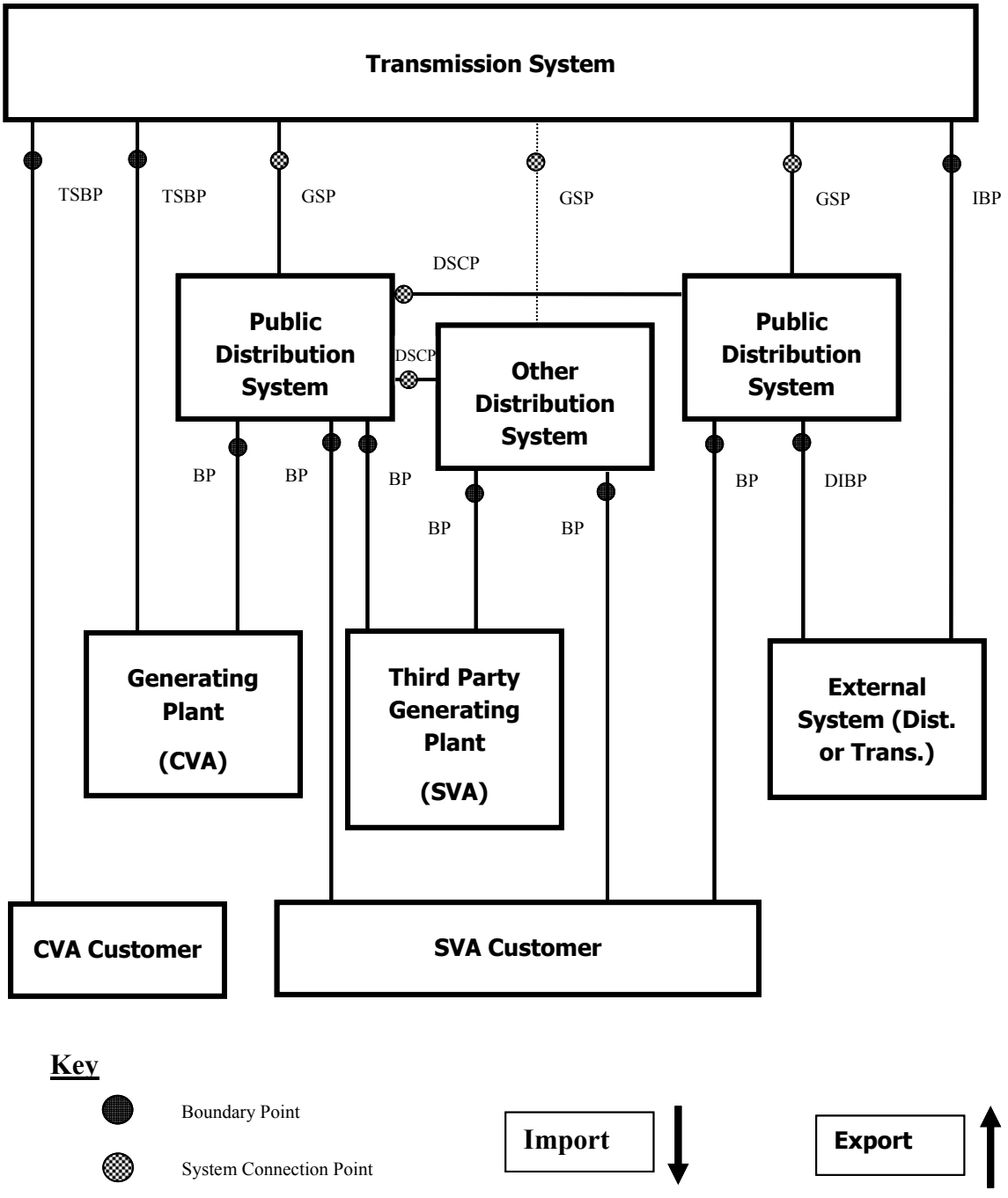
3 REACTIVE ENERGY

Within the context of this code the relationship between Active Energy and Reactive Energy can best be established by means of the power factor. The following table gives the relationship:-

Flow of Active Energy	Power Factor	Flow of Reactive Energy
Import	Lagging	Import
Import	Leading	Export
Import	Unity	Zero
Export	Lagging	Export
Export	Leading	Import
Export	Unity	Zero

Meters or Meter Registers for registering Import Reactive Energy should be labelled "Import" and those for registering Export Reactive Energy should be labelled "Export".

FIGURE 1 IMPORT AND EXPORT ACTIVE ENERGY FLOWS CONVENTION



Import / Export Energy Flow Convention for the labelling of Meters
Import metering measures energy flows away from the Transmission System.
Export metering measures energy flows towards the Transmission System.
Energy flows between Distribution Systems is by bilateral agreement.

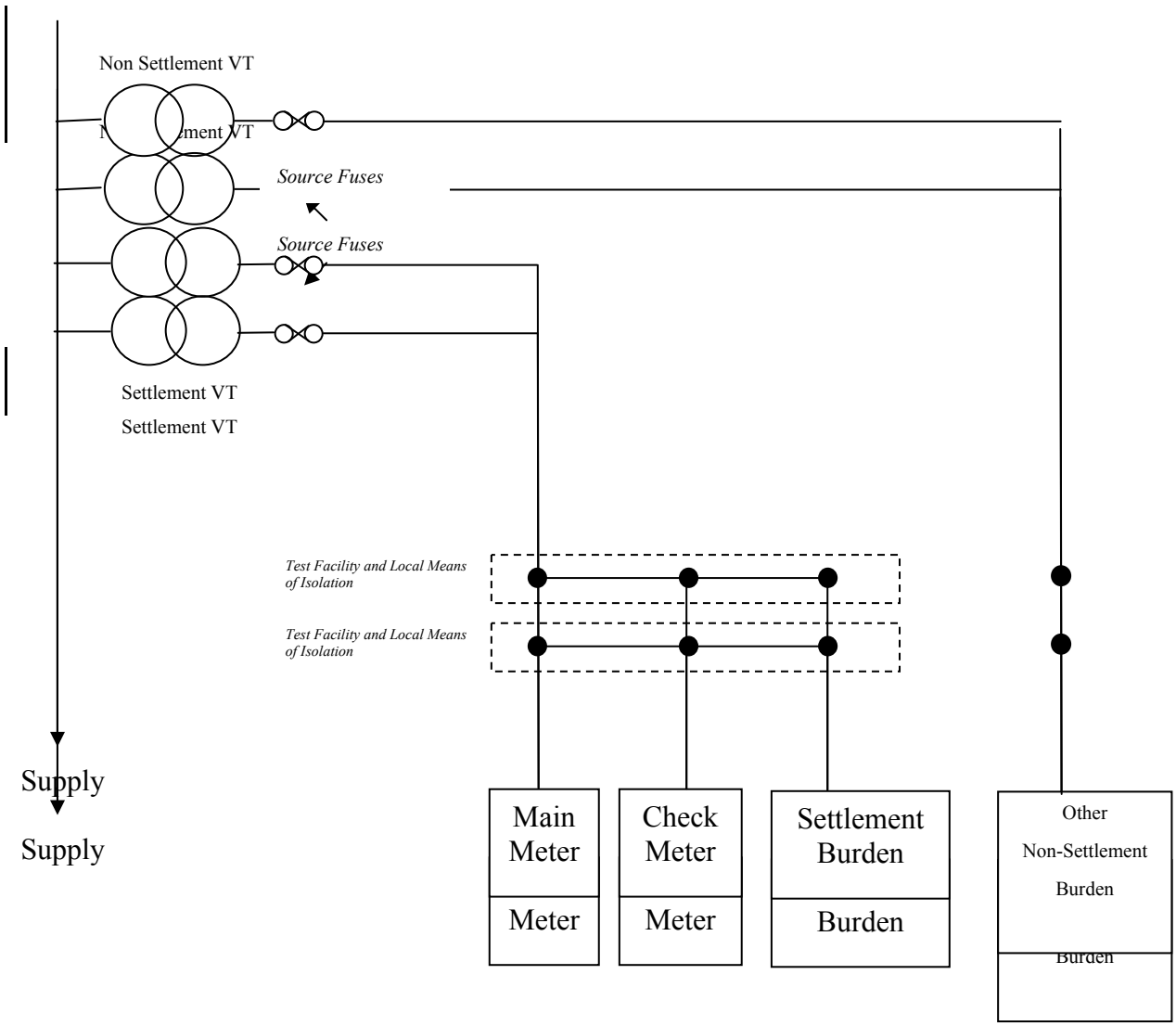
Key to abbreviations used in Import / Export Diagram

	Metering Point
BP	Boundary Point
DIBP	Distribution Interconnector Boundary Point
DSCP	Distribution System Connection Point
GSP	Grid Supply Point
IBP	Interconnector Boundary Point
SCP	System Connection Point
TSBP	Transmission System Boundary Point

APPENDIX C FUSING

The following diagrams show typical arrangements for the fusing requirements of this Code of Practice. The diagrams are non-exhaustive and are provided for reference only.

Figure 1: Fusing arrangements for cable runs of less than 30 metres distance between source fusing and local means of isolation[7] [8].



Note:

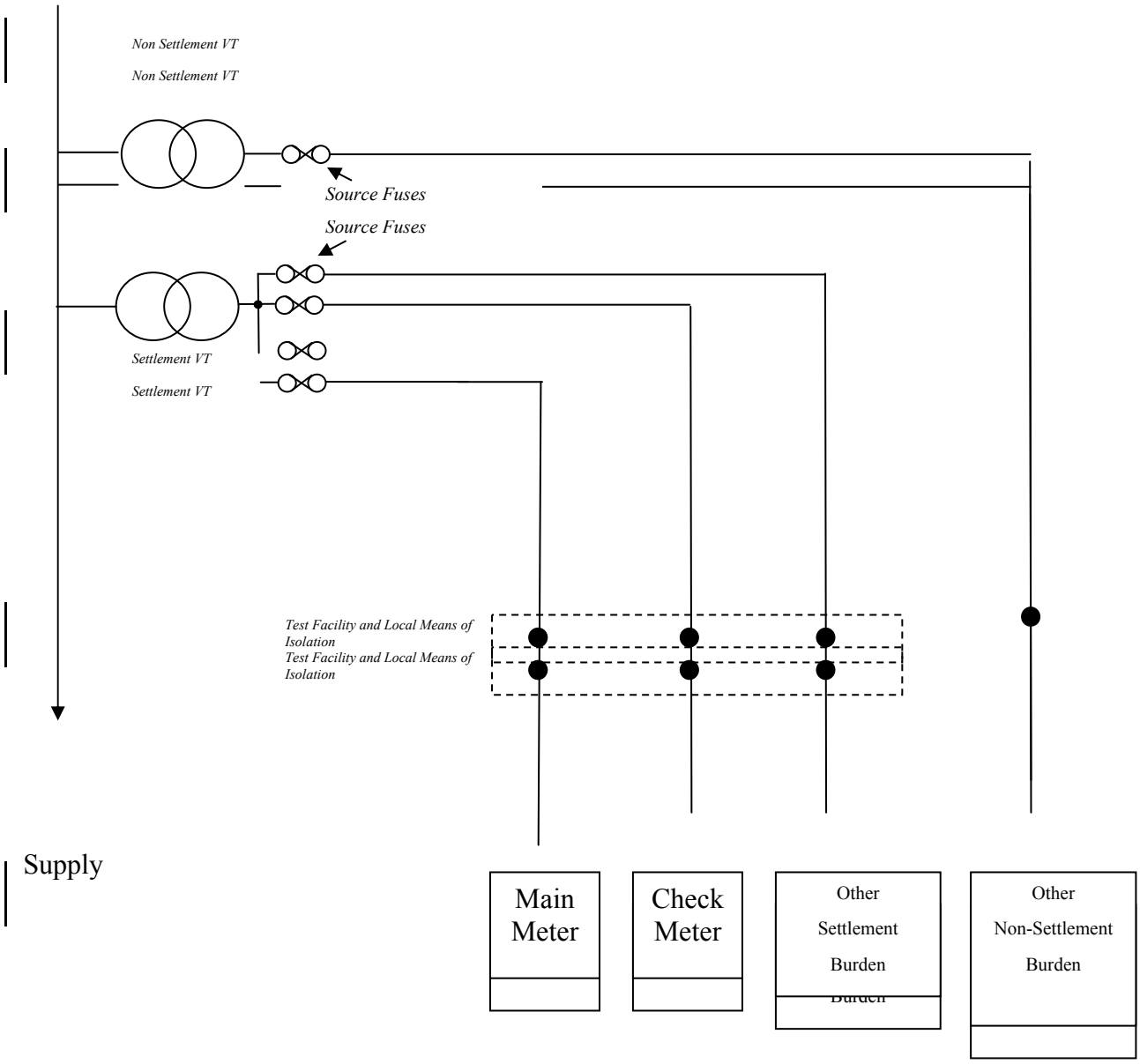
Source fusing and local means of isolation shall include the use of solid links in the potential return conductor.

The boundary between Meter Operator Equipment and the Transmission/Distribution System Operator is between the local means of isolation and the testing facilities.

[7] Isolation may be provided by the use of solid links or fuses and may be placed on either side of the test terminal block. Where fuses are to be used, the additional burden shall be accounted for.

[8] Check Meters and other burden may be supplied via an additional secondary winding of the VT

Figure 2: Fusing arrangements for cable runs of more than 30 metres distance between source fusing and local means of isolation[9] [10].



[9] Local isolation may be provided by the use of solid links or fuses and may be placed on either side of the test terminal block. Where fuses are to be used, the additional burden shall be accounted for.

[10] Check Meters and other burden may be supplied via an additional secondary winding of the VT.

APPENDIX D PASSWORDS

The Passwords specified in clause 5.6 shall be subject to the following additional requirements:

i. The communications protocol employed shall ensure that the Password offered determines the level of access to the data within the Metering Equipment.

ii. A counter to log the number of illegal attempts (i.e. Password comparison failures) to access Metering Equipment via the local and remote ports shall be incorporated into the log-on process. This counter shall reset to zero at every hour change (i.e. 0100, 0200, etc).

iii. If the counter reaches 7, then access is prohibited at all levels until the counter resets at the next hour change.

