semo
Single Electricity
Market Operator

2012
SEM Parameters for the Determination of Required Credit Cover

Document History

Version	Date	Author	Comment
1.0	31st August 2011	SEMO	Issued to Regulatory Authorities

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1 Introduction

1.1 Purpose

Under Section 6.174 of the Trading & Settlement Code (referred to as 'the Code'), the Market Operator (MO) is required to propose parameters used in the calculations of Required Credit Cover at least 4 months before the start of a Trading Year. This document provides the MO's proposals for these parameters for the Trading Year 2012.

1.2 Audience

The target audience for this document is Market Participants and the Regulatory Authorities.

1.3 Scope

This document provides proposals for the following parameters for the determination of Required Credit Cover for Trading Year 2012.

- Historical Assessment Period for Billing Period
- Historical Assessment Period for Capacity Period
- Analysis Percentile Parameter
- Credit Cover Adjustment Trigger
- Fixed Credit Requirement

1.4 Background

The Trading & Settlement Code sets out the rules for the calculation of Required Credit Cover for Participants. The calculation recognises that the Required Credit Cover for each Participant is made up of known and unknown exposures. The known exposure is based on invoiced amounts and published settlement values. The unknown exposure, called the Undefined Exposure (UDE), is based on statistical analysis of known historical settlement values in the case of Standard Participants. For New or Adjusted Participants the Required Credit Cover is calculated using forecast volumes as historical settlement values are not available or are not reflective of current levels of settlement.

In each of these calculations, and in the day to day credit risk assessment process, a number of parameters are used. These parameters are as follows:

- *Historical Assessment Period for Billing Period (HAPB)* – this sets the number of historical days over which the analysis of Trading Payments and Trading Charges will be carried out for credit purposes.
- *Historical Assessment Period for Capacity Period (HAPC)* – this sets the number of historical days over which the analysis of Capacity Payments and Capacity Charges will be carried out for credit purposes.
- *Analysis Percentile Parameter* – this sets the percentile confidence value in the statistical analysis used for New, Adjusted and Standard Participants.
- *Credit Cover Adjustment Trigger* –a Participant will be classed as an Adjusted Participant under the Code if the Participant's trade volumes increase or decrease by a percentage greater than this value.
- *Fixed Credit Requirement* – this sets the value of Required Credit Cover that must be in place for each registered Supplier Unit or Generator Unit in the Single Electricity Market (SEM) in order to meet resettlement charges that may arise up to 13 months after the initial settlement.

Although these parameters are considered variable, under the Code, they will be set from year to year.

In light of approved Mod 54_08 and related changes to sections 6.174 and 6.181 of the Trading and Settlement Code, SEM-O will not be reporting on Maximum Level of the Warning Limit anymore. The default limit of 75%, as set in section 6.181, will be maintained until a revision or a change to the Code is required.

2 Recommendations

Based on the analysis performed the credit parameters shown in Table 1 are proposed by the MO for use in Trading Year 2012. These proposed values are considered the best combination to ensure appropriate levels of Credit Cover in SEM.

Credit Cover Parameter	2011 Approved Value	2012 Proposed Value	
Historical Assessment Period for Billing Period	100 days	100 days	
Historical Assessment Period for Capacity Period	90 days	90 days	
Analysis Percentile Parameter	1.96	1.96	
Credit Cover Adjustment Trigger	30%	30%	
Fixed Credit Requirement for Supplier Units based on rate of 8.77€/MWh of average daily demand subject to a minimum value of €1,000 and a maximum of €15,000 [1]	€10,000	**Min. of €1,000 with max. of €15,000**	[2]
Fixed Credit Requirement for all Generator Units	€5,000	€5,000	
Fixed Credit Requirement for Netting Generator Units	€5,000	**€1,000**	[2]

Table 1 - Proposed 2012 Credit Cover Parameters

As noted by the Regulatory Authorities approval of Modification 26_08 "Definition of Adjusted Participant", and made clear in the consultation on Suspension Delay Periods (26/07/2008), the market is not and cannot be fully collateralised. The parameters provided above attempt to provide a balance between maintaining a low level of risk of bad debt in the SEM while not over burdening Participants with credit cover requirements which could be seen as a barrier to entry or a barrier to continuation of trade.

