Issue Report

Issue 54 'Discrepancies between the points of measurement required in the BSC and the Code of Practices and the physical points of connection'

This Issue looks to consider the current discrepancies between where the BSC requires measurements of energy for Settlement purposes to be made and where the CoPs require overall accuracy to be maintained. This could result in many applications for Metering Dispensations where the actual points of connection do not coincide with the Defined Metering Point.

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About This Document

This document is the Issue 54 Group's Report to the BSC Panel. ELEXON will table this report at the Panel's meeting on 12 June 2014.

Any questions?

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1 Summary

Background

ELEXON has identified discrepancies between the points of measurement required in the Balancing and Settlement Code (BSC) and in the Half Hourly (HH) Codes of Practice (CoPs), and the actual physical points of connection at certain types of sites. These discrepancies can potentially cause more Metering Dispensation applications which can result in additional associated time and resource. As such, ELEXON proposed some potential solutions to the Imbalance Settlement Group (ISG) as detailed in section 2 regarding the following three areas:

1. Location of Defined Metering Point (DMP) between a single Licenced Distribution System Operator (LDSO) and the Transmission System operator (TSO) is currently defined as "at the lower voltage side of the supergrid connected transformer" (SGT);

2. Location of DMP between Generating Plant and the TSO is currently defined as "at the high voltage side of the generator and station transformers"; and

3. One DMP description is very specific about the location of the DMP for two Interconnectors, and does not include any reference to any other existing Interconnectors.

The ISG recommended that a Standing Issue be raised to discuss potential solutions to the above concerns. In addition, the ISG also recommended that consideration be given to validating compensation values as an additional item for the Group to consider.

Conclusions

The Issue 54 Group agreed with ELEXON's proposals that changes are required to:

- change the DMP for a single LDSO connecting to the Transmission System to be "at the point of connection" and create a generic Metering Dispensation for where Metering Equipment cannot be located at the point of connection for practical reasons for the above, but within an agreed distance;

- change the DMP for Generating Plant connecting to the Transmission System to be "at the point of connection" to remove any ambiguity about where Metering Equipment needs to be installed;

- create a generic definition for the Interconnector DMPs as "at the point(s) of connection to the TSO" to prevent the need for further changes to the HH CoPs; and

- create a standard methodology for power transformer or line loss compensation where the Actual Metering Point (AMP) is not at the DMP, and seek to involve the Technical Assurance Agent (TAA) in validating these during the Metering Dispensation application process where required.

2 Background

Discrepancies between BSC and CoP requirements

In November 2013 ELEXON presented a paper to the ISG (ISG151/01) outlining its concerns about discrepancies between the BSC requirement to measure flows of electricity at Systems Connection Points (SCPs) and Boundary Points (BPs) to the Total System[1], and where the HH CoPs require flows to be measured (DMP). It was highlighted that at certain types of sites, e.g. for Transmission System connections, the actual physical points of connection differ from the DMP. ELEXON proposed some potential solutions (as detailed below) to the BSC and DMP discrepancies including updating the DMP for Interconnectors to either be more generic than it is currently or by adding descriptions of new Interconnectors to it.

The ISG suggested that ELEXON discuss the issues and solutions presented to it further at an industry forum and also expressed concern about the lack of validation of power transformer or line loss compensation factors as part of the Metering Dispensation application process. This Issue was raised to consider the issues and potential solutions further, and the ISG's concern about validating loss correction factors as part of the Metering Dispensation application process.

BSC requirements

BSC Section K 'Classification and Registration of Metering Systems and BM Units' requires Parties who are responsible for flows of electricity (i.e. imports and exports) between Systems at SCPs and the flows of electricity (i.e. Imports and Exports) to or from Plant or Apparatus connected to the Total System at BPs to be measured and recorded by compliant Metering Equipment.