APPENDIX E GUIDANCE FOR THE USE OF MULTI CORE METERING CABLES

Multi core cables are predominantly used to provide CT and VT signals to the Meter. However such arrangements may cause additional errors that are not readily apparent to the Metering System designer. This guidance provides information that should be considered when using multi core cables for metering, particularly if used over long cable runs.

Consideration shall be given to the cross sectional area of the conductors of multi core cables:

i. In CT circuits the cabling resistance is likely to represent an appreciable component of the CT burden and care should be taken to ensure that the CT overall burden is not exceeded;

ii. For the VT circuits, cabling and fuses introduce volt drop errors. Fuses with a low current rating tend to have a relatively high resistance value and are variable from fuse to fuse. Careful selection of fuses, fuse holders and the doubling of cores can be used to mitigate these effects.

The proximity of CT and VT signals in multi-core cables can cause errors due to capacitive coupling from the voltage to the current circuits. The effect of this coupling is more prevalent at low loads and with long cable runs, in particular with 1 amp rated CTs. One possible symptom of this condition is that the Meters may advance under no load conditions (circuit energised but with no load current). This coupling effect may be eliminated by careful allocation of cable core to function, or by running CT and VT signals in separate cables.

3 Interface and Timetable Information

Meter Advance Reconciliation

3.1 Meter readings shall be scheduled according to the type of Metering System:

- For Meters with integral Outstations that provide a cumulative reading of the prime Meter register equivalent to the total consumption or production of that Meter, the CDCA shall carry out an in-house daily Meter Advance Reconciliation (MAR) using the period half hour data and associated cumulative register data collected as part of the routine dial up process. The tolerance for this MAR shall be ±5%.[1] The CDCA shall schedule a site visit to carry out an MAR and visual check every 12 months.
- For Meters with integral Outstations that do not provide a cumulative reading of the prime Meter register equivalent to the total consumption or production of that Meter, the CDCA shall schedule a site visit to carry out an MAR and visual check every 6 months..
- For Meters wi~~l~~th external Outstations, the CDCA shall schedule a site visit to carry out an MAR and visual check every 3 months.
- For Meters with external Outstations which are located at Offshore Power Park Modules, the CDCA shall schedule an initial site visit to carry out a MAR and visual check within 3 months of the Metering Equipment becoming registered in CMRS. Thereafter site visits will be conducted every 12 months.

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.1.1	Annually	Notification of the Meter reading schedule for a 12 month period.	CDCA	Registrant MOA	Date and site(s) for Meter reading	Fax / Post / Email
3.1.2	At least 5WD before the Meter reading	Confirmation of particular Meter reading(s) arrangements.	CDCA	Registrant MOA	Date and site(s) for Meter reading	Fax / Post / Email

[1] If the daily MAR exceeds this tolerance, and the CDCA considers it to be a significant error, then the CDCA shall report it to the registrant as a metering fault.

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.1.3	As scheduled.	Record the physical Meter reading(s), date and time in the presence of the Registrant's representative, if attending. Where the Meter has an integral outstation and the facility for electronic local interrogation, the CDCA may utilise a LIU for this purpose.	CDCA		Signed record of Universal Meter Reading Sheet (BSCP05/4.1) Or LIU data BSCP05/4.1 requires any witness who signs to be an authorised person. An authorised person must be registered under BSCP38 by the Party.	
3.1.4	At the time of the Meter reading	Carry out a visual inspection of the Metering Equipment as specified in Appendix 4.3 and complete Form BSCP05/4.3.	CDCA		BSCP05/4.3 CDCA Metering System Visual Inspection	
3.1.5	Within 5WD of Meter reading	Copy the completed Meter reading sheets to the Registrant and MOA and retain originals.	CDCA	Registrant(s) MOA	Signed record of Universal Meter Reading Sheet (BSCP05/4.1)	Post / Electronic
3.1.6	Within 5WD of Meter reading	Copy the completed CDCA Metering System Status Report to BSCCo.	CDCA	BSCCo	BSCP05/4.3 CDCA Metering System Visual Inspection	Fax / Post / Email
3.1.7	Within 5WD of Meter reading	Notify Registrant and MOA of any metering defects that they should remedy.	CDCA	Registrant MOA	Details of any metering defects as a result of the visual inspection carried out at the time of the Meter reading.	Fax / Post / Email

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.1.8	Within 5WD of Meter reading	Perform MAR	CDCA		BSCP05/4.1, Universal Meter Reading Sheet	Internal Process
3.1.9	Within 15WD of Meter reading	Notify the Registrant and MOA of the MAR result(s) and request an explanation of discrepancies greater than ±0.1%.	CDCA	Registrant(s)[2], MOA (and if appropriate LDSO)	MAR result and explanation of discrepancy, as appropriate.	Fax / Post / Email
3.1.10	Within 5WD of 3.1.9	Provide explanation of any discrepancies greater than ±0.1%.	MOA	CDCA	Explanation of any discrepancies greater than ±0.1%.	Fax / Post / Email
3.1.11	Within 15WD of Meter reading	Notify the BSCCo of the MAR results where there is a discrepancy greater than ±0.1%	CDCA	BSCCo	MAR error result	Fax / Post / Email
3.1.12	Within 20WD of Meter reading.	Discuss possible erroneous values resolving, if possible, any apparent discrepancy.	MOA	CDCA	Explanation of discrepancy	Fax / Post / Email
3.1.13	Within 21 WD of Meter reading	Submit corrected data to the following Volume Allocation Runs unless the discrepancy is not yet resolved. Once resolved submit corrected data or, failing this, proceed to 3.1.14	CDCA			Internal Process

[2] In the case where difference metering is used to determine a Registrant's Import / Export, the non-metered Registrant shall be provided with the Meter advance readings and MAR results of the metered Registrant.

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.1.14	Within 60WD of receipt of report	If discrepancy not resolved raise a formal dispute in accordance with BSCP11.	Registrant	Disputes Registrar	MAR report along with any supporting information.	Fax / Post / Email

SVG109/01 - Attachment H

Balancing and Settlement Code

BSC PROCEDURE

CVA Meter Operations for Metering Systems Registered in CMRS

BSCP06

Version 10.0

Date : 6 November 2008

BSCP06

relating to

CVA METER OPERATIONS FOR METERING SYSTEMS REGISTERED IN CMRS

1. Reference is made to the Balancing and Settlement Code and in particular, to the definition of "BSC Procedure" in Section X, Annex X-1 thereof.

2. This is BSC Procedure 06, Version 10.0 relating to CVA Meter Operations for Metering Systems Registered in CMRS.

3. This BSC Procedure is effective from 6 November 2008.

4. This BSC Procedure has been approved by the Panel.

AMENDMENT RECORD

VERSION	DATE	DESCRIPTION OF CHANGES	CRs INCLUDED	MODS PANEL REF
1.0	Code Effective Date	Designated Version	n/a	n/a
2.0	14/12/2000	Work outstanding at Go Active resolution of inconsistencies inclusion of consultation comments	NCR 221 & 220	09/006
3.0	10/12/2002	CDCA Improvement Project CP	CP780	n/a
4.0	24/06/2003	Change Proposal for CVA Programme June 03 Release	CP821	
5.0	24/06/2003	Approved Modification P62	P62	
6.0	30/06/2004	Change Proposals for CVA Programme June 04 Release	CP964, CP998	ISG/40/003
7.0	23/02/2005	CVA Programme Feb 05 Release	BETTA 6.3, CP1049, CP1054, CP1091	ISG/42/003 ISG/46/002
8.0	28/06/2006	June 06 Release	P190 CP1152	ISG/64/001
9.0	23/08/2007	P197 Release	P197	
10.0	06/11/2008	November 08 Release	CP1242	ISG88/01 SVG88/02 PAB88/03

CONTENTS

1. Introduction

1.1 Purpose and Scope of the Procedure

This procedure defines the obligations on the Meter Operator Agent (MOA) in relation to the work of Meter operations for Central Volume Allocation (CVA) Metering Systems registered in Central Meter Registration Service (CMRS). It also outlines the responsibilities of the MOA, Central Data Collection Agent (CDCA) and Registrant with regard to notification of work and of the sealing and re-sealing of CVA Metering Equipment for the following purposes:

(a) routine inspection testing, calibration and circuit isolations; and

(b) metering faults.

It additionally covers the reading of Meters before the start and on completion of the above work and the subsequent resealing of Metering Equipment. It also specifies the types of seals to be applied to Metering Equipment and the Metering Equipment to be sealed.

This BSCP should be read in conjunction with BSCP27, Technical Assurance of Half Hourly Metering Systems for Settlement Services, which describes key interfaces and timetabled responsibilities for the roles of the SVA and CVA Technical Assurance Agents (TAA), the processes for inspection and testing of Metering Equipment by the TAA and for rectifying non-compliances.

This procedure specifically excludes the following:

- Metering Equipment for Supplier Volume Allocation (SVA) which is covered by BSCP514; and
- Detailed requirements and intervals for carrying out inspection, testing and calibration of meters, which are covered in Code of Practice Four.

1.2 Main Users of the Procedure and their Responsibilities

This BSCP is to be used by the:

- MOA to understand its obligations in relation to CVA Meter operations;
- MOA to notify work which requires seals to be broken;
- MOA for the breaking of Metering Equipment seals and their resealing, and also for ensuring the necessary audit trail is maintained through the reading of Meters for reconciliation purposes;
- MOA for the sealing of new metering equipment.
- MOA for maintaining a local register of sealing pliers and a local register of seals applied; and
- BSCCo for maintaining a central register of MOA sealing IDs.

1.3 Balancing and Settlement Code Provision

This BSCP has been produced in accordance with the provisions of the Code. In the event of an inconsistency between the provisions of this BSCP and the Code, the provisions of the Code shall prevail.

1.4 Associated BSC Procedures

This procedure interfaces with the following BSCPs:

BSCP03	Data Estimation and Substitution for Central Volume Allocation
BSCP05	Meter Advance Reconciliation for Central Volume Allocation
BSCP20	Registration of Metering System for Central Volume Allocation
BSCP25	Registration of Transmission System Boundary Points, Grid Supply Points, GSP Groups and Distribution Systems Connection Points
BSCP27	Technical Assurance of Half Hourly Metering Systems for Settlement Purposes
BSCP38	Authorisations (or where appropriate BDTP38). Please note references throughout this document to BSCP38 also relate to the associated BDTP38 where appropriate
BSCP537	Qualification Process for SVA Parties, SVA Party Agents and CVA MOAs.

1.5 MOA Obligations

1.5.1 General Obligations

(a) Systems and Processes

The MOA shall use systems and processes so approved in accordance with BSCP537 in the operation of CVA Metering Equipment. These systems and processes must also comply with all other applicable requirements set out in the Code, this BSCP06 and its appendices and the BSC Procedures.

(b) Metering Equipment

The MOA shall ensure that the Import or Export of electrical energy by every CVA Metering System for which it is responsible is accurately recorded by Metering Equipment installed and maintained in compliance with the relevant Code of Practice (subject to any Metering Dispensations which may be in place).

(c) Communications

The MOA shall send and receive data and other information relating to its activities as MOA in accordance with BSCP02, BSCP03, BSCP05, this BSCP06, BSCP20 and, where appropriate, the Communication Requirements Document.

1.5.2 Registration Obligations

(a) Recording of Details

(i) The MOA shall record sufficient details, received from its associated Registrant, of its appointment in respect of a CVA Metering System to enable the MOA to perform its functions as MOA. These details shall include the relevant CVA Metering System Number, the associated Registrant's metering requirements and, where appropriate, the associated Distribution System Operator.

(ii) On appointment to a CVA Metering System and where existing Metering Equipment is to be used, the incoming MOA shall request the transfer of data and other information, in accordance with clause 1.5.2 b) iii), from the outgoing MOA to enable such incoming MOA to assume responsibility for the CVA Metering System.

(b) Termination of Appointment of MOA

(i) The MOA shall prepare and maintain plans that will enable its associated Registrant's obligations under the Code to continue to be met notwithstanding the expiry or termination of the MOA's appointment as the MOA. The plans, which the MOA undertakes to implement on any such expiry or termination, will include the immediate transfer of data and other information to an incoming MOA appointed by the associated Registrant or to the Panel.

(ii) On expiry or termination of the MOA's appointment as MOA in respect of a CVA Metering System, and where the existing Metering Equipment is to be used, the outgoing MOA shall transfer the data and other information, as specified in clause 1.5.2. b) iii) to the incoming MOA within 2 working days, when requested to do so by the incoming MOA.

(iii) Data and other information to be transferred shall include Meter Technical Details including those relating to the associated Communications Equipment as appropriate, commissioning data, mapping data and certification and/or calibration details.

1.5.3 Metering Obligations

(a) Energisation of Meters

(i) The MOA shall only energise a CVA Metering System if requested to do so by its associated Registrant.

(ii) The MOA shall as soon as reasonably practicable inform its associated Registrant and the CDCA of any change in the energisation status of any CVA Metering System to which it has been appointed.

(b) Installation, Removal and Re-programming of Meters

(i) The MOA shall maintain records and comply with systems and processes so approved in accordance with BSCP537 to commission, re-commission, remove, replace or reprogram Metering Equipment and shall inform its associated Registrant, the CDCA and, where applicable, the Distribution System Operator or the Transmission Company of the nature and date of any related work carried out within such time as shall allow the CDCA to carry out its obligations to ensure that correct data is taken into Initial Settlement Runs.

(ii) The MOA shall record proving, validation and communications errors found or reported by the CDCA as a result of a proving test and shall rectify any errors reported.

(c) Sealing Service

The MOA shall provide a sealing service and shall ensure that all Metering Equipment is sealed and re-sealed in accordance with this BSCP06.

1.5.4 Interface to Other Agents

(a) Information to the CDCA

(i) Upon any change of Meter Technical Details or upon the MOA's appointment in respect of a CVA Metering System, the MOA shall give Meter Technical Details, commissioning details and access details of the CVA Metering System and its energisation status to the CDCA.