1 Average Daily Demand will be calculated for Standard Participant based on their historical demand and for New or Adjusted participants on their projected forecast demand

2 Following direction by CER in 2010 to review FCCR based on Unit size

3 Analysis of Credit Risk Parameters

The following section provides the context, analysis, conclusions and recommended values for each of the credit cover parameters proposed by the MO for Trading Year 2012.

In the modelling and analysis the focus was on UDE period as this, along with resettlement, forms the only unknown exposure within SEM. The known exposure of invoiced and settled not invoiced amounts is exactly known and included in the credit cover requirements of a Participant as a matter of course. It should be noted that with the introduction of Intra Day Trading (IDT) in July 2012, how Credit Risk is calculated and applied to Participants will change. How the process of Credit Parameters will be analysed may have to change.

Throughout this document references will be made to the 'UDE Variance'. This is not a Code term, but is a comparison value defined as the percentage difference between the calculated UDE (as defined in the Code credit cover calculations) and the realised UDE. The realised UDE being the actual exposure that the Participant had for the UDE period (calculated retrospectively once settlement values are available).

The important aspects of the UDE Variance comparison value are:

- Where the UDE Variance percentage is > 0%, the calculated UDE is greater than the realised UDE and the calculation of Credit Cover for the Participant would have been over estimated.
- Where the UDE Variance percentage < 0%, the calculated UDE is less than the realised UDE and the calculations of Credit Cover for the Participant would have been under estimated.

3.1 Historical Assessment Period for Billing Period

3.1.1 Context

The Code sets out two methods of calculation of the UDE for Participants. The Standard Participant method uses statistical analysis of settlement values for Trading Payments and Charges, and Variable Market Operator Charges. The second method used for New or Adjusted Participants uses statistical analysis of historical System Marginal Prices (SMP) in the Market combined with forecast volumes provided by the Participants. Again, IDT will likely require a change in this methodology.

In both of these methods, the analysis is conducted over a period of time known as the Historical Assessment Period for Billing Period (HAPB). This is a period of recent history of the Participant in the SEM. The UDE for the Billing Period refers to the UDE generated in the Energy Market.

The duration of the HAPB accounts for typically 35% of the total exposure of a Participant and will have a significant impact on how accurately the calculated Credit Cover mirrors the realised Credit Cover Requirement.

3.1.2 Analysis

The analysis for the HAPB was based on actual settlement volumes for a sample of typical SEM Participants from the November 2007 market start through to the end of July 2011.

A key dependency on the duration of the HAPB, and also the HAPC, is the Supplier Suspension Delay Period. This is the time allocated, before a Suspension Order becomes effective, to allow the Meter Data Provider and the Market Operator, to transfer the affected demand customers to other existing Suppliers or to the Supplier of Last Resort. It is assumed that the current value of 14 calendar days will not change during 2012. It is recommended that should the Supplier Suspension Delay Period be amended, a review of the credit parameters is completed as this will impact on the Undefined Exposure of the Participant. The current analysis is based on a Typical Undefined Exposure of 16 days, which include 14 days of Suspension Delay Period plus two days of typical of the unsettled period at the time of Required Credit Cover Calculation.

The approach taken in modelling the HAPB was to identify a sample of Participants that were representative of the types of settlement profiles seen in the SEM, and perform the modelling and analysis on these representative samples.

Initial analysis provided the following four typical demand/generation profiles in the SEM.

- Supplier with steady demand *(SU - Steady)*
- Supplier with seasonal demand *(SU – Seasonal)*
- Wind Generator with variable generation *(GU – Wind)*
- Thermal Plant with planned outages *(GU – Outage)*

Normalised volumes (Daily Volume/Average Daily Volume) for these four typical profiles are shown in Figure 1, 2 and 3 below.