Section L 'Metering' requires Metering Equipment to comply with the relevant metering Code of Practice at the time the Metering Equipment is first registered for Settlement as a Metering System or be the subject of, and comply with, a Metering Dispensation. The Metering Dispensation process is set out in BSC Procedure (BSCP) 32 'Metering Dispensations' and Metering Dispensation applications need to be approved by the BSC Panel. The BSC Panel has delegated its responsibility for approving Metering Dispensations to the ISG and the Supplier Volume Allocation Group (SVG). This process can take six to eight weeks as applications need to be validated by ELEXON, reviewed by an industry expert group and may need to be presented for approval to both the ISG and the SVG, depending on the applicable CoP2.

CoP requirements

As well as defining the accuracy class of individual items of Metering Equipment, the CoPs also define the points at which measurement of electricity is required and the limits of overall accuracy of measurement required at these points. These points of measurement are called the DMPs and are set out in Appendix A of the HH CoPs. Metering Equipment cannot always be installed at the DMP for practical or financial reasons, so where the AMP does not coincide with the DMP a Metering Dispensation needs to be approved.

[1] The Total System is defined in Section X Annex X-1 as the Transmission System, each Offshore Transmission System User Asset and each Distribution System. The Total System was updated by P294 'Addition of Offshore Transmission System and OTSUA to the definition of the Total System' to include 'each Offshore Transmission System User Asset' in December 2013.

[2] The ISG is responsible for CoPs 1-4 and the SVG is responsible for CoPs 3-10.

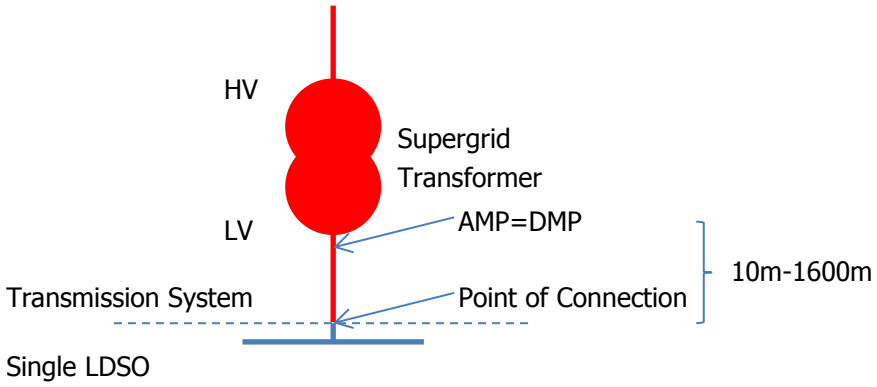
Compensation for electrical losses, in power transformers or lines, to the DMP needs to be considered and, if required, implemented in the Meter itself or in the Data Collector's (DC's) system (e.g. via the Aggregation Rule for Central Volume Allocation (CVA) registered Metering Systems). Similarly, if Metering Equipment can be installed at the DMP but this does not coincide with the point of connection a Metering Dispensation may need to be approved to correct for losses from the DMP to the point of connection. It is the responsibility of the Registrant to seek a Dispensation to correct for losses from the DMP to the point of connection. However, they may not want to correct for losses to the point of connection as arguably the metering is in the correct place from a CoP point of view and the distance may be minimal.

The majority of the DMPs listed in Appendix A of the HH CoPs are defined as "at the points of connection" between Systems (i.e. at SCPs) or between Systems and Customers or Generating Plant (i.e. at BPs). However, two exceptions have been identified as detailed below.

What is the issue?

Location of DMP between a single LDSO and the TSO

One exception identified is between the TSO and a single LDSO (with no other parties connected) where the DMP is defined as "at the lower voltage side of the supergrid connected transformer" (SGT). Here the AMP is at the DMP, however the point of connection between the Transmission System and the LDSO does not coincide with the DMP as detailed in the diagram below:



ELEXON has received six separate[3] Metering Dispensation applications[4] in the past three years which are directly related to Grid Supply Point (GSP) Metering Equipment being located at the DMP for new SGTs but where the DMP does not coincide with the point of connection. The Registrant (i.e. the LDSO) has in each of these cases requested a Metering Dispensation to compensate measurements made for losses in the line or cable to the point of connection.