(ii) The MOA shall inform the CDCA of the installation, repair, removal, reprogramming, energisation or de-energisation of any Metering Equipment for which the CDCA is responsible. The MOA shall use all reasonable endeavours to assist the CDCA in recovering data required for Settlement from any Metering Equipment that is about to be removed or de-energised.

(iii) Except in an emergency, the MOA shall give the CDCA sufficient notice of the installation, repair, removal, reprogramming, energisation or de-energisation of any Metering Equipment for which the CDCA is responsible to enable the CDCA to recover the data required for Settlement using its normal method of data collection.

(iv) When requested by the CDCA, the MOA shall provide opening/final meter readings to the CDCA following installation, removal, reprogramming, fault investigation, energisation, de-energisation or replacement of any Metering Equipment by the MOA in accordance with BSCP20 and this BSCP06.

(b) Meter Fault Reporting

(i) Upon the MOA being notified by any person or discovering that any Metering Equipment for which the MOA is responsible is potentially recording incorrect data, the MOA shall investigate and rectify the problem and notify its associated Registrant and the CDCA of the

nature of the fault, the date and time at which it was rectified and the initial reading of the cumulative total registers following rectification.

(ii) The MOA shall report Metering Equipment faults to its associated Registrant and the CDCA and advise the CDCA as to the period covered by the fault. For Metering Equipment faults located at Offshore Power Park Modules, that are subject to access difficulties for more than 5WD due to health and safety reasons, the MOA shall notify BSCCo using Form BSCP06/4.9 'Risk Assessment of Metering Equipment Fault at Offshore Power Park Module'.

(iii) The MOA shall separately identify Metering Equipment faults affecting data quality and those not affecting data quality and shall record the date on which each fault was reported and the date on which each fault was cleared. For this purpose a fault affecting data quality shall be treated as cleared when the relevant Metering System once again records in compliance with the relevant Code of Practice.

1.5.5 Service Levels

The MOA shall perform the services to be performed by it as MOA pursuant to this BSCP06 to standards which shall be at least as good as those specified in Appendix 4.8.

1.5.6 Input, Processing and Output

Controls to ensure that input, processing and output are valid may include the use of software validation checks and exception reporting to identify problems.

1.6 Operational Emergencies

Seals may be broken by others under instruction from operational staff in an operational emergency or for safety reasons in an emergency, providing the MOA is informed at the earliest opportunity, stating the reasons for so doing. The MOA can then arrange to reinstate any seals affected. This includes equipment which is declared a "point of isolation" e.g. secondary fuses associated with metering VTs.

1.7 Routine Work and Metering Faults

All routine work and Metering System faults should be dealt with under Section 3.1 of this procedure.

Routine work shall be regarded as any work planned in advance which:

- Is not associated with the CVA Metering Equipment but requires secondary metering VT isolation. This type of work is usually circuit planned outages.

- Associated with the CVA Metering Equipment which is not due to a fault. This type of work is usually replacement of Outstation battery, calibration of Meters, accuracy tests of Meters.

1.8 Register of Sealing Pliers

For the purpose of maintaning an audit trail of the Metering Equipment seals applied, CVA MOAs shall maintain a register of sealing pliers detailing when, to whom and which unique pair(s) of sealing pliers have been issued for use. The register should additionally specify details of any lost or stolen pliers, any pliers sent for repair (CVA MOAs shall ensure that records relating to repairs are kept for at least 10 years) and the dates on which any pliers were destroyed.

CVA MOAs shall ensure their register of sealing pliers is made available for inspection by the BSC Auditor and the TAA for audit purposes.

1.9 Register of Seals Applied

CVA MOAs shall maintain a register containing details of when seals were applied to Metering Equipment for individual circuits. The details shall include:

- Circuit name;
- Metering Equipment sealed;
- Date seals applied;
- Sealing pliers number; and
- Signature of person applying seals.

A template for the register of seals applied is provided in Appendix 4.3 of this BSCP, which may be used by CVA MOAs.

Copies of this register shall be kept on site to enable the CDCA to carry out the visual inspection of Metering Equipment checks required in section 4.3 of BSCP05 'Meter Advance Reconciliation for Central Volume Allocation' when it carries out Meter Advance Reconciliations (MARs) in accordance with BSCP05.

In addition, this register of seals applied shall be made available for inspection by the BSC Auditor (off site) and the TAA (on site) for audit purposes.

1.10 Central Register of CVA MOA Sealing IDs

BSCCo shall maintain a central register of CVA MOA sealing IDs and issue a unique ID to each Qualified CVA MOA on request. The CVA MOA sealing ID will be associated with the CVA MOA's Party Agent ID registered in Central Systems. The CVA MOA sealing ID may only be used by the CVA MOA it was allocated to and therefore cannot be transferred to any existing or new CVA MOAs. Where a CVA MOA ceases to operate in the CVA market, it will be required to destroy the sealing pliers associated with its CVA MOA sealing ID.

A CVA MOA can use an SVA MOA sealing ID in the CVA market where the CVA and SVA MOAs are from the same company. However, where the SVA MOA has more than one sealing ID, only one must be declared by the CVA MOA in order that the BSCCo can ensure that MOA sealing IDs remain unique in the CVA market.

Where the same MOA sealing ID is used in both markets, and the MOA subsequently ceases to operate in the CVA market only, the sealing pliers associated with CVA MOA sealing ID need not be destroyed as the TAA will have an effective from and effective to date for the relevant CVA Party Agent ID and therefore the MOA sealing ID. However, where an MOA subsequently ceases to operate in both SVA and CVA markets, the sealing pliers associated with the CVA MOA sealing ID must be destroyed in line with the SVA requirements.

The BSCCo will ensure that the up-to-date register of all CVA MOA sealing IDs, along with their effective from and effective to dates, are made available to the BSC Auditor and the TAA for audit purposes.

2. Acronyms and Definitions

2.1 List of Acronyms

The following is a list of acronyms used in BSCP06:

BDTP	BETTA Data Take On Procedure
BSCCo	Balancing and Settlement Code Company
CDCA	Central Data Collection Agent
CMRS	Central Meter Registration Service
CVA	Central Volume Allocation
LDSO	Licensed Distribution System Operator
MOA	Meter Operator Agent
MSID	Metering System Identifier
MSSY	Metering Sub System Identifier
SVA	Supplier Volume Allocation
TAA	Technical Assurance Agent
TC	Transmission Company
UTC	Co-ordinated Universal Time
WD	Working Day

2.2 List of Definitions

Full definitions of the above acronyms in Section 2.1 are included in the Code.

3. Interface and Timetable Information

3.1 Routine Work and Metering Faults

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.1.1	For routine work, prior to the day work is to be carried out, or, for work carried out in respect of a metering fault	If MOA wishes to carry out some work give notification of date, time and place where work required, or, Proceed to step 3.1.3	MOA[1]	Registrant	Details of the work to be completed, including date, time and place.	Letter / Fax / Email
3.1.2	Following 3.1.1, and prior to the day work is to be carried out.	If Registrant wishes to attend the site, he provides confirmation.	Registrant	MOA	Confirmation of attendance	Letter / Fax / Email

[1] Where the Registrant and MOA are the same, the Registrant can initiate the process but only in the role of MOA.

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.1.3	Day work carried out	Give notification of work to be carried out and where appropriate request CDCA to remotely interrogate Outstation(s).[2] Where appropriate, take "before" Meter readings. Break seal(s).	MOA MOA MOA	CDCA	 BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet This form must be signed by an authorised person as registered under BSCP38.	Phone / Fax / Email Internal Internal
3.1.4	On the day when work has been completed	Where appropriate, take "after" Meter readings, reseal Metering Equipment. Update register of seals applied and ensure the details are available for inspection on and off site. Where appropriate, request CDCA to remotely interrogate Outstation(s).	MOA MOA	 CDCA	BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet Register of seals applied Request to remotely interrogate Outstation(s)	Internal Phone / Fax / Email
3.1.5	Within 3WD of 3.1.4	Send confirmation and details of work carried out, along with "before" and "after" readings.	MOA	CDCA, Registrant	BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet	Letter / Fax / Email

[2] In the case of metering faults , located at Offshore Power Park Modules where access has been prevented for health and safety reasons for more than 5 WD of 3.1.3, the MOA shall notify BSCCo using Form BSCP06/4.9 'Risk Assessment of Metering Equipment Fault at Offshore Power Park Module'. BSCCo shall monitor progress and if necessary inform the relevant Panel Committee of any unsatisfactorily controlled risk.

3.2 New Metering Equipment Sealing

This section is utilised for new registration of Metering System in accordance with BSCP20 where the initial Meter readings and sealing of Metering Equipment is required before the Metering System effective date.

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.2.1	Prior to the Effective From Date of the Metering System	Take "initial" Meter readings, seal all Metering Equipment and update register of seals applied.	MOA		BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet Signing witness must be an authorised person as registered under BSCP38.	Internal
3.2.2	Within 3WD of 3.2.1	Provide initial Meter readings.	MOA	CDCA, Registrant	BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet	Letter / Fax / Email

3.3 Removing Seals From De-Registered Metering Equipment

This section is utilised for newly de-registered Metering System in accordance with BSCP20 where the final Meter readings and removal of seals is required after the Metering System effective date.

REF	WHEN	ACTION	FROM	TO	INPUT INFORMATION REQUIRED	MEDIUM
3.3.1	On date agreed under BSCP20				BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet Signing witness must be an authorised person as registered under BSCP38	Internal
3.3.2	Within 3 WD of 3.3.1	Provide final Meter readings.	MOA	CDCA, Registrant	BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet	Letter / Fax / Email
3.3.3	Following 3.3.2	Perform Meter Advance Reconciliation in accordance with BSCP05.	CDCA			Internal

3.4 Fault Investigation and Resolution

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.4.1	As soon as aware of inconsistency or possible fault.	Send notification of inconsistencies or possible fault and request investigation.	CDCA[3] or BSCCo or any Party	Registrant BSCCo MOA LDSO or TC as appropriate	BSCP06/4.5 Part A 'Metering Equipment Fault Report'.	Fax / Letter / Email
3.4.2	As soon as possible after 3.4.1	Investigate problem: a) Resolve the issue; or b) Send request to MOA to inspect and test suspect metering.	Registrant	a) Internal; b) MOA	Details of inconsistency.	Fax / Letter / Email
3.4.3	Within 3 WD of receipt of request in 3.4.2	Investigate suspect metering and send report of findings.	MOA	CDCA Registrant	BSCP06/4.5 Part B 'Metering Equipment Fault Report'	Fax / Letter / Email
3.4.4	As soon as possible after receipt of data in 3.4.3	Report resolution of problem.	Registrant	BSCCo LDSO or TC as appropriate	Details of findings and resolution of problem	Fax / Letter / Email
3.4.5	As soon as possible after receipt of data in 3.4.3	Where an investigation indicates that a fault has caused incorrect Metered Data to be recorded, estimate Metered Data in accordance with BSCP03.	CDCA	Registrant LDSO or TC as appropriate	Details of estimated Metered Data.	Fax / Letter / Electronic

[3] In addition to informing the Registrant, BSCCo and LDSO or TC, as appropriate, the CDCA shall also inform the MOA

4. Appendices

4.1 This form is no longer used

4.2 This form is no longer used

4.3 Register of Seals Applied

This form is no longer used. However, it may be used by CVA MOAs as a template for a register of seals applied.

4.4 This form is no longer used

4.5 Metering Equipment Fault Report

This form is to be used by the CDCA, BSCCo or any other Party to report inconsistencies or possible faults with Metering Equipment, or the MOA to report the action taken to rectify a fault.

4.6 Notification of Completed Work/Meter Reading Sheet

This form is to be used by the MOA (signed by an authorised person as registered under BSCP38 Authorisations) to give details of any work carried out on Metering Equipment, and to provide "before" and "after" Meter readings. It is also used to provide "initial" Meter readings for new Metering Equipment, and "final" Meter readings for de-registered Metering Equipment.

4.7 Equipment to be Sealed, Types of Seals and Responsibilities for Sealing

This appendix specifies the Metering Equipment to be sealed, the types of seals to be applied to the Metering Equipment and where the responsibilities for sealing lie.

4.8 Meter Operator Agent Service Levels

This appendix has effect for the purposes of Section 1.5.5 of this BSCP06 to determine;

(i) the functions to be performed by the Meter Operator Agent, as described in columns 2 to 5 of the table set out in this Appendix, in respect of which minimum standards of performance are required;

(ii) the minimum standards of performance (Service Levels) relating to the functions referred to in paragraph (i) above, as described in columns 6 and 7 of the table set out in this Appendix; and

(iii) a reference number (Serial) in respect of each Service Level, as described in column 1 of the table set out in this Appendix.

4.1 BSCP06/4.1 This form is no longer used

4.2 BSCP06/4.2 This form is no longer used

4.3 BSCP06/4.3 Register of Seals Applied

This form is no longer used but may be used as a template by CVA MOAs.

Site: .....

MOA: ..... *Registrant:* .....

Circuit Name	Metering Equipment Sealed (e.g. Meter, Data Collector, Meter Panel Door, Meter Cabinet Rear Door, Potential Fuses, Test Terminal Block, etc)	Date Seals Applied	Sealing Pliers Number	Signature of Person Applying Seals

4.4 BSCP06/4.4 This form is no longer used

4.5 BSCP06/4.5 Metering Equipment Fault Report

Part A (CDCA-I038) **From:** CDCA or BSCCo or any Party **To:** Registrant, BSCCo, MOA LDSO or TC (as appropriate)

Registrant: _____

MOA: _____

MSID(s): _____

Date: _____

CDCA Fault Ref: _____

Communications	☐
Outstation Id:	
Comms Address:	
Device Type:	
Last Successful Call:	
Comms Test:	
Comments:	

Data Quality	☐
Type:	
Outstation Id(s):	
Subsystem Id:	
Channel(s) Affected:	
Comments:	

Time Tolerance	☐
Outstation Id:	
Time Difference (secs):	
Fast/Slow:	
Comments:	

Meter Advance Reconciliation	☐
Meter Serial No:	
Outstation Id:	
Outstation Channel:	
Other Details:	
Comments:	

Other	☐
Comments:	

Part B (CDCA-I015) **From:** MOA **To:** Registrant, CDCA

Date:

MOA Fault Ref:

CDCA Fault Ref:

MSID(s)

Action Taken:
Other Comments:

4.6 BSCP06/4.6 Notification of Completed Work/Meter Reading Sheet

PAGE 1 OF __

To: _____ **Date Sent:** _____

From: Participant Details

MOA ID: _____ Name of Sender: _____

Contact email address: _____

Our Ref: _____ Contact Tel. No. _____

Name of Authorised Signatory: _____

Authorised Signature: _____ Password: _____

PLEASE COMPLETE IN BLOCK CAPITALS

Site Name: .....