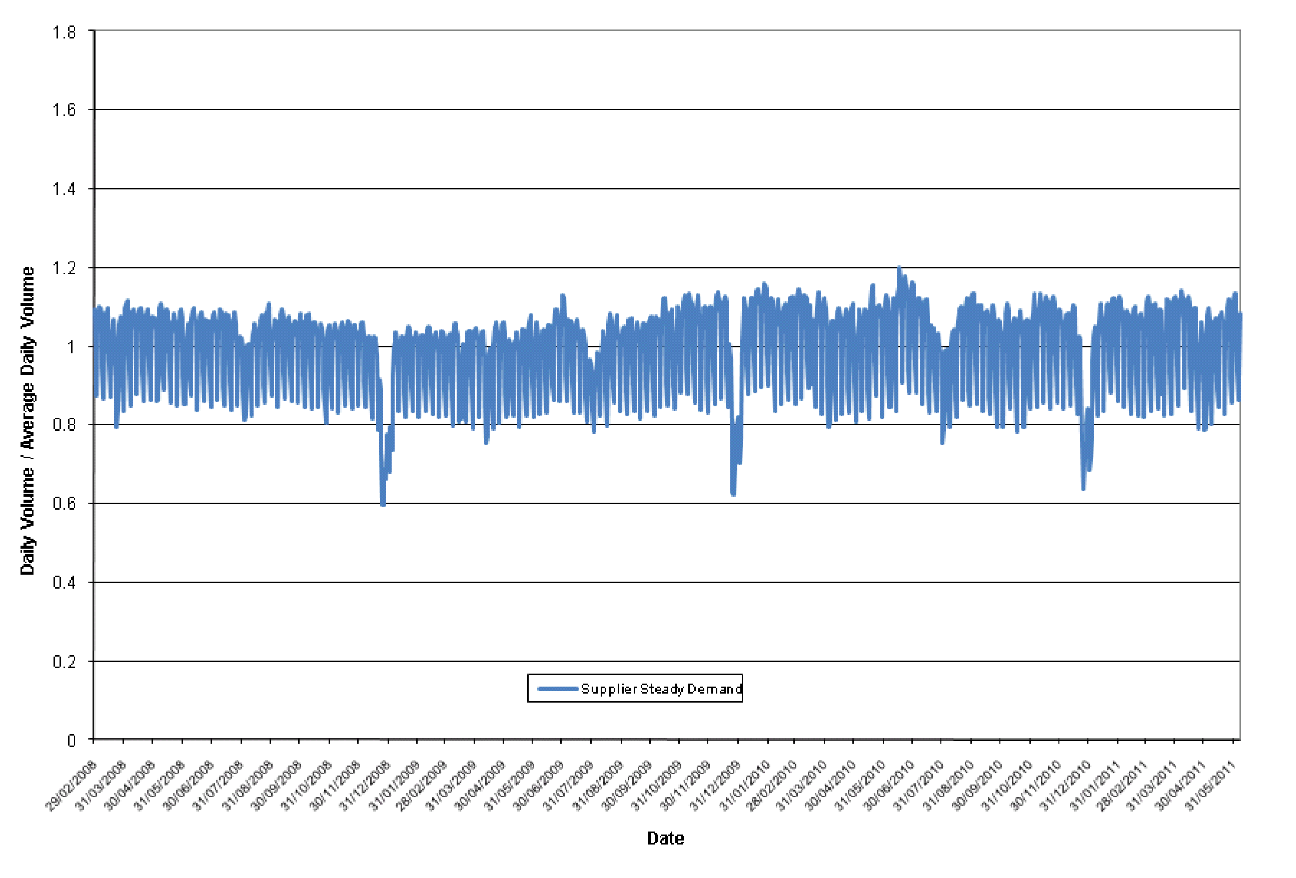

Figure 1 - Normalised Typical Supplier with Steady Demand Profile

Figure 1 shows the demand profile for a typical Supplier with steady demand. Although there are fluctuations in the demand profile, these are cyclical (usually weekly and also during the Christmas period) and over a longer time horizon, the general trend is for a constant demand. This profile is the most common in the SEM for Suppliers.