National Grid maintains a Transmission System Boundary (TSB) registrations tracker spreadsheet detailing upcoming new GSPs, new[5] circuits at existing GSPs and new Transmission System BPs (TSBPs). At present, the tracker indicates that from now until the end of 2015, seven brand new GSPs will be added, 30 new circuits will be added at existing GSPs and there will also be at least 14 new TSBPs in the next three years. The

[3] Eight in total due to two additional temporary Metering Dispensations being granted for Barking West GSP.
[4] Leicester Road GSP, Tilbury GSP, Beddington GSP (pending), Bramford GSP, Barking West GSP and Bredbury GSP.
[5] This includes 'like for like' replacement SGTs which could potentially change the circuit length and/or location of metering current and voltage transformers for the circuit to the point of connection with the LDSO.

new GSPs and new circuits at existing GSPs could potentially[6] result in many applications for Metering Dispensations in order for the Registrant to correct for losses between the DMP and the point of connection.

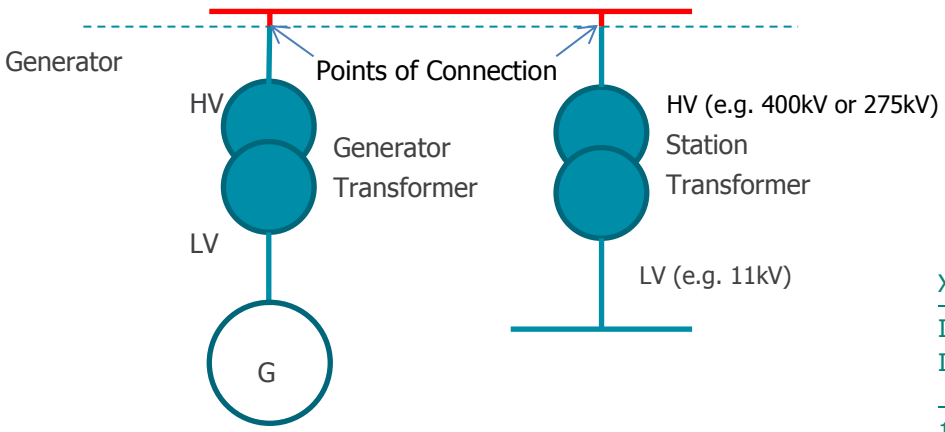
Applications for Metering Dispensations take time and resource from the Registrant, ELEXON, the Metering Dispensation Review Group (MDRG) and the relevant BSC Panel Committee(s) to progress. ELEXON's proposed solution to the issue in its paper to the ISG suggested that a Change Proposal (CP) be raised to change the DMP for a single LDSO connecting to the Transmission System to be "at the point of connection", and for a generic Metering Dispensation to be created for line or cable loss compensation in these cases. The ISG noted that this would shorten the process, enabling a more efficient registration process if the Metering Equipment cannot be installed at the point of connection for practical or financial reasons, where this is the only non-compliance.

The ISG expressed some concern that loss correction factors were not currently validated when Metering Dispensations are granted. ELEXON agreed that by reviewing the loss compensation as part of both the proposed generic Metering Dispensation, for line loss correction only, and site specific Metering Dispensations, where power transformer or line loss compensation is required, additional assurance can be provided that Settlement is being protected and electrical losses attributed to the relevant Party. ELEXON suggested that the MDRG may be best placed to confirm loss correction factors for site specific Metering Dispensations, where appropriate, and that the MDRG could also be included in a review process for the proposed generic Metering Dispensation.

Location of DMP between Generating Plant and the TSO

The second exception identified is between the TSO and Generating Plant where the DMP is defined as "at the high voltage side of the generator and station transformers". This is typically the point of connection in England and Wales, but where measurement takes place on the low voltage (LV) side of the Generator Transformers and Station Transformers compensation has been applied to the commercial interface on the high voltage side (under the old Alpha CoPs) or Metering Dispensations have been approved (which is less common) to do so under the Numeric CoPs. This is detailed in the diagram below:

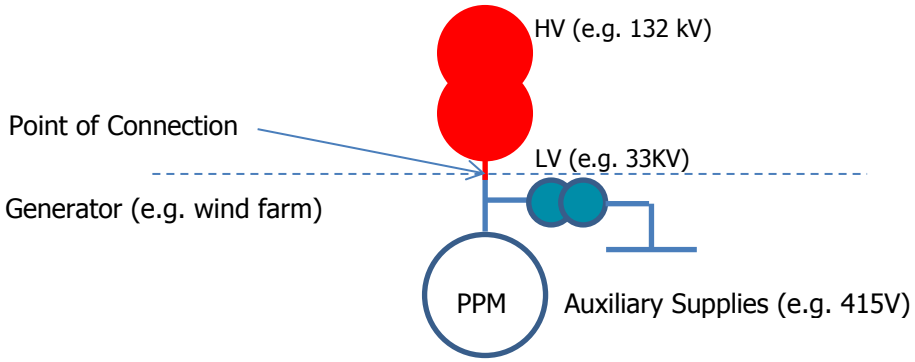
Transmission System (England and Wales)



[6] The distance between the measurement transformers and the point of connection being a key factor in determining whether the Registrant would wish to correct for any losses between them. These are confirmed during the registration of each new circuit and are difficult and time consuming to identify up front.

In Scotland it is usual for TSOs to provide the power transformer that connects Generating Plant (e.g. wind farms) to their systems, and Metering Equipment is installed on the lower voltage side of these power transformers at the point of connection. This is detailed in the diagram below:

Transmission System (Scotland)



As part of the British Electricity Trading and Transmission Arrangements (BETTA), 18 Metering Dispensations[7] were approved by the Authority for existing Generating Plant in Scotland to leave metering on the low voltage side of Transmission System connected transformers. While the majority of new Transmission System connections in Scotland since 2005 are measuring flows at the registered Boundary Points (consistent with the BSC itself) they arguably should be metered on the high voltage side of these power transformers and seeking a Metering Dispensation to compensate for losses to the point of connection (to be consistent with the CoPs).

By changing the DMP for Generating Plant connecting to the Transmission System to the point of connection, any ambiguity about where Metering Equipment needs to be installed will be removed. Prospectively, the requirement to install Metering Equipment on the higher voltage side of the Scottish TSO's power transformer and apply for a site specific Metering Dispensation for power transformer and, possibly, line or cable loss compensation to the point of connection on the low voltage side will also be removed.

In its paper to the ISG, ELEXON suggested that a CP be raised to change the DMP for a Generator connecting to the Transmission System to be "at the point of connection" and leave the issue of who provides the power transformers to other industry Codes and the Authority.

Location of DMP for Interconnectors

In addition to the two exceptions identified above, one DMP description is very specific about the location of the DMP for two Interconnectors, and does not include any reference to any other existing Interconnectors, i.e. between the TSO and an External System. The DMPs are specifically defined as certain points on circuits at the Sellindge (for the Anglo French Interconnector) and Auchencrosh (for the Moyle Interconnector) substations. However, two current Interconnectors, BritNed and East-West, are not captured.

It is anticipated that many new Interconnectors will be connected to the Total System in the future as networks become more integrated throughout Europe, so it would be prudent to update the CoPs to clearly state the DMPs for all the Interconnectors and,

[7] Section I, Table C of the BSC details these.

ideally, remove the specific references to existing Interconnectors to prevent the need for further changes to the HH CoPs.

In its paper to the ISG, ELEXON suggested two possible CP options to addressing this situation:

- either a CP to add in the new Interconnectors and define their DMPs specifically with reference to their individual circuits; or
- a CP to define the DMP as "at the point(s) of connection to the Transmission System operator", to future proof this aspect of the HH CoPs.

3 Issue Group's Discussions

Location of DMP between a single LDSO and the TSO

The Issue Group discussed the first exception where the DMP between the TSO and a single LDSO is defined as "at the lower voltage side of the supergrid connected transformer". ELEXON suggested changing the DMP for a single LDSO connecting to the Transmission System to the "point of connection" and creating a generic Metering Dispensation for line or cable loss compensation. This would mean that the Metering Dispensation application process can be shortened, if measurement could not be made at the physical point of connection, which would enable a more efficient registration process for such non-compliant Metering Systems. By also reviewing loss compensation as part of both the proposed generic Metering Dispensation and site specific Metering Dispensations, where power transformers or line or cable loss compensation is required, additional assurance can be provided that Settlement is being protected and electrical losses attributed to the relevant Party.