Registrant: .....

MSID: ..... *Name of Meter Reader:* ..... .

Circuit Name: .....

Start date/time (UTC): …… *End date/ time (UTC):* ……

Work Carried Out: ……
……
……
……

Before Reading	Physical Meter	Outstation (Primary)_	Outstation (Secondary)
Serial No.:			
Import MWh	.	.	.
Export MWh	.	.	.
Import MVarh	.	.	.
Export MVarh	.	.	.

After Reading	Physical Meter	Outstation (Primary)_	Outstation (Secondary)
Serial No.:			
Import MWh	.	.	.
Export MWh	.	.	.
Import MVarh	.	.	.
Export MVarh	.	.	.

BSCP06/4.6Notification of Completed Work/Meter Reading Sheet continued

PAGE __ OF __

MSID*:* .....

Circuit Name: .....

Start date/time (UTC): …… *End date/ time (UTC):* ……

Work Carried Out: ……
……
……
……

Before Reading	Physical Meter	Outstation (Primary)_	Outstation (Secondary)
Serial No.:			
Import MWh	.	.	.
Export MWh	.	.	.
Import MVarh	.	.	.
Export MVarh	.	.	.

After Reading	Physical Meter	Outstation (Primary)_	Outstation (Secondary)
Serial No.:			
Import MWh	.	.	.
Export MWh	.	.	.
Import MVarh	.	.	.
Export MVarh	.	.	.

Circuit Name: .....

Start date/time (UTC): …… *End date/ time (UTC):* ……

Work Carried Out: ……
……
……
……

Before Reading	Physical Meter	Outstation (Primary)_	Outstation (Secondary)
Serial No.:			
Import MWh	.	.	.
Export MWh	.	.	.
Import MVarh	.	.	.
Export MVarh	.	.	.

After Reading	Physical Meter	Outstation (Primary)_	Outstation (Secondary)
Serial No.:			
Import MWh	.	.	.
Export MWh	.	.	.
Import MVarh	.	.	.
Export MVarh	.	.	.

4.7 Equipment to be Sealed, Types of Seals and Responsibilities for Sealing

This Appendix specifies the minimum requirements for:

- The equipment to be sealed;
- The types of seal to be used and their purpose;
- General sealing practice; and
- Particular procedures for the control of specified seals and dies.

4.7.1 Equipment to be Sealed

The table below shows equipment to be sealed, the type of seal to be applied and by whom seals may be removed and/or applied.

Measurement Technique	***Metering Equipment to be sealed***	***MOA***	***LDSO/ Transmission Co/ Generation Co***
CT operated Low voltage	Primary voltage fuse only if no secondary fuse	S	
	CT chamber	I	P
	Meter terminal cover	S	
	Meter case (cover)	S	
	CT terminal cover	S	
	Test terminal block	S	
	Switch (controlling supply)	I	P
	Secondary voltage fuse	S	
	Communications port	S	
	Metering Equipment connections to Load control equipment	S	
	Bus bar chamber	I	P
CT/VT operated High voltage (additional to LV)	VT racking	I	P
	VT fuses (on switchgear)	I	P

Measurement Technique	*Metering Equipment to be sealed*	*MOA*	*LDSO/ Transmission Co/ Generation Co*
	VT Marshalling box	I	P
	VT fuse (on panel)	S	
	Auxiliary fuses	S	
	CT Marshalling box	I	P

Key: S - Security seal I -Indicative seal P - Padlock

4.7.2 Types of Seal and Purpose

Table 1 identifies three generic types of 'seal' by purpose:

- A security seal shall be used where both protection to avoid danger (to make opening of the equipment difficult) and indication of any interference are required. Where applied to Metering Equipment by a CVA MOA it shall be a specified seal as defined under 'Specified Seal, Wire Rope and Associated Sealing Equipment' below;

- An indicative seal or label shall be used where only an indicative warning is required that work on the equipment could compromise the operation of Metering Equipment; and

- A padlock shall be used to protect and to avoid danger on certain types of distribution/transmission equipment (to make opening of the equipment very difficult except to authorised persons having keys for the purposes of carrying out operations under required Safety Rules).

Specified Seal, Wire Rope and Associated Sealing Equipment

A specified seal is a particular form of security seal. The requirements of a specified seal are that it shall:

- be a tin-plated, annealed, copper ferrule;

- not be less than 5.0mm nor more than 7.0mm long;

- have an internal diameter which is not less than 1.98mm nor more than 2.28mm;

- be of some constant cross-section of such a size and shape so that its external perimeter lies within a circle whose diameter is not less than 4.06mm nor more than 4.6mm and the wall is nowhere less than 0.72mm thick; and

- be crimped and marked on one side with the identification symbol appropriate to

the MOA and on the other side with the 3-digit identification number of the Meter Operative. Alternatively, the specified seal can be crimped with up to 3 digits on each side to identify the Meter Operative and the identification symbol appropriate to the MOA, or the MOA's company name, may be impressed on a seal's flange or protuberance, provided that the design of the flange or protuberance is one approved by the BSCCo, from time to time.

The Requirements of Wire Rope are that it shall:

- be manufactured from 7 strands of drawn, class Z, zinc-coated wire complying with BS 2763:1982;
- have a diameter of not less than 0.914mm; and
- have a breaking load of not less than 880N.

The requirements for sealing equipment are that it shall crimp specified seals onto wire rope sufficiently to withstand a tensile load of not less than 200N, in order to secure equipment so as to prevent accidental breaking or removal of the seal or wire rope.

Indicative Seal

The type used may be at the discretion of the party concerned. The main purpose, particularly on CT/VT equipment, is to warn persons intending to work on such equipment that their actions might interfere with metering integrity.

Padlock

General practice is to use brass bodied, hardened steel hasp locks with a common key suite so that any person with appropriate authority, issued with a master key, can open them. In some cases a coloured sheath (e.g. red) may be applied to indicate danger.

4.7.3 Guidance on Sealing Practice

General

Metering Equipment and related distribution/transmission equipment shall be sealed following initial energisation and shall be resealed following any subsequent works that require the removal of seals. The party carrying out such works shall be responsible for resealing equipment and for taking the removed seals from the site and destroying them, whether they are owned by that party or are the property of another party.

General Guidance Specific to Meter Operator Agents

Each Meter Operator Agent shall have a system for sealing and resealing, which shall include using a seal uniquely identifiable to it as specified in 'Specified Seal, Wire Rope and Associated Sealing Equipment' above.

4.7.4 Control of Specified Seals and Associated Dies

Sealing Pliers and Dies

Sealing pliers, to be used with uniquely identified dies for crimping and marking specified seals, must be provided by MOAs for each Meter Operative. Dies shall not be transferred between MOAs. In addition:

- No MOA shall retain any duplicate sets of dies.
- Sealing pliers, dies or specified seals shall not be used other than for sealing Metering Equipment.
- Sealing pliers with dies that do not make legible marks shall not be used.

Destruction of Dies

A MOA shall be required to destroy sets of dies that have been damaged or are no longer required because the relevant Meter Operative will no longer be sealing Metering Equipment on its behalf.

In the event of a MOA ceasing to operate all sets of sealing pliers and dies shall be destroyed by it forthwith.

4.8 Meter Operator Agent Service Levels

For the purposes of this Appendix:

(a) the references in column 3 of the table below to a numbered paragraph are to the relevant paragraph in Section 1.5 of this BSCP06;

(b) the references in column 4 of the table below to a sub-process/data flow are to the relevant sub-process or data flow as described in the relevant BSC Procedure or Appendix 4.8 to this BSCP06;

(c) references to a Distribution System Operator are to the Distribution System Operator of the Distribution System in whose area the relevant CVA Metering Systems are located (if applicable);

(d) references to "Timescales" are to those specified by BSCP02, BSCP20 and, if applicable, the Settlement Calendar;

(e) references to a certain percentage of tasks being completed within a certain specified period are to be read as a reference to that percentage of tasks being completed during an applicable reporting period as specified by BSCP20;

(f) references to an item being "valid" are to an item which conforms to an applicable Data Catalogue item;

(g) reference to an item being in "correct format" are to an item which complies with the applicable Data Catalogue format or the format specified by BSCP02, BSCP20 and this BSCP06;

(h) references to an item being "accurate" are to an item being correctly recorded; and

(i) in calculating percentages, the performance figures shall be rounded up or down to the nearest two decimal places (with 0.005 being rounded upwards).

4.8.1 Meter Operator Service Levels – BSCP06

Serial	Sender	Process	Sub-process / Data Flow	Recipient	Performance Measure	Service Levels	Reporting Method
1	Meter Operator Agent	1.5.4 Interface to other Agents	Fault repairs	Meter Operator Agent	Time to rectify faults which would constitute a category 1 or category 2 non compliance as defined in BSCP27	(i) 95% rectified within 5 working days of receipt of notification; (ii) 99% rectified within 15 working days of notification.	Provision of data under 10.1.1 of PSL100
2	Meter Operator Agent	1.5.2 Registration Obligations	Meter Technical Details	Incoming Meter Operator Agent	Complete, valid, correct format and accurate within Timescales	(i) 95% within 5 working days in accordance with this BSCP; (ii) 99% within 10 working days in accordance with this BSCP06.	Provision of data under 10.1.1 of PSL100
3	Meter Operator Agent	1.5.4 Interface to other Agents	Meter Technical Details	CDCA	Complete, valid, correct format and accurate within Timescales	(i) 95% within 5 working days in accordance with BSCP02 (ii) 99% within 15 working days in accordance with BSCP02.	Provision of data under 10.1.1 of PSL100
4	Meter Operator Agent	1.5.4 Interface to other Agents	Fault Resolution Reports	Registrant CDCA	Complete, valid, correct format and accurate within Timescales	(i) 95% within 5 working days in accordance with this BSCP06; (ii) 99% within 15 working days in accordance with this BSCP06.	Provision of data under 10.1.1 of PSL100

BSCP06/4.9 Risk Assessment of Metering Equipment Fault at Offshore Power Park Module

To: BSCCo **Date Sent:**
From: Participant Details MOA ID: Name of Sender:
Our Ref: Contact Tel. No.:
Name of Authorised Signatory: Authorised Signature: Password:

Metering Equipment Details

Site: **MSID:**

Circuit(s):

Details of Metering Fault

Details of Proposed Rectification and reason for Delay

Proposed Date of Rectification:

BSCP06/4.9 (Continued) Page 2 of 2

Metering System Component	Impact on Data Quality	Method of Controlling Risk
Primary Plant		
CTs and VTs		
Cabling and Marshalling Boxes		
Metering Panel		
Meters		
Outstations		
Auxiliary Power Supplies		
Communications Equipment		
Other		

Existing Control Measures

Additional Information

SVG109/01 - Attachment I

Balancing and Settlement Code

BSC PROCEDURE

Technical Assurance of Half Hourly Metering Systems for Settlement Purposes

BSCP27

Version 10.0

Date: 25 June 2009

BSC PROCEDURE 27

relating to

Technical Assurance of Half Hourly Metering Systems for Settlement Purposes

1. Reference is made to the Balancing and Settlement Code dated Code Effective Date and, in particular, to the definition of "BSC Procedure" in Section X, Annex X-1 thereof.

2. This is BSC Procedure 27 Version 10.0 relating to Technical Assurance of Half Hourly Metering Systems for Settlement Purposes.

3. This BSC Procedure is effective from 25 June 2009.

4. This BSC Procedure has been approved by the BSC Panel.

AMENDMENT RECORD

Version	Date	Changes	CPs Included	Mods Panel Ref
1.0	01/06/04	New BSCP (This BSCP supersedes BSCP526 and BSCP26)	CP998	
2.0	BETTA Effective Date	BETTA 6.3 and SVA February 2005 Release	CP1091 and BETTA 6.3	SVG/48/004
3.0	02/11/05	CVA Nov 05 Release	CP1062 version 1	SVG/56/014
4.0	22/02/07	Reformatted and Changes for CP1176 Updated following industry review	CP1164 CP1172 CP1176	SVG/68/04 ISG/69/01 ISG/66/06 SVG/66/04 ISG/68/002 SVG/67/002
5.0	23/08/07	P197 Release	P197	
6.0	01/11/07	November 07 Release	CP1195 CP1210	ISG77/03 SVG77/04 ISG79/02 SVG79/02
7.0	28/02/08	February 08 Release	CP1212	ISG81/01 SVG81/01
8.0	26/06/08	June 08 Release	CP1223	SVG84/02, ISG84/01, TDC109/01, PAB84/11
9.0	26/11/08	P207 Release	P207	ISG91/01 SVG91/06
10.0	25/06/09	June 09 Release	CP1265	ISG97/01 SVG97/01

CONTENTS

1 Introduction

1.1 Purpose and Scope of the Procedure

This BSC Procedure (BSCP) defines the process of inspections of Supplier Volume Allocation (SVA) Half Hourly Metering Systems registered in a Supplier Meter Registration System (SMRS) and Central Volume Allocation (CVA) Metering Systems registered in the Central Meter Registration Service (CMRS).

It describes the key interfaces and timetable responsibilities for the role of the Technical Assurance Agent (TAA) and interested parties in the inspection of Metering Systems. The primary aim of Technical Assurance is to monitor Registrants' and Party Agents' compliance with their obligations as defined in the Balancing and Settlement Code (the Code) and Code Subsidiary Documents (CSDs) to ensure that the Active Energy Imported and/or Active Energy Exported through Boundary Points and System Connection Points is complete and accurate.

1.2 Risk Based Performance Assurance Framework

Performance Assurance Techniques (PAT) will be applied to Performance Assurance Parties (PAP) based on the net significance of the applicable Settlement Risk and an assessment of the PAP's contribution to the Settlement Risk.