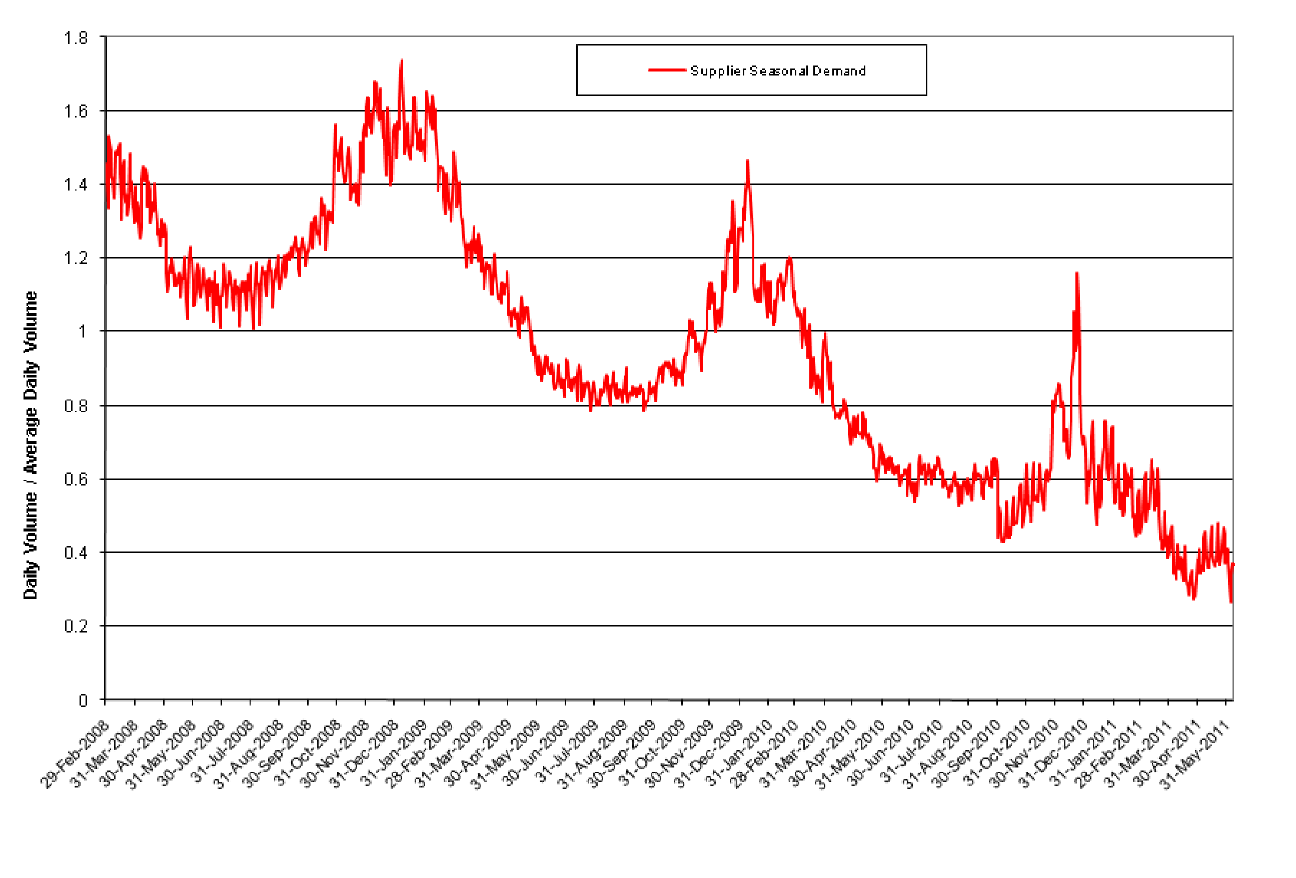

Figure 2 - Normalised Typical Supplier with Seasonal Demand Profile

Figure 2 shows typical demand profiles for a Supplier with seasonal demand. Over a longer time horizon the general trend is a cyclical fluctuation in demand with a decrease in total demand each year in line with the recent economic conditions. A peak over winter 2010-11 was noted due to adverse weather experienced at that time.