Members of the Group agreed with ELEXON's proposal to make the DMP the point of connection and considered three potential options for compensating for losses using:

1. the Meter itself;
2. Line Loss Factors (LLFs) in the Aggregation Rule; or
3. Loss adjustment factors (LAFs) in the Aggregation Rule.

The Group commented that not all Meter types allow you to put in certain types of compensation e.g. dynamic (as opposed to constant) compensation factors over the entire current range or power transformer compensation. The Group also highlighted that LLFs are easier to apply to compensate the Metering System as they are re-calculated by taking into consideration the line lengths, line type, cable lengths, cable type etc., but noted that they would have to go through the LLF Audit process as defined in BSCP128 'Production, Submission, Audit and Approval of Line Loss Factors'.

A member of the Group suggested using the pulse multiplier. Some Meters produce a train of pulses and these pulses are stored in the Meter's Outstation for later retrieval by the DC. Each pulse represents a certain amount of energy that has flowed through the circuit being measured by the Meter. The pulse multiplier is used in the data collection system to convert the pulse count per half hour back into energy values. Some members expressed concern that a pulse multiplier tends to be an integer which may cause resolution problems, and therefore it may be more appropriate to compensate the Meter itself. A member of the Group commented that a pulse multiplier would in practice not be any different to loss adjustment. The Group pointed out that most new Meters (with integral Outstations) do not produce pulses for their associated Outstation, but instead store energy values per half hour.

A member of the Group commented that within the Meter itself is not a sensible place for compensating for losses. This is because there is no agreed standard for recording that such adjustments exist and what the values are, and with time and changes of MOAs etc. this knowledge is lost. ELEXON commented that whilst it may not be sensible to put loss compensation into the Meter, it should arguably be more accurate to compensate the Meter itself. LAFs can only be input as a constant for every Settlement Period while LLFs are meant for embedded CVA BM Units or Distribution System Connection Points (DSCPs) (which go through the BSCP128 process). Meter compensations for power transformer or line losses could be agreed as part of the Metering Dispensation process going forward, in

a generic one or otherwise, and when suitably enacted in BSCP32, would provide another source of getting hold of the agreed (at that time) figures. Any changes to compensation under a Metering Dispensation would need to be notified as an update to ELEXON as the conditions upon which it was granted would have changed.

A member of the Group suggested using the Aggregation Rule and LAFs, but noted that this would require a central system change in order to have something similar to LLFs, which can allow different factors to be applied to each Settlement Period for different times of the year. However, the Group agreed that this would be noticeably costly for industry. The Group also agreed that a lot of testing would need to be carried out to check that there would be no unintended consequences. Overall, the Group agreed that although this change would be good in principle, it would be too costly in practice to pursue as an option.

The Group noted the ISG's concerns that loss correction factors are not currently validated when Metering Dispensations are granted. It also noted ELEXON's original suggestion that the MDRG may be best placed to confirm loss correction factors for site specific Metering Dispensations, where appropriate, and that the MDRG could also be included in a review process for the proposed generic Metering Dispensation. The Group commented that the application process for Metering Dispensations is burdensome as applications go to the MDRG for up to two weeks (which can be even longer if the MDRG has a lot to process at a particular time) and then to the ISG for approval, which can take up to six weeks. As the MDRG is a voluntary group, the additional burden of validating compensation factors may not be supported by their companies. The Group agreed that a generic Metering Dispensation would be the best solution for these scenarios and that the TAA would probably be best placed to validate compensation factors in general.

A Group member pointed out that the assets are almost always between the AMP and the point of connection that will be covered by the generic Metering Dispensation process, and so would not belong to the LDSO but instead would belong to the TSO. The member expressed the view that if loss compensation is being calculated for these, then logically it should be the TSO who performs the calculations as they own the equipment and they have the records of its technical specification. ELEXON noted this view and agreed that a mechanism may need to be developed in the future to achieve this.