Settlement Risks and their net significance are captured on the Risk Evaluation Register (RER). All the Settlement Risks identified are rated in terms of severity of impact and probability (including a weighting for the strength of controls).

The Settlement Risks are assigned PATs to mitigate those risks and these PATs are recorded in the Risk Operating Plan (ROP) against each Settlement Risk.

The RER and the ROP are produced for a Performance Assurance Operating Period in accordance with the Annual Performance Assurance Timetable and the agreed Risk Evaluation Methodology (REM), which details the processes used to identify and evaluate the Settlement Risks and assess their materiality.

A Risk Management Plan (RMP) is created for each PAP based on the RER and the ROP and in accordance with the REM. The RMP will detail the PATs that will be deployed to a PAP during the course of a Performance Assurance Operating Period based on the Settlement Risks that are applicable to that PAP and the extent that the Settlement Risk applies to the PAP. If a PAP disagrees with their RMP, then there are provisions within the Code for them to query or appeal against it.

At the end of a Performance Assurance Operating Period, the Performance Assurance Board (PAB) will prepare an Annual Performance Assurance Report for the Panel detailing the assurance that has been provided during the course of the period, the extent to which Settlement Risks have been mitigated, and BSCCo costs of providing that assurance.

Technical Assurance is a Performance Assurance Technique and will be deployed to a PAP in relation to relevant Settlement Risks in accordance with the agreed RMP.

1.3 Main Users of the Procedure and their Responsibilities

This Procedure should be used by the following for each type of Metering System:

CVA Metering Systems	SVA Metering Systems
▪ BSCCo ▪ Central Data Collection Agent (CDCA) ▪ Market Participants ▪ Meter Operator Agents (MOA) ▪ Panel ▪ Panel Committees ▪ Performance Assurance Administrator (PAA) ▪ Registrants ▪ Technical Assurance Agent (TAA)	▪ BSCCo ▪ Half Hourly Data Collectors (HHDCs) ▪ Licensed Distribution System Operators (LDSOs) ▪ Market Participants ▪ Meter Operator Agents (MOAs) ▪ Panel ▪ Panel Committees ▪ Performance Assurance Administrator (PAA) ▪ Registrants ▪ Supplier Meter Registration Agents (SMRAs) ▪ Technical Assurance Agent (TAA)

1.4 Use of the Procedure

The Registrant is responsible for ensuring the compliance of its Party Agents, in particular the MOA and DC, with the Code and CSDs.

The TAA shall determine a Metering System to be non-compliant if the Code or CSDs are not being adhered to, subject to any Metering Dispensations applicable to the Metering Equipment.

Throughout this procedure, where a timescale is stated, it refers to the number of Working Days (WD) by which the activity described shall be completed.

1.5 Key Milestones

The key milestones in this procedure are:

- Extracts from CDCA and SMRA for the sampling of Metering Systems as detailed in section 1.10.
- $20WD^2$ notice to the Registrant and MOA of a TAA Inspection-Visit.

1.6 Balancing and Settlement Code Provision

This BSCP has been produced in accordance with the provisions of the Code and in particular Section L. In the event of an inconsistency between the provisions of this BSCP and the Code, the provisions of the Code shall prevail.

1.7 Associated BSC Procedures

This BSCP interfaces with:

CVA Metering Systems	SVA Metering Systems
▪ BSCP02 – Proving Test Requirements for CVA Metering Systems ▪ BSCP06 – CVA Meter Operations for Metering Systems Registered in CMRS ▪ BSCP11 – Trading Queries and Trading Disputes ▪ BSCP20 – Registration of Metering Systems for Central Volume Allocation ▪ BSCP32 – Metering Dispensations ▪ BSCP537 – Qualification Process for SVA Parties, SVA Party Agents and CVA MOAs ▪ BSCP538 – Error and Failure Resolution ▪ BSCP601 - Metering Protocol Approval and Compliance Testing	▪ BSCP11 – Trading Queries and Trading Disputes ▪ BSCP32 - Metering Dispensations ▪ BSCP501 - Supplier Meter Registration Service ▪ BSCP502 – Half Hourly Data Collection for SVA Metering Systems Registered in SMRS ▪ BSCP514 –SVA Meter operations for Metering Systems registered in SMRS ▪ BSCP515 – Licensed Distribution ▪ BSCP535 – Technical Assurance ▪ BSCP537 – Qualification Process for SVA Parties, SVA Party Agents and CVA MOAs ▪ BSCP538 – Error and Failure Resolution ▪ BSCP550 - Shared SVA Meter Arrangement of Half Hourly Import and Export Active Energy ▪ BSCP601 - Metering Protocol Approval and Compliance Testing

1.8 Responsibilities

For the purpose of this BSCP the Registrant is the Party responsible for the provision of Code-compliant Settlement Metering Systems.

1.9 Metering System Sampling Groups

For SVA, the total number of Metering Systems to be inspected in any one year shall be as determined by the Performance Assurance Board (PAB) in accordance

with the ROP. This may include a percentage of re-inspections. The selection of the actual Metering Systems to be inspected shall be at the discretion of BSCCo.

The TAA shall select SVA Metering Systems for the following sampling groups:

- Targeted Inspections
- Specific Sample
- Main Sample

For CVA, the total number of Metering Systems to be inspected in any one year shall be as directed from time to time by the PAB. This will include a percentage of re-inspections. The selection of the Metering Systems to be inspected shall be at the discretion of BSCCo, in accordance with the scope as directed by the PAB.

The TAA shall select CVA Metering Systems for the following sampling groups:

- Targeted Inspections
- Main Sample

1.9.1 Targeted Inspections

The TAA may target a number of Metering Systems where non-compliance is suspected. These may be identified as a consequence of information obtained by BSCCo (including that information provided by the PAA), by the TAA or as directed by the PAB. BSCCo will inform the TAA of those Metering Systems that require a targeted Inspection Visit.

The basis for this sample will be on information provided by Registrants and other parties to enable BSCCo to target specific Metering Systems, GSP Groups, types of Metering Equipment, Party Agents or BSC Parties. Targeted inspections will not necessarily be carried out each time a group of inspections is arranged.

1.9.2 Specific Sample - SVA Only

It is intended that specific samples will focus on where the risk to Settlement is perceived to be greatest. The PAB will determine the size of the specific sample. It is anticipated this specific sample will account for no more than 20% of the total number of visits agreed by the PAB to be performed each year. The focus of this specific sample will be set by the PAB on an annual basis. It is envisaged that this group will be sampled from, but not limited to, the following:

1. Code of Practice (CoP) One, Two and G Metering Systems and Scottish Code of Practice One (S1) and Two (S2) Metering Systems
2. Import/Export Metering Systems: those Metering Systems that record Import and Export electricity will be targeted for inspection, to ensure that the technical details have been correctly recorded in Settlement.
3. Multi-Feeder Metering Systems.

4. Complex Sites: those Metering Systems that cannot be adequately expressed via the D0268, Half Hourly Meter Technical Details, and where the MOA is required to provide additional information.

The registered MOA and LDSO will be responsible for and will use reasonable endeavours to provide complete and accurate Metering System data, upon request to the TAA or BSCCo for the purposes of Technical Assurance.

1.9.3 Main Sample – CVA and SVA

The TAA, on behalf of BSCCo, shall ensure that a representative sample of Metering Systems is inspected for both SVA and CVA Half Hourly Metering Systems. The selection of Metering Systems will be based upon consideration of:

- GSP Group (SVA Only)
- Registrant
- Meter Operator Agent
- Code of Practice
- Metering Equipment
- Previous inspection(s)

1.10 Information Required to Enable Sampling of Metering Systems

1.10.1 Specific Sample – SVA

In order to ensure that the relevant Metering Systems are inspected, each Registrant, LDSO or MOA where appropriate will provide details of all Metering Systems(described in section 1.9.2) so that a representative sample can be determined by the TAA. The Registrant will provide the following information for each Metering System:

- Metering System ID.
- GSP Group.
- MOA ID.
- HHDC ID.
- Site Address Details.
- Applicable CoP.
- Details of any current applicable Metering Dispensation

The TAA will, on behalf of BSCCo, create a schedule of inspections that meets the PAB's agreed requirements.

1.10.2 Main Sample – CVA

The CDCA shall submit an electronic list of all Metering System IDs registered in the Central Meter Registration Service (CMRS), together with associated information to BSCCo. The lists shall be provided four times a year on dates agreed with BSCCo. The required information will be forwarded to the TAA to initiate the sample selection process.

The TAA will use reasonable endeavours to minimise the number of repeated inspections when selecting the Metering Systems to be inspected.

The TAA will select 10% more Metering System IDs than will be inspected. The additional 10% will enable the TAA to categorise the Metering Systems and ensure that there is no bias towards any one Party, Metering Equipment type or sampling area. This initial sample will be sub-divided by Registrant and MOA.

BSCCo will provide additional guidance for the selection of sampled inspections.

On identification of the Metering System IDs the CDCA will be required to provide the following additional information in order to finalise the sample:

- Meter Technical Details for each Metering System ID (as detailed in BSCP20).

The relevant Registrant will then be notified of the Metering Systems to be inspected.

1.10.3 Main Sample – SVA

This is the main sample selection process (excluding those detailed in 1.9.2) for SVA Metering Systems.

Each SMRA shall ensure that the details it holds are updated daily to a central online database in line with the requirements detailed in the Master Registration Agreement (MRA), together with any associated information as specified in BSCP501 to the PAA via BSCCo. The required information will then be used by the TAA to initiate the sample selection process.

The TAA will use reasonable endeavours to minimise the number of repeated visits when selecting the Metering Systems to be inspected.

The TAA will select 10% more Metering System IDs than will be inspected. The additional 10% will enable the TAA to categorise the Metering Systems ensuring that there is no bias towards any one Party, Metering Equipment type or sampling area. This initial sample will be sub divided by GSP Group, Registrant and MOA.

Once the Metering System IDs have been identified the Registrant will be required to provide the following additional information in order to finalise the sample:

- Meter Technical Details for each Metering System ID (as detailed in the D0268, Half Hourly Meter Technical Details).

The relevant Registrant will then be notified of the Metering Systems to be inspected.

1.11 Re-Inspections

Where a category 1 or category 2 non-compliance has been identified and subsequently reported as rectified, it is possible that the Metering System will be re-inspected by the TAA to confirm compliance.

BSCCo will inform the TAA of the percentage of previously non-compliant Metering Systems which should be re-inspected. Re-inspections will be selected with consideration given to the category and number of non-compliances associated with the previous inspection.

The TAA will submit the proposed schedule of re-inspections to BSCCo for approval. At the end of a quarter, the TAA shall select a sample of 10% (or any other percentage as determined by the PAB) of the category 1 non-compliances that a participant has rectified during that quarter and shall carry out a re-inspection.

1.12 Targeted Inspections

Where the PAB requires assurance about a particular Metering System, they may request a targeted inspection to take place.

The PAB will use the following information when deciding to perform a targeted check:

- Previous non compliances;
- Performance related issues;
- Settlement error;
- Information provided by it's sub-committees; or
- The Panel.

1.13 Metering System Inspection

On selection of an appropriate Metering System the TAA shall notify the relevant Registrant, MOA and LDSO prior to the date of the intended Inspection Visit. The Registrant or a nominated representative will be invited to attend the Inspection Visit and shall make all reasonable endeavours to ensure access to all Metering Equipment and will liaise with the LDSO or Transmission Company (if necessary) to arrange such access. The Registrant shall be required to ensure that the MOA and LDSO or Transmission Company (if necessary) will be in attendance and that the person attending the site is technically competent to discuss problems relating to any defects or non-compliances and able to agree the resolution of any defects or non-compliances.

The Registrant shall notify the TAA, prior to the intended Inspection Visit that the MOA will be in attendance. In addition the Registrant will inform the TAA of any other representatives that will be present at the Inspection Visit. Failure to do so will be reported to PAB at the discretion of BSCCo.

A MOA may appoint a competent third party who may attend on their behalf.

For SVA Metering Systems the Registrant shall obtain permission from the appropriate LDSO to gain independent access to the LDSO's equipment associated with the Metering System and the MOA shall allow access to the Meter and associated Metering Equipment for which it is responsible. The LDSO shall accede to such a request in a reasonable timeframe prior to the inspection visit as agreed with the Registrant.

For CVA Metering Systems the Registrant (or its nominated representative) shall provide access to the Metering Equipment during the Inspection Visit.

The TAA may, with the agreement of the BSCCo, arrange for an urgent revisit (SVA and CVA Metering Systems) to be initiated. This will be at the expense of the Registrant if:

(a) The Registrant fails to arrange access on the agreed date and time or access cannot be obtained upon arrival by the TAA; or

(b) The MOA fails to attend an Inspection Visit.

Any costs incurred by the MOA as a result of its attendance at an Inspection Visit shall be met by the MOA.

Where the TAA has gained access to the Metering System but has been unable to complete the Inspection Visit, a result of 'incomplete Inspection Visit' and the reason for non completion will be recorded.

Where the TAA has been unable to gain access to the Metering System a result of 'no access' and the reason for no access will be recorded.

1.14 Additional Metering Equipment Details Required by the TAA

When a Metering System has been selected for inspection, the MOA will be required to provide the following additional Metering Equipment Technical Details prior to the Inspection Visit:

1.14.1 General Information

- Site name
- Site address
- Site telephone number

1.14.2 Accuracy

- Circuit Identifier
- Applicable CoP (including the specific Issue)
- Current applicable Metering Dispensation(s)
- Meter Calibration Certificates

- Current Transformer Test Certificates (including details of manufacturer, type, serial number and class).
- Voltage Transformer Test Certificates (including details of manufacturer, type, serial number and class).
- Applicable Meter Compensation values (including evidence to support the applied values).

The determination of the overall accuracy of Metering Systems requires the provision of all associated measurement transformer errors. Details for the processes to be followed by the various parties for the provision of this information are given in section 4 of this BSCP.

1.14.3 Half Hourly Metering System Functional Information

- Channel Number(s) (for Active Energy)
- Measurement Quantity Id
- Date of First Registration

The HHDC will also be required to provide the Meter Technical Details prior to the Inspection Visit.