The Group highlighted that the distance from the AMP to the DMP can range from tens of metres to hundreds of metres of overhead line or underground cable and questioned whether it would be useful to add in a specific threshold for Metering Dispensations. Some members of the Group suggested that over 50m could be a useful starting point figure i.e. you do not need to apply compensation to those under 50m. One Group member commented that they took some high level calculations which suggested that around 1,500m of 132kV cable between the AMP and point of connection does not have a material effect on losses and was not at a level within the accuracy of the metering itself (i.e. 0.5%). The member noted that this suggests that 50m may be shorter than what might intuitively have been expected. However, it was agreed overall for the 50m figure to be included in a potential CP as a starting figure and see what industry's views are.

Overall the Group agreed that as per the original proposal, a CP should be raised for a generic Metering Dispensation process with a standard methodology. They agreed that this would be the most appropriate solution for this exception, as quality assurance checks would be carried out which would generally improve the visibility of metering checks. It should be emphasised that there is no requirement to apply this change retrospectively to exiting circuits. Any changes arising from Issue 54 would apply only to Meters newly installed or upgraded after the relevant go-live date.

Location of DMP between Generating Plant and the TSO

The Issue Group discussed the second exception where the DMP between the TSO and Generating Plant is defined as "at the high voltage side of the generator and station transformers". A member of the Group noted that in these situations the points of connection are sometimes assumed and then compensated accordingly.

The Group agreed that there could potentially be unintended consequences if the DMP is amended as the original codification was carried out on the England and Wales market, with the introduction of the Pooling and Settlement Agreement (30 March 1990), which was not an organised market at the time. Members of the Group commented that the location of measurement transformers at the time (for example at Bulk Supply Points (BSPs)) was not at the newly created TSB and therefore the distances between the old and new measurement points was not negligible. It was also highlighted that wind farms were also not considered at this time.

The Group noted that Generators in England and Wales currently connected on high voltage (HV) sites, e.g. 400kV or 275kV, have a vested interest in keeping them maintained. The Group emphasised that there is a different solution in Scotland and that it should be recognised that there is a lot of legacy in Scotland which is not consistent with England and Wales. A member of the Group commented that moving the DMP in Scotland appears to introduce a question of discrimination between those generators and other generators as to who pays for the transformation losses. ELEXON agreed that it could be seen as a competitive advantage to Scottish generators (Meter at lower voltage side of the transformer connecting them to the Transmission System, and losses through transformers are accrued into transmission losses). However, ELEXON believes that both Ofgem and other industry codes may seek to define who provides what as part of a connection agreement and therefore where the point of connection is, and where the Settlement metering should go. It was agreed that background into the differentiation should be checked and any analysis carried out if necessary. The Group highlighted that any changes made would be prospective rather than retrospective.

Members of the Group commented that, ideally, they would prefer a commercial BP so that any consequences of changing the DMP going forward can be checked either through LAFs, fixed constants or through the Meter itself. They also noted that they would not want any compliance issues. ELEXON confirmed that a change to the DMPs would only relate to new connections going forward as Section L3.2.2 requires the Metering Equipment to comply with that version of the CoP which is applicable at the time of first registration of the resulting Metering System.

ScottishPower's Transmission substation query

A member of the Group highlighted that for ScottishPower Transmission substations, there is a requirement that states that *"the User shall provide a suitable cleared, levelled and drained site within 100m of the transmission 132kV collector substation's 33kV double busbar switchboard, and shall erect a stand-alone building outside the curtilage of the transmission substation, to contain the User's switchgear, metering and associated apparatus."* The Group agreed that if the policy meant that the User's Meters and the current and voltage transformers (CTs/VTs) needed to be located outside the substation away from the point of connection within the substation, then although this sounded inefficient, it acknowledged that this is a policy regulation.