1.14.4 Half Hourly Metering System Functional Information

Failure to provide the above information to the TAA within the required timescales as defined in section 4 shall be classified as a non-compliance.

The TAA may request any additional information that is felt necessary and reasonable for any Metering System being audited. This additional information will also be provided by the registrant in a reasonable timeframe prior to the inspection visit where possible.

Where appropriate, all information to be provided to the TAA regarding an Inspection visit should be provided via the electronic online tool provided by the TAA.

1.15 Non-Compliance

The TAA shall raise a non-compliance if, after taking into account any Metering Dispensations:

(a) The requirements of the Code and CSDs are not being adhered to;

(b) The actual configurable Meter parameters are not consistent with the Meter Technical Details recorded in Settlement Systems as provided by the HHDC or CDCA, or MOA prior to the Inspection Visit.

The findings of the Inspection Visit will be recorded on an Inspection Schedule and presented to the MOA at the time of the Inspection Visit. Wherever possible any identified non-compliances shall be rectified by the MOA at the time of the visit.

Categorisation of non compliances

Category 1 Non Compliance	A non-compliance has been identified which is deemed to be currently affecting the quality of data for Settlement purposes
Category 2 Non Compliance	A non-compliance has been identified which is deemed to have the potential to affect the quality of data for Settlement purposes
Observation	A non-compliance has been identified which is deemed neither to affect nor to have the potential to affect the quality of data for Settlement purposes

On completion of an inspection, the TAA shall issue notices of compliance or non-compliance to the Registrant, MOA, HHDC, LDSO and Transmission Company as appropriate and where a non-compliance has been determined, the TAA shall provide the Registrant with the details of the non-compliance.

Where a non-compliance has been determined the Registrant shall be responsible for progressing the rectification of the non-compliance and must submit a rectification plan to the TAA. The Registrant will be required to take all reasonable steps to ensure that the party that can take direct action does so, and that the Registrant pursues that party to the extent necessary. Where the BSCCo deems it necessary, non-compliances not rectified by the Registrant will be reported to the PAB who will decide on further action in accordance with BSCP538, Error and Failure Resolution.

The TAA will provide the Registrant with a reminder if the Registrant has failed to rectify the non-compliance within the required timescales. The reminder will contain all appropriate information about the non-compliance.

1.16 Appeals

Where a non-compliance has been identified, this may be appealed by:

- The Registrant responsible for that Metering System; or
- The relevant MOA, HHDC, LDSO or the Transmission Company on behalf of the Registrant.

The non-compliance can be appealed as follows:

1. Initially to the TAA who will review the appeal and provide a response to the appellant.
2. If unsuccessful in 1, the appellant may pursue the appeal with BSCCo, or withdraw the appeal. If the appeal is not withdrawn, BSCCo will review the appeal and provide a response to the appellant.

3. If unsuccessful in 2, the appellant may pursue the appeal with the Panel, or withdraw the appeal. The Panel may choose to delegate this responsibility to the PAB.

The Registrant (or MOA, HHDC, LDSO or the Transmission Company on behalf of the Registrant) will be required to provide evidence in support of the appeal.

1.17 Rectification Action

The Registrant (or MOA, LDSO, HHDC or the Transmission Company on behalf of the Registrant) will rectify the non-compliance or provide a rectification plan (BSCP27/05), which will detail the appropriate milestones and actions to be taken in order to achieve rectification within the timescales required and set out in section 4.

1.18 Post Rectification Action

Where a Registrant is required to perform testing as per CoP 4, 'Code of Practice for the Calibration, Testing and Commissioning Requirements of Metering Equipment for Settlement Purposes', following the rectification of a non-compliance, the PAA or BSCCo or TAA shall have the option to attend and/or request details of the tests performed.

The costs associated with the rectification of a non-compliance and any subsequent testing shall be borne by the responsible Party.

1.19 Reporting

BSCCo may report the findings of an Inspection Visit and any outstanding non-compliances to the PAB.

1.20 Acronyms and Definitions

1.20.1 List of Acronyms

BSC	Balancing and Settlement Code (The "Code")
BSCCo	Balancing and Settlement Code Company
BSCP	BSC Procedure
CDCA	Central Data Collection Agent
CMRS	Central Meter Registration Service
CoP	Code of Practice
CSD	Code Subsidiary Document
CT	Current Transformer
CVA	Central Volume Allocation
HH	Half Hour
HHDC	Half Hourly Data Collector
HV	High Voltage
LDSO	Licensed Distribution System Operator
LV	Low Voltage

MOA	Meter Operator Agent
MRA	Master Registration Agreement
MSID	Metering System ID
MTD	Meter Technical Details
PAA	Performance Assurance Administrator
PAB	Performance Assurance Board
PAP	Performance Assurance Party (Includes Registrants and Party Agents)
REM	Risk Evaluation Methodology
RER	Risk Evaluation Register
ROP	Risk Operating Plan
RMP	Risk Management Plan
S	Scottish Code of Practice (for Metering Systems registered in Scotland prior to the BETTA Effective Date)
SMRA	Supplier Meter Registration Agent
SMRS	Supplier Meter Registration Service
SVA	Supplier Volume Allocation
TAA	Technical Assurance Agent
VT	Voltage Transformer
WD	Working Day

1.20.2 Definitions

Additional Metering Technical Details – Additional Meter Technical Details not included within the D0268 dataflow or listed in BSCP20, Registration of Metering Systems for CVA.

Inspection Visit – the on site inspection of a Metering System.

A full list of definitions is provided in the Code.

2 Not Used

3 Interface and Timetable Information

3.1 Main Sample Selection Process – CVA and SVA

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.1.1	As specified in section 1.10	Request Metering System Ids and associated information.	BSCCo	CDCA	Relevant information from HH Metering System Id, GSP Group, Registrant, MOA, HHDC and Measurement Class.	As agreed
3.1.2	As specified in section 1.10	Request Metering System Ids and associated information.	TAA	SMRA	Relevant information from HH Metering System Id, GSP Group, Registrant, MOA, HHDC and Measurement Class.	As agreed
3.1.3	Within 10 WD of request in 3.1.1	Provide Half Hourly Metering System Ids and associated information.	CDCA	BSCCo	Relevant information from HH Metering System Id, GSP Group, Registrant, MOA, HHDC and Measurement Class.	As agreed
3.1.4	Within 10 WD of request in 3.1.1	Provide Half Hourly Metering System Ids and associated information.	SMRA	TAA	Relevant information from HH Metering System Id, GSP Group, Registrant, MOA, HHDC and Measurement Class.	As agreed
3.1.5	Upon receipt of data in 3.1.3	Provide the TAA with the data.	BSCCo	TAA	Lists of HH Metering System Ids and associated Registrant and MOA.	As agreed

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.1.6	Within 10 WD of receipt of data in 3.1. 4 and 3.1.53	Randomly select 10% more Metering Systems than will be inspected for the forthcoming Quarter, as agreed by the BSCCo.	TAA		Lists of HH Metering System Ids and associated Registrant and MOA.	Internal process
3.1.7	On completion of 3.1.6 and at least 20 WD prior to the Inspection Visit	Request information.	TAA	MOA CDA Registrant[1] (as necessary)	Meter Technical Details Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	Email / Fax / Letter
3.1.8	Within 10 WD of receipt of TAA request in 3.1.7 as necessary	Provide information (as necessary).	Registrant	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	Email / Fax / Letter

[1] It is the responsibility of the Registrant to provide the requested information to the TAA. However, the MOA can provide the information at the request of the Registrant.

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.1.9	Where CVA: Within 10 WD of receipt of TAA request in 3.1.7 Where SVA: On the day of the Inspection Visit or within 10 WD of receipt of TAA request in 3.1.7	Provide Information.	MOA	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	Email / Fax / Letter
3.1.10	Within 10 WD of receipt of TAA request in 3.1.7	Provide information.	CDCA	TAA	Meter Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	Email / Fax / Letter
3.1.11	Upon receipt of data requested in 3.1.7	Finalise sample of HH Metering System to avoid bias towards any one party or type of Metering Equipment and derive inspection schedule. Collate information required for the inspection. Proceed to Section 3.5 (Inspection Visit).	TAA			Internal process

3.2 Specific Sample Selection Process – SVA Only

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.2.1	At PAB meeting	Agree and notify BSCCo of Specific Sample.	PAB	BSCCo	Number and type of each Metering System to form Specific Sample.	Report / Letter
3.2.2	Within 10 WD of decision at 3.2.1	Request information from each Registrant, MOA and LDSO for all relevant Specific Sample Metering Systems registered in SMRSs.	TAA	Registrant, MOA and LDSO	Information about Specific Sample Metering Systems as requested.	As agreed
3.2.3	Within 20 WD of receipt of request at 3.2.2	Provide information on all Specific Sample Metering Systems as requested.	Registrant, MOA and LDSO	TAA	Information about Specific Sample Metering Systems as requested.	As agreed
3.2.4	Upon receipt of information	Randomly select the agreed number of each type of Metering System which comprises the agreed Specific Sample group.	TAA		Select sample as instructed by BSCCo.	Internal process
3.2.5	At least 20 WD prior to the Inspection Visit	Request information.	TAA	MOA Registrant (as necessary)	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.2.6	At least 20 WD prior to the Inspection Visit	Request information.	TAA	HHDC	Meter Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.2.7	Within 10 WD of receipt of request in 3.2.6 as necessary	Provide information (as necessary).	Registrant	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.2.8	On the day of the Inspection Visit or within 10 WD of receipt of TAA request in 3.2.5	Provide information	MOA	TAA	Meter Technical Details. Additional Metering Equipment Technical Details BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only)	As agreed
3.2.9	Within 10 WD of receipt of request in 3.2.6	Provide information.	HHDC	TAA	Meter Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.2.10	Prior to Inspection Visit	Collate information required for inspection. Proceed to Section 3.5.	TAA			Internal process

3.3 Determination of Metering Systems for Targeted Inspections

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.3.1	At any time	Provide information on SVA Half Hourly or CVA Metering Systems that may require a targeted inspection.	Market Participant, PAA, Panel, PAB or TAA BSCCo	BSCCo	Metering System with reasons and supporting evidence of suspected non-compliance.	As agreed
3.3.2	Within 5 WD of receipt of information in 3.3.1	Determine Metering System that requires a targeted inspection.	BSCCo		Suspected non-compliance.	Internal process
3.3.3	Within 1 WD of 3.3.2.	Instruct the TAA to carry out a targeted inspection and inform the TAA of the urgency.	BSCCo	TAA	Metering System and reason for targeted inspection.	As agreed
3.3.4	At least 20WD prior to the Inspection Visit	Request information.	TAA	MOA Registrant (as necessary)	Meter Technical Details Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.3.5	At least 20WD prior to the Inspection Visit	Request information.	TAA	HHDC or CDCA	Meter Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.3.6	Within 10 WD of receipt of the request in 3.3.4 as necessary	Provide information (as necessary).	Registrants	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.3.7	Where CVA: Within 10 WD of receipt of TAA request in 3.3.4 Where SVA: On the day of the Inspection Visit or within 10 WD of receipt of TAA request in 3.3.4	Provide information.	MOA	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.3.8	Within 10 WD of receipt of the request in 3.3.5	Provide information.	HHDC or CDCA	TAA	Meter Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.3.9	Prior to Inspection Visit	Collate information required for Inspection Visit and proceed to section 3.5.	TAA			Internal process

3.4 Selection of Metering Systems for Re-inspections

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.4.1	On a Quarterly basis	Identify Metering Systems that were found to be non-compliant and have since been notified as rectified. Randomly select Metering Systems in accordance with the percentage agreed by BSCCo.	TAA		Previous inspection history. Percentages as agreed by BSCCo.	Internal process
3.4.2	Within 2 WD of 3.4.1	Provide BSCCo with schedule of proposed re-inspections for authorisation.	TAA	BSCCo	Schedule of proposed re-inspections.	As agreed
3.4.3	Within 2 WD of 3.4.2	Analyse proposed schedule of re-inspections and either agree schedule or request amendments. Go back to 3.4.2 if required.	BSCCo	TAA	Schedule of proposed re-inspections.	As agreed
3.4.4	At least 20WD prior to the Inspection Visit	Request information.	TAA	MOA Registrant (as necessary)	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.4.5	At least 20WD prior to the Inspection Visit	Request information.	TAA	HHDC or CDCA	Meter Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.4.6	Within 10 WD of receipt of request at 3.4.4 as necessary	Provide information (as necessary).	Registrant	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.4.7	Where CVA: Within 10 WD of receipt of TAA request in 3.4.4 Where SVA: On the day of the Inspection Visit or within 10 WD of receipt of TAA request in 3.4.4	Provide information.	MOA	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.4.8	Within 10 WD of receipt of request at 3.4.5	Provide information.	HHDC or CDCA	TAA	Meter Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.4.9	Prior to Inspection Visit	Collate information for Inspection Visit and proceed to Section 3.5.	TAA			Internal process

3.5 Inspection Visit

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.5.1	At least 20 WD[2] prior to an Inspection Visit	Notify Registrant, LDSO and MOA of HH Metering System identified for Inspection Visit.	TAA	Registrant, LDSO and MOA	Date, time and Metering System to be inspected. (as detailed in Appendix 4.5.1 - BSCP27/01)	As agreed
3.5.2	Within 10 WD of receipt of notification in 3.5.1.	Arrange for access to Metering System for the purposes of an Inspection Visit.	Registrant	MOA, Customer, and if necessary LDSO	Date, time and Metering System to be inspected.	As agreed
3.5.3	At least 5WD prior to an Inspection Visit	Notify the TAA and MOA of acceptance of impending Inspection Visit and those parties attending.	Registrant	TAA MOA	Acceptance of terms and required attendees of an impending Inspection Visit. (as detailed in Appendix 4.5.2 - BSCP27/02).	As agreed
3.5.4	At least 5WD prior to an Inspection Visit	Registrant, LDSO, MOA to provide required information to the TAA for the purposes of the Inspection Visit.	Registrant MOA LDSO	TAA	Meter Technical Details. Additional Metering Equipment Technical Details. BSCP514/8.4.8a Complex Site Supplementary Information Form, where applicable (SVA only).	As agreed
3.5.5	On the day of the Inspection Visit	TAA performs Inspection Visit with MOA in attendance.	TAA and MOA			

[2] In the case of Inspection Visits to Metering Systems located offshore, the TAA shall provide a minimum of 90 WD notice. In such cases, where a visit has not taken place within 20 WD of the intended visit date, the TAA shall notify BSCCo, giving reasons for the failure. BSCCo may refer the matter to the Performance Assurance Board.