The majority of the Group advised that it was unaware of a difference between ScottishPower Transmission and Scottish Hydro Electric Transmission requirements in this

area. The Group agreed that it needed to clarify with one of the Scottish transmission companies whether it was the Meters or CTs/VTs which had to be located within 100m of the substation and where the point of connection typically was. A member of the Group pointed out that this may be because of potential data or access issues but that this would need to be confirmed. The Group agreed that if this policy exists, and it means that CTs/VTs and the Meters must be located outside the substation away from the point of connection then going forwards it would potentially need a generic Metering Dispensation to cover that difference between the location of the CTs/VTs and the point of connection.

ELEXON has since confirmed with ScottishPower Transmission Ltd that the requirement to provide a building within 100m of the substation is for the User to house a separate circuit breaker (in its 'switchgear'), the Settlement Meters and communication lines. The Settlement CTs/VTs are provided by ScottishPower Transmission Ltd and are located within the substation itself, at its statutory circuit breaker for the circuit, which is the point of connection. The 100m rule applies to primary plant in order to minimise the extent of the User's network protected by ScottishPower Transmission Ltd's apparatus (the statutory breaker typically) and allows safe access for the User (or Meter Operator Agent (MOA)) to its switchgear and the Settlement Meters (which are typically within 25m). For demand customers and at GSPs, the Settlement CTs/VTs are also at the point of connection (outgoing side of the 33kV circuit breaker).

Location of DMP for Interconnectors

The Issue Group highlighted that there is no mention of the BritNed or East-West Interconnectors in the HH CoPs but noted that there is a very specific location of the DMP for two Interconnectors: the Sellindge substation for the Anglo French Interconnector and the Auchencrosh substation for the Moyle Interconnector.

The Group agreed that there were two possible options to address this issue:

- add in the new Interconnectors and define their DMPs specifically with reference to their individual circuits; or
- define the DMPs as "at the point(s) of connection to the TSO".

The Issue Group noted that the creation of a new Interconnector is not a common event but agreed that this issue should be future-proofed so that a change does not have to be made to the HH CoPs each time there is a new Interconnector. An Issue Group member highlighted that there may be a couple of new Interconnectors, e.g. to southern Ireland and Norway, in the foreseeable future and so resolving this issue now would prevent further changes having to be made in the future.

Overall, the Group agreed that the preferred route would be to create a generic definition for the Interconnector DMPs as "at the point(s) of connection to the TSO" to prevent the need for further changes to the HH CoPs to be made.

Metering Dispensation process – validation of compensation

Where the DMPs identified do not coincide with the actual point of connection, this can result in applications for Metering Dispensations being made by the Registrant to correct for losses to the point of connection. The Issue Group noted that there had been an increase in the number of Metering Dispensations being presented to the ISG and expressed concern that these should be exceptions rather than a standard process. The

Group noted the ISG's concerns about the lack of validation of compensation values for power transformer or line losses under the current Metering Dispensation process.

The Group commented that the ISG does not necessarily need to see the compensation values but would like someone with the relevant expertise to have seen them. It commented that currently the validation process is the responsibility of the Registrant, but noted that this normally falls to the MOA to calculate the compensation values. The Group questioned whether a standard approach should be taken so that the process is generic across industry. Members of the Group advised that judgement calls have to be made for some parts of the process and therefore questioned whether this can be standardised. A member of the Group did, however, identify that judgement calls are not normally materially significant and that power transformer/cable losses can be obtained regardless. Members of the Group also highlighted that some MOAs may see it as a commercial benefit to have the expertise to be able to calculate the compensation values and so standardising the process could be seen as a disadvantage for them.

A member of the Group suggested that, for validation purposes, the TAA could formally be involved in the Metering Dispensation application process. ELEXON advised that it would need to investigate whether any changes in the TAA contract would be required to be able to do so. Some members of the Group also suggested it may be useful to look at some form of methodology, principles or guidelines to accompany how to produce compensations. A member of the Group advised that guidance for compensation for vesting[8] had been produced in the past but that a new document may need to be made in an accessible format for the potential changes that will need to be made.

A member of the Group noted that there is a CVA MOA forum held annually each October and suggested that an ad-hoc meeting could be held to discuss the potential CP which proposes to amend the current process. Some members of the Group advised that not all MOAs would be familiar with calculating or applying compensations, and therefore guidance would be required. They agreed that the guidance could be distributed through the CVA MOA forum or offline to various experts to help ELEXON draw out the specifics. The Group noted that for assurance purposes, they would like compensation methodologies set up, checked and audited; however they acknowledged that this would not work for non-BSC agents.

Overall, the Group agreed that amending the process would make it more visible and highlighted the impact on Registrants' MOAs. The Group questioned whether using the TAA at the point of application in validating compensations may require a CP. ELEXON advised that theoretically no CP would be required as BSCP32 currently uses the term "Appropriate Parties" rather than setting out specific parties involved. The Issue Group agreed that the Metering Dispensation Review Group could include the TAA as an extra party in its guidance document to aid the Metering Dispensation process further.

ELEXON has since confirmed that based on the number of 2013/2014 applications, in which there were less than ten applications that would need to be validated by the TAA, it is envisaged that only a minor change would be required to the TAA contract. This would involve clarifying that the TAA validate any compensation values for power transformer losses or line or cable losses as part of the Metering Dispensation application process. This does not include validating any compensation values for measurement transformer errors as part of any application, including ones where no power transformer or line or cable loss compensation is required. ELEXON also identified that a minor cost may be associated with

[8] Splitting up of the Central Electricity Generating Board into separate private generating companies by handing over the assets.

this change but that this would be formally calculated as part of the impact assessment if a CP was raised to make this change to the TAA contract.

4 Conclusions

The Issue 54 Group agreed that changes are required to:

- change the DMP for a single LDSO connecting to the Transmission System to be "at the point of connection" and create a generic Metering Dispensation for where Metering Equipment cannot be located at the point of connection for practical reasons for the above, but within an agreed distance;
- change the DMP for Generating Plant connecting to the Transmission System to be "at the point of connection" to remove any ambiguity about where Metering Equipment needs to be installed; and
- create a generic definition for the Interconnector DMPs as "at the point(s) of connection to the TSO" to prevent the need for further changes to the HH CoPs; and
- create a standard methodology for any Metering Dispensation application where power transformer or line loss compensation is required (where the AMP is not at the DMP) and seek to involve the TAA in validating these during the Metering Dispensation application process.

The Issue 54 Group therefore agreed that CPs should be raised to progress the changes identified.

Appendix 1: Glossary & References

Glossary of defined terms

Acronyms and other defined terms used in this document are listed in the table below.

Glossary of Defined Terms	
Acronym	Definition
AMP	Actual Metering Point
BP	Boundary Point
BSC	Balancing and Settlement Code
BSCP	Balancing and Settlement Code Procedure
BSP	Bulk Supply Point
CoP	Code of Practice
CP	Change Proposal
CT	current transformer
CVA	Central Volume Allocation
DMP	Defined Metering Point
DSCP	Distribution System Connection Points
GSP	Grid Supply Point
HH	Half Hourly
HV	high voltage
ISG	Imbalance Settlement Group
LAF	Loss adjustment factor
LDSO	Licensed Distribution System Operator
LLF	Line Loss Factor
LV	low voltage
MDRG	Metering Dispensation Review Group
MOA	Meter Operator Agent
SCP	Systems Connection Point
SGT	Supergrid connected transformer
SVG	Supplier Volume Allocation Group
TAA	Technical Assurance Agent
TSB	Transmission System Boundary
TSO	Transmission System operator
VT	voltage transformer

Appendix 2: Issue Group Membership

Issue Group membership and attendance

Issue 54 Group Attendance		
Name	Organisation	13 Mar 14
David Kemp	ELEXON *(Chair)*	✓
Claire Anthony	ELEXON *(Lead Analyst)*	✓
Mike Smith	ELEXON *(Proposer)*	✓
Andrew Colley	SSE	✓
Lorna Short	RWE npower	✓
Colin Gentleman	SSE Metering Limited	✓
Guy Phillips	E.ON	✓
John Mills	National Grid	☎
Gary Henderson	IBM on behalf of ScottishPower	☎