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.5.6	On completion of Inspection Visit Within 2 WD of completion of the Inspection Visit	TAA produces Inspection Visit findings and determines Metering System compliance. If a category 1 or 2 non compliance identified, initiate process 3.6. If an observation is identified – notify the relevant parties If Inspection Visit is identified as compliant – notify the relevant parties.	TAA	Registrant and MOA, HHDC, LDSO (or Transmission Company) if appropriate	Completed and signed Inspection Schedule	As agreed
3.5.7	Within 2 WD of completion of Inspection Visit	Request current actual consumption data held by the CDCA or HHDC for the same period as recorded during the Inspection Visit.	TAA	CDCA or HHDC	Current actual consumption data held by the CDCA or HHDC for the same HH period.	As agreed
3.5.8	Within 5 WD of receipt of request	Provide HH data requested in 3.5.7.	CDCA or HHDC	TAA	HH data.	As agreed
3.5.9	Within 2 WD of receipt of 3.5.8	TAA performs Consumption Data Comparison Check and produces Inspection Schedule. If a category 1 or 2 non compliance identified, initiate process 3.6. If an observation is identified – notify the relevant parties If Inspection Visit is identified as compliant – notify the relevant parties.	TAA	Registrant and MOA, HHDC, LDSO (or Transmission Company) if appropriate	Completed and signed Inspection Schedule.	As agreed

3.6 Category 1 or 2 Non-Compliance

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.6.1	Within 2WD of an Inspection Visit (3.5.6a)	Notify the Registrant, MOA, and HHDC/CDCA LDSO and Transmission Company as relevant of non-compliance. Notify LDSO where appropriate. If the visit was a targeted visit notify BSCCo.	TAA	Registrant, MOA, HHDC, CDCA, LDSO or Transmission Company if appropriate; BSCCo (for targeted visit only)	Specific details of category 1 or 2 non-compliance (Completed and signed Inspection Schedule).	As agreed
3.6.2	Within 2WD of performing Consumption Data Comparison Check (3.5.9a)	Notify the Registrant, and CDCA/HHDC of non-compliance. If relevant notify the MOA. If the visit was a targeted visit notify BSCCo.	TAA	Registrant, and HHDC/CDCA ; MOA (if appropriate);BSCCo (for targeted visit only)	Specific details of category 1 or 2 non-compliance (Completed and signed Inspection Schedule).	As agreed

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.6.3	Within 1WD of receiving notification in 3.6.1.	Inform the TAA that a non-compliance notification has been received.	Registrant	TAA	Acknowledgement.	Email / Fax / Letter
3.6.4	Within 10WD of receiving non-compliance notification in 3.6.1. Or following 3.6.6, 3.6.8, 3.7.2 or 3.7.3	a) Where the Registrant, MOA, HHDC, CDCA, LDSO or Transmission Company agrees that metering defects are non-compliant; provide a rectification plan to the TAA or rectify the Metering System defects[3] and inform the TAA of action taken. Proceed to Section 3.6.7. b) Where the Registrant or MOA disagrees the non-compliances raised; inform the TAA and follow the appeal process set out in 3.7.	Registrant, MOA, HHDC, CDCA, LDSO or Transmission Company Registrant, MOA	TAA TAA	Details of the Rectification action taken, or a rectification plan (Appendix 4.5.5 - BSCP27/05). Non-compliance appealed and reason for disagreement	Email / Fax / Letter Email / Fax / Letter
3.6.5	On 11th WD after notifying a Registrant of non-compliance	Where an appeal has *not* been received, and no rectification details or plan are received from the Registrant MOA, or HHDC/CDCA, send a reminder notification to the Registrant, MOA, and HHDC/CDCA, requesting a rectification plan or details of the rectification action taken.	TAA	Registrant, MOA or HHDC/CDCA	Details of non-compliance.	Email / Fax / Letter
3.6.6	Within 1WD of receiving notification in Ref. 3.6.5	Inform the TAA that a reminder notification has been received and proceed to 3.6.3.	Registrant, MOA and HHDC/CDCA	TAA	Acknowledgement of reminder notification.	As agreed

[3] It should be noted that it is the responsibility of the Registrant to progress any non-compliances associated with a Settlement Metering System. However, the MOA can progress the rectification of a non-compliance at the request of the Registrant and will follow the actions of the Registrant detailed in this process.

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.6.7	Within 3WD of 3.6.6	Where no rectification plan or details of the rectification action taken are received, escalate the Registrant, MOA, and HHDC/CDCA. Report to BSCCo. Inform the Registrant, MOA, and HHDC/CDCA that they have failed to provide adequate rectification details and will be reported to BSCCo.	TAA TAA	BSCCo Registrant, MOA or HHDC/CDCA		Email / Fax / Letter
3.6.8	Within 2WD of 3.6.4a or following 3.6.9a	Analyse the Information provided. a) Where the Registrant, MOA or HHDC/CDCA has provided adequate information to show rectification action is complete close the non-compliance and notify the Registrant and MOA and HHDC/CDCA. Process ends. b) Where the Registrant, MOA or HHDC/CDCA does not provide: adequate information to show rectification action is complete; or a complete rectification plan; notify the Registrant and, MOA, and HHDC/CDCA with the reasons and proceed to 3.6.3. c) Where the Registrant, MOA or HHDC/CDCA provides an adequate rectification plan, notify the Registrant and MOA and HHDC/CDCA that the plan is satisfactory	TAA	Registrant, MOA and HHDC/CDCA ; and LDSO (if appropriate) Registrant, MOA and HHDC/CDCA ; and LDSO (if appropriate) Registrant, MOA and HHDC/CDCA ; and LDSO (if appropriate)	Rectification plan.	Internal process As agreed As agreed As agreed

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.6.9	As appropriate for the milestones in the rectification plan	Monitor completion of milestones in the rectification plan. Analyse the information required. a) Where the milestones have been met provide confirmation to the Registrant, MOA, HHDC/CDCA, and BSCCo. If the final milestone has been met proceed to 3.6.8a. b) Where the milestones have not been met or no information is received regarding the completion of milestones from the Registrant, MOA or HHDC/CDCA Report to BSCCo. Notify the Registrant and MOA, and HHDC/CDCA that they have failed to meet the timescales of the rectification plan and will be reported to BSCCo.	TAA	Registrant, MOA, HHDC/CDCA and BSCCo BSCCo Registrant, MOA, HHDC/CDCA		Internal process As agreed Email / Fax / Letter Email / Fax / Letter

3.7 Appeal Process

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.7.1	Within 5WD of receipt of appeal details at 3.6.4b.	TAA considers the grounds for the appeal. a) Decide that the appeal is valid and withdraw the non-compliance. Notify the Registrant and/or MOA of the decision and that the issue is now closed. Process ends. b) Decide that the appeal is not valid and inform the Registrant and MOA that the non-compliance will be upheld.	TAA	 Registrant or MOA Registrant or MOA	Reasons why the non-compliance has been appealed Details of why the non compliance has been removed Details of why non-compliance is still valid	Internal process Email / Fax / Letter Email / Fax / Letter
3.7.2	Within 5WD of receiving notification in section 3.7.1b	Registrant or MOA considers appeal decision. a) If Registrant or MOA accept decision; inform TAA and proceed to 4.6.4a. b) If Registrant or MOA still disagree with the non-compliance acknowledge receipt of decision and notify TAA of further appeal. Notify BSCCo of the appeal	Registrant or MOA	 TAA TAA BSCCo	Reasons why the non-compliance has been upheld. Acknowledgement of receipt of appeal decision and further appeal.	Email / Fax / Letter Email / Fax / Letter

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.7.3	Within 20 WD of receipt of the appeal at 3.7.2b	BSCCo considers the grounds for the appeal. a) Decide that the appeal is valid and withdraw the non-compliance. Notify the relevant parties of the decision and that the issue is now closed. Process ends. (b) Decide that the appeal is not valid and inform the relevant parties that the non-compliance will be upheld.	BSCCo	 Registrant, MOA and LDSO (if appropriate); TAA Registrant, MOA and LDSO (if appropriate); TAA	Details of why the non-compliance has been appealed. Details of why the non-compliance has been removed. Details of why non-compliance is still valid.	Internal process Email / Fax / Letter Email / Fax / Letter
3.7.4	Within 5 WD of receiving notification in 3.7.3b	Registrant or MOA considers appeal decision. a) If Registrant or MOA accept decision; inform BSCCo and TAA. Proceed to 3.6.3a. b) If Registrant or MOA still disagree with the non-compliance acknowledge receipt of decision. Notify BSCCo that they wish to present appeal to the Panel[4]. The Registrant or MOA may request attendance at the next PAB/Panel meeting.	Registrant or MOA	 TAA BSCCo BSCCo	Reasons why the non-compliance has been upheld. Acknowledgement of receipt of appeal decision. Reasons why the non-compliance has been appealed.	 Email / Fax / Letter Email / Fax / Letter
3.7.5	Within 1WD of receipt of the appeal details in 3.7.4 b	Notify the TAA of appeal to Panel .	BSCCo	TAA	Reasons why the non-compliance has been appealed.	As agreed

[4] The Panel may delegate this to the PAB.

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.7.6	At next appropriate meeting of the PAB or Panel	BSCCo reports the appeal details to the Panel for decision.	BSCCo	PAB / Panel	Details of non-compliance and details of why the non-compliance has been appealed by the Registrant or MOA	PAB or Panel Paper
3.7.7	At PAB or Panel meeting	Panel considers the grounds of the appeal and decides whether to uphold or withdraw the non-compliance.	PAB / Panel		Report from the TAA and BSCCo.	
		(a) PAB/Panel decides that the appeal is valid and informs the relevant parties to withdraw the non-compliance. Process ends.	PAB / Panel via BSCCo	Registrant, MOA and LDSO (if appropriate); TAA	The PAB / Panel's decision and reasons why the appeal has been accepted.	Email / Fax / Letter
		(b) PAB/Panel decides that the appeal is not valid and informs the relevant parties to continue with the non-compliance procedure. Proceed to 3.6.3a.	PAB / Panel via BSCCo	Registrant and MOA; TAA	The PAB / Panel's decision and reasons why the appeal has not been accepted.	Email / Fax / Letter

3.8 Reporting

REF	WHEN	ACTION	FROM	TO	INFORMATION REQUIRED	METHOD
3.8.1	Monthly	Provide BSCCo with a report of the results of all Inspection Visits completed in the previous month and details of all outstanding non-compliances.	TAA	BSCCo		As agreed
3.8.2	On or before PAB paper day	Provide the PAB with details of Inspection Visits completed by the TAA in the previous month and details of all outstanding non-compliances.	BSCCo	PAB		Report
3.8.3	At the PAB meeting	Determine what action, if any, needs to be taken in respect of a non-compliant Registrant. The PAB may also choose to initiate the Removal of Qualification Process for a MOA.	PAB		Details of Inspection Visits completed by the TAA in the previous month and details of all outstanding non-compliances.	Removal of Qualification Process is defined in BSCP537.

4 Appendices

4.1 Description of Inspection Checks

This appendix describes the tests & checks that may be required to be carried out by the TAA as part of an Inspection Visit, as determined by the PAB. This is not an exhaustive list.

4.1.1 Measurement Transformer Specification (where appropriate)

Where possible check the:

(a) Ratio, class, rated burden and polarity from the labels physically attached to the measurement transformers and/or the identification plates attached to switchgear or other enclosures containing measurement transformers (in practice this will not always be practical for safety reasons). And

(b) Test records/certificates detailing specific measured errors held by the LDSO, or equipment owner, associated with the measurement transformers on site or from agreed Generic CT/VT certificates (SVA) in the case of CTs and VTs.

4.1.2 Meter Technical Details

Check to ensure that the actual Meter Technical Details conform to those recorded in Settlement Systems using:

(a) Information provided by the CDCA (CVA), Registrant (SVA) or Party Agent in accordance with Section 1.14 of this BSCP, including any measurement transformer error offsets & commissioning details.

(b) Information supplied to the CDCA, HHDC and MOA.

(This may require a remote/local interrogation of data for comparison purposes).

4.1.3 Accuracy

The following checks should be performed to verify the overall accuracy requirements of the Metering System:

(a) Measurement transformers relate to test certificates provided;

(b) Meter - test certificate calibration details are in accordance with requirements in CoP Four;

(c) Metering Equipment installed is in accordance with the relevant CoP.

The overall accuracy is to be determined by the TAA and shall be within the requirements of the applicable CoP.

4.1.4 Correct Energy Measurement Check

To verify that the Metering System is recording the correct amount of energy, checks shall be carried out that compare the primary load with that being recorded by the Metering System. However, due to the possible restrictive physical location

of the primary conductors and Plant at an installation, access may be limited. Where this is the case, other suitable methods may be used to determine correct measurement.

For SVA sites installations can be divided up into the following three categories:

(a) LV whole current;

(b) LV, CT operated;

(c) HV, CT & VT operated.

Sites that fall into categories (a) and (b) will prove to be the most accessible for prevailing load checks. Sites in category (c) may be more difficult to access, but it is often possible to use a clip-on ammeter around the current transformer cables where access to switchgear is restricted.

Note: When all preferred methods of checking the prevailing load fails, other suitable engineering methods may be adopted to establish correct measurement.

Methods of establishing primary load (in order of preference):

1. The demand (derived from independently measured primary values) shall be compared to the Meter's instantaneous demand reading for the same period; or

2. The demand (derived from independently measured secondary values where the primary/secondary ratios can be established) shall be compared to the Meter's demand reading for the same period; or

3. Where appropriate an alternative measurement device shall be used for comparison with that of the Settlement Meter; or

4. The MOA shall provide the TAA with appropriate commissioning records. The TAA is required to establish that these details sufficiently verify that the Meter has been proven to be operating correctly during commissioning; or

5. In the event that none of the above is possible, the TAA will notify BSCCo giving the reasons. (This recognises that if 1 to 4 are not possible additional checks do not add value.)

4.1.5 Consumption Data Comparison Check

The TAA shall compare the metered energy data for one half hour recorded at the time of the Inspection Visit with the consumption data held by the HHDC or CDCA for that same half-hour period. If the values differ by more than agreed tolerances the TAA will issue a non-compliance. This check can take place on site or off site at the discretion of the TAA and either method forms part of the Inspection Visit.

The tolerances will be agreed from time to time by the PAB.

In order to obtain and verify stored Meter data values that are eventually transferred to the HHDC or CDCA, it will be necessary to use a Hand Held Unit running relevant approved Hand Held Unit protocol to download from the Meter or Outstation. This process will also provide engineering units (kW half hours and/or raw pulses) and some standing data. Once the pulse multiplier and Meter constant are applied (where applicable) these values can be compared with the measured values.

This Consumption Data Comparison Check shall take the following format:

1. Compare the Meter Technical Details provided by both the HHDC or CDCA and MOA with that observed on-site. Consideration should also be given to Commissioning and historic proving test information.

2. Request the current actual consumption data held by the CDCA or HHDC for the same half hour period to compare energy recorded by the Settlement Meter and the energy values held in the CDCA or HHDC systems which will be submitted to Settlement.

In both cases one Active Energy channel will be requested unless a non-compliance is identified.

4.1.6 Code of Practice Compliance

All points to be checked as specified in the appropriate CoP.

4.1.7 Quality of Installation

All points to be checked as specified in the applicable CoP, including:

(a) Labelling of equipment.

(b) General standard of installation i.e. good working practice.

4.1.8 The TAA will perform an estimated metered error calculation to be included in the Annual Report to the PAB to provide an indication of the impact on settlements, in particular the impact that category 1 non-compliances may be having.

4.2 Not Used

4.3 Provision of Measurement Transformer Certificates for Metering Equipment

4.3.1 Objective

BSC Parties require assurance that Metering Equipment operates within the accuracy limits defined in the appropriate CoP. As part of the process of establishing this assurance, evidence is required of the measurement transformer errors associated with the Metering System. This section explains the process involved in achieving such assurance.

4.3.2 Ownership

In the context of this BSCP, Equipment Owner is defined as the owner of the measurement transformers which form part of the Metering System.

4.3.3 Responsibilities

The MOA responsibilities are as stated in the Code and Code Subsidiary Documents.

The Equipment Owners responsibilities regarding the provision of measurement transformer certificates and co-operation with the MOA, are stated in the Code and Code Subsidiary Documents.

4.3.4 Procedures for CoP1,CoP2, S1 and S2

The MOA should obtain the necessary measurement transformer test certificates from the Equipment Owner. This should be provided within 10 WD of the request.

If the necessary test certificates are not immediately available, the Equipment Owner shall advise the MOA of that situation (within 10 WD of the request) and state what steps are being taken to obtain the test certificates associated with the measurement transformers for that circuit/Site.

If the Equipment Owner does not have the necessary test certificates readily available, the Equipment Owner should request copies of the original test certificates. Where these are obtained, they should then be supplied to the MOA as soon as possible after the request from the MOA.

If the required test certificates are not available, the Equipment Owner must either:

(a) Quote errors for a measurement transformer of similar characteristics, e.g. accuracy class, ratio, burden rating, manufacturer, type, age, etc; or

(b) Obtain measurement transformer errors by testing; or

(c) Replace the installed units by units with known errors at the earliest opportunity.

In either of (a) or (b) above, the Equipment Owner shall provide evidence to support the errors provided. This information shall be passed to the MOA within a further period of 10 WD of the errors being established.

The MOA will, as required, provide to the TAA the information supplied by the Equipment Owner.

4.3.5 Procedures for CoP3, CoP5, S3 and S5

The MOA should obtain the necessary measurement transformer error certificates from the Equipment Owner. This should be provided within 10 WD of the request.[5]

If the necessary error certificates are not readily available the Equipment Owner must provide the MOA, (still within the 10 WD of the request), with one of the following:

- Copies of the original certificates
- A generic certificate.

A generic certificate needs to be approved by the Panel. In order to approve a generic certificate, the Panel requires evidence that the statistical analysis method used is robust. The statistical analysis needs to be specific to ratio, make, rating, class and type.

When carrying out an audit the TAA will ask the MOA for the measurement transformer error certificates. The MOA will provide to the TAA, the information provided by the LDSO.

4.4 Details of Forms for use in Technical Assurance

For the purposes of Technical Assurance the following forms can be utilised. However all exchange of information required[6] is encouraged through the use of the electronic online tool, as provided by the TAA:

BSCP27/01 - Notification of an Inspection Visit.

BSCP27/02 - Confirmation of Attendance at Technical Assurance Inspection Visit.

BSCP27/03 – No longer used

BSCP27/04 – No longer used

BSCP27/05 - Rectification Plan

4.4.1 Notice of Inspection Visit – BSCP27/01

This form, BSCP27/01, is used by the TAA to inform the Registrant of impending Inspection Visits. It contains the date, time and Site address for the Inspection Visit. The Registrant is required to respond to this notice in a timely manner; failure to do so may result in the matter being escalated to the PAB.

[5] Where the LV CTs are of accuracy class 0.5 or below the TAA will not require the MOA to obtain the CT certificates and the error shall be deemed that of the accuracy class in both directions for the purpose of establishing the overall error.

[6] The TAA is able to request any additional information in relation to any Metering System, and is not restricted to the Metering Systems which are being physically audited.

4.4.2 Confirmation of Attendance – BSCP27/02

This form, BSCP27/02, is used by the Registrant to confirm attendance at an impending Inspection Visit and acceptance of the arrangements requested by the TAA. It is sent in response to a BSCP27/01 form. Failure to respond to this confirmation in a timely manner may be reported to the PAB.

4.4.3 Inspection Schedule for Half Hourly Metering Systems – Part 1 – BSCP27/03

No longer used.

4.4.4 Inspection Schedule for Half Hourly Metering Systems – Part 2 – BSCP27/04

No longer used.

4.4.5 Rectification Plan – BSCP27/05

This form is used by the Registrant or MOA to provide details to the TAA and/or BSCCo of the action that the party intends to take in order to rectify the non-compliance. Details of all relevant milestones should also be included.

4.5 Forms

Details of all forms follow below in section 4.5.1.

All forms must contain the information stipulated.

4.5.1 BSCP27/01 - Notification of Inspection Visit SVA / CVA

The form must contain the following data items:

Contact Details:

- To
- From
- Email address

Date

Number of Pages (only if Faxing)

List of planned Inspection Visits with the following details:

- Date
- Time
- MSID
- Visit Ref
- Site Name / Address
- Attendees

Details that the Registrant must send or facilitate sending prior to the Inspection Visit:

- Meter Test Certificates for all listed MSIDs
- Test Certificates for all Measurement Transformers for all listed MSIDs
- Commissioning documentation
- Compensation calculations (including Transformer Losses, etc), on a circuit by circuit basis
- Metering Equipment Alarm reporting procedure
- And all other reasonable requests made by the TAA

The TAA must stipulate which areas it will require access to, e.g. Metering Equipment Room, Central Control Room, Gen Alternator Pit, Gen VT Chamber, CT / VT's, substations (this list is not exhaustive).

4.5.2 BSCP27/02 - Confirmation of Attendance at Technical Assurance Visit

The form must contain the following data items:

Contact Details:

- To
- From
- Email address

Date

Number of Pages (only if Faxing)

Written confirmation of Attendance at the TAA visit

Contact details for the site (per MSID):

- MSID
- Contact
- Company
- Telephone Number
- TAA visit Reference

Attending Parties:

- Meter Operator Agent Contact
- Registrant Contact
- LDSO Contact
- Customer Contact

4.5.3 BSCP27/03 - Not used

4.5.4 BSCP27/04 - Not used

4.5.5 BSCP27/05 - Rectification Plan Proforma

The form must contain the following data items:

Registrant

MOA

HHDC

LDSO

Contact Details:

- Telephone number
- Email address

MSID

TAA Site Visit Reference

Registrant Ref Number

Site Name & Address

Non Compliances - 1 rectification plan per non compliance:

- Category
- Associated Rectification Action
- Target date for completion
- Key Milestones (e.g. MTDs provided by specific date)
- Where the responsibility is for completing the action

CDCA Service Description version 15 Red line Extract

8. COLLECTION OF METERING SYSTEM DATA

8.5 make provisions to collect the Meter period data manually, by visit to site, where collection of Meter period data via a communication link is not possible. Where the Meters are located at an Offshore Power Park Module, make arrangements, as agreed with the Registrant, to collect the Meter period data manually.

12. METER ADVANCE RECONCILIATIONS

The CDCA shall:-

12.1. produce a Meter Reading Schedule for each Metering System on an annual basis, at least three months ahead of the commencement of that Meter Reading Schedule and forward to the Registrant of the Metering System and the relevant MOA;

12.2. schedule Meter reading visits as follows:

- at least every 12 months for Meters with integral Outstations that provide a cumulative reading of the prime Meter register equivalent to the total consumption or production of that Meter;
- at least every 6 months for other Meters with integral Outstations; ~~and~~
- at least every 3 months for Meters with external Outstations~~.~~; and
- for Meters, with external Outstations, located at Offshore Power Park Modules:
  - within 3 Months of commencement of the Meter Reading Schedule for the first Meter reading visit; and
  - at least every 12 months for each Meter reading visit thereafter.

12.3. keep a list of which Meters qualify for which frequency of visit;~~.~~

12.4 ensure, or procure that Meter reading is carried out on the registers of all physical Meters recording active energy and the active energy registers of associated data collector outstations, where applicable, which provide Meter period data collected by the CDCA for Settlement purposes, in accordance with Section 12.2;

CDCA User Requirements Specification Issue 15 red line extract

5.13 CDCA-F013: Undertake Meter Advance Reconciliation

Requirement ID: CDCA-F013	**Status:** M	**Title:** Undertake Meter Advance Reconciliation	**ITT reference:** CDCA SD 12.2 - 12.6, 12.11, 19.2 BPM 3.8, 4.12, 4.2 CP1153
Man/auto: Manual	**Frequency:** As per Functional Requirements 1., 2., ~~&~~ 3.~~ &~~ 4.	**Volumes:** Approximately 100 per working day, based upon 5000 metering systems.	

Functional Requirement:

1. For Meters with separate Outstations the CDCA shall ensure that meter reading is carried out on the registers of all physical meters recording active energy and the active energy registers of associated data collector outstations, where applicable, which provide meter period data collected by the CDCA for settlement purposes, at least once every three months.

2. For Meters with separate Outstations located at Offshore Power Park Modules the CDCA shall ensure that meter reading is carried out on the registers of all physical meters recording active energy and the active energy registers of associated data collector outstations, where applicable, which provide meter period data collected by the CDCA for settlement purposes, at three months for the first Meter Advance Reconciliation and thereafter at least once every twelve months.

~~2.~~3. For Meters with integral Outstations that do not provide an electronic cumulative reading of the prime Meter register equivalent to the total consumption or production of the Meter, the CDCA shall ensure that meter reading is carried out on the registers of all physical meters recording active energy, which provide meter period data collected by the CDCA for settlement purposes, at least once every six months.

~~3.~~4. For Meters with integral Outstations that provide an electronic cumulative reading of the prime Meter register equivalent to the total consumption or production of the Meter, the CDCA shall ensure that meter reading is carried out on the registers of all physical meters recording active energy, which provide meter period data collected by the CDCA for settlement purposes, at least once every twelve months.

~~4.~~5. All records of active energy meter readings shall be input into the Meter Advance Reconciliation process, recording the relevant dates and times of readings, and comparing the advance of the register reading with the sums of the meter period data relevant to that register reading over the same time period.

~~5.~~6. The CDCA shall validate that the time at which the physical meter reading was taken as either in Universal Co-ordinated Time or local clock time and take this potential variation into account when comparing the sum of half-hourly values in the reconciliation. Note that the meters themselves always operate using a U~~C~~TC time reference (i.e. GMT).

The results of each Meter Advance Reconciliation shall be validated, and the CDCA shall provide the relevant BSC Party (the Registrant) with a reconciliation report detailing the actual difference calculated for each active energy meter or associated outstation register. The report may also be supplied to the relevant MOA, and the Distribution business if required, and to the BSCCo Ltd if needed to support a dispute.

Non Functional Requirement:

The CDCA shall in all cases, ensure that authorisation for access is granted to procure meter readings.

When attending a site to perform a meter reading for MAR purposes, the CDCA shall also perform visual inspections to ensure that:-

a) there is no evidence of damage to the Metering Equipment;
b) there is no evidence of fuse failure;

c) all indicator lamps are operational;
d) there is no evidence of tampering with the Metering Equipment;
e) there is no evidence of safety measures being compromised; and
f) the appropriate metering seals are correctly applied to the Metering Equipment in accordance with prescribed standards which will be equivalent to Appendix 8 of Schedule 5 of the Meter Operation Code of Practice Agreement.

Interfaces:

This is to be in accordance with interface requirement CDCA-I011 for incoming dial readings, and CDCA-I018 for reporting. Meter period data is collected using interfaces CDCA-I008 (for automatically collected data) and CDCA-I009 (for manually collected period data).

Issues:

CP1323 Redlining Amendments following PAB109/06

Amend the redlining in Sections 8.1.15, 9.1.8, 10.1.4, 11.1.4, 12.1.5, 13.1.5, 14.1.5, and 18.1.6 of the draft BSCP537 Appendix 1 'Self-Assessment Document' extract for CP1323 as follows:

The response should address the following:

1. Calculations are in accordance in with the calculation guidelines specified in BSCP533 Appendix A
2. Submissions in accordance with the specified timescales/calendar to PAA@elexon.co.uk
3. Data is submitted in the required file format specification (in accordance of BSCP533 Appendix A PARMS Text File Formats)
4. Controls in place for data validity and completeness

Demonstration of a full understanding of, and capability to fulfil, the obligations and requirements of PARMS.