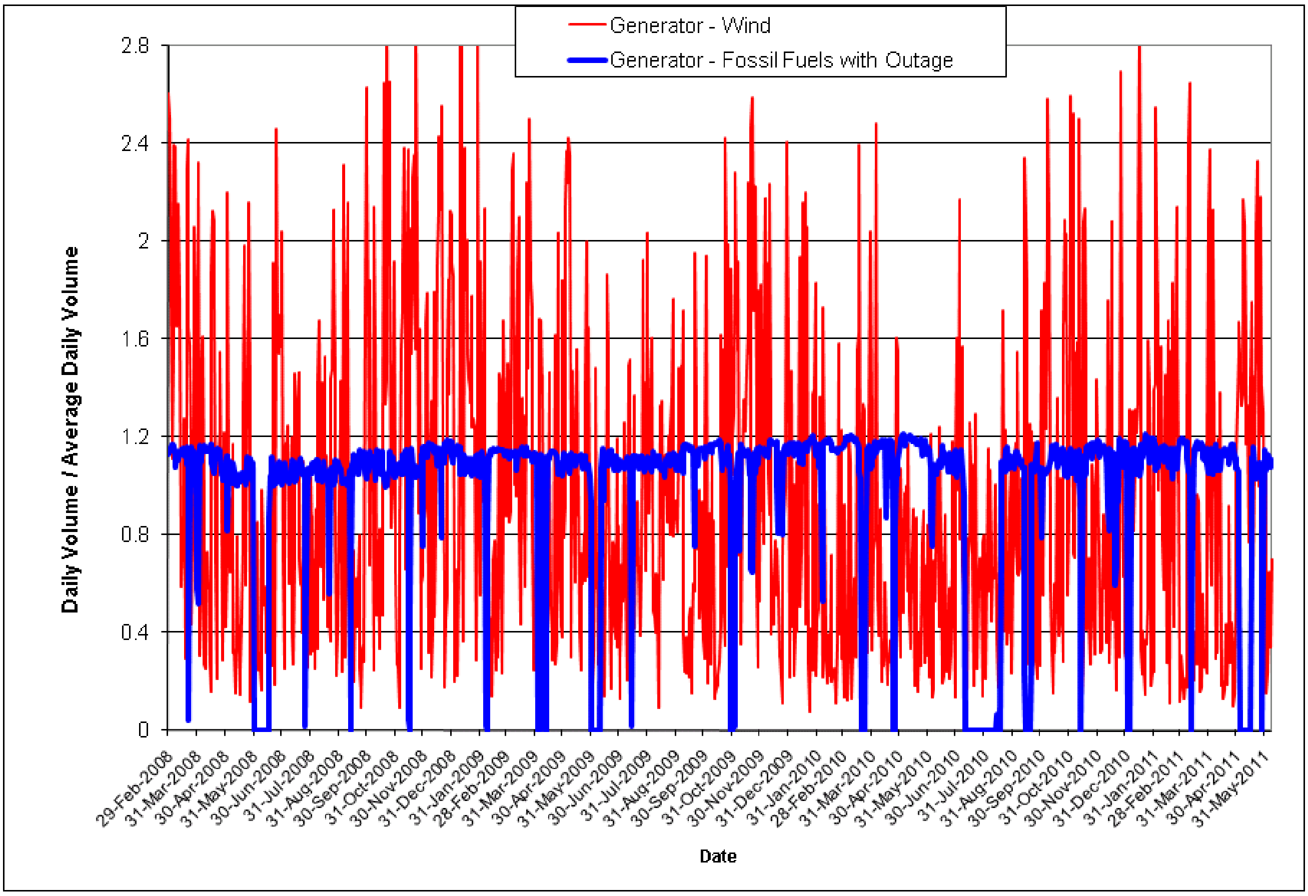

Figure 3 - Normalised Typical Wind and Thermal Plant Generation Profiles

Figure 3 shows typical generation profiles for wind and thermal plant. As would be expected the wind generator profile is variable as it is reliant on climatic conditions. The thermal plant has a predictable regular profile which is interrupted by periods of plant outage (e.g. July 2010 in the above example).

Each of these four typical demand/generation profiles was used in modelling to determine the UDE Variance (as defined in Section 3.0 of this document).

The outcome of the modelling for the Supplier with steady demand and a HAPB of 100 days is shown in Figure 4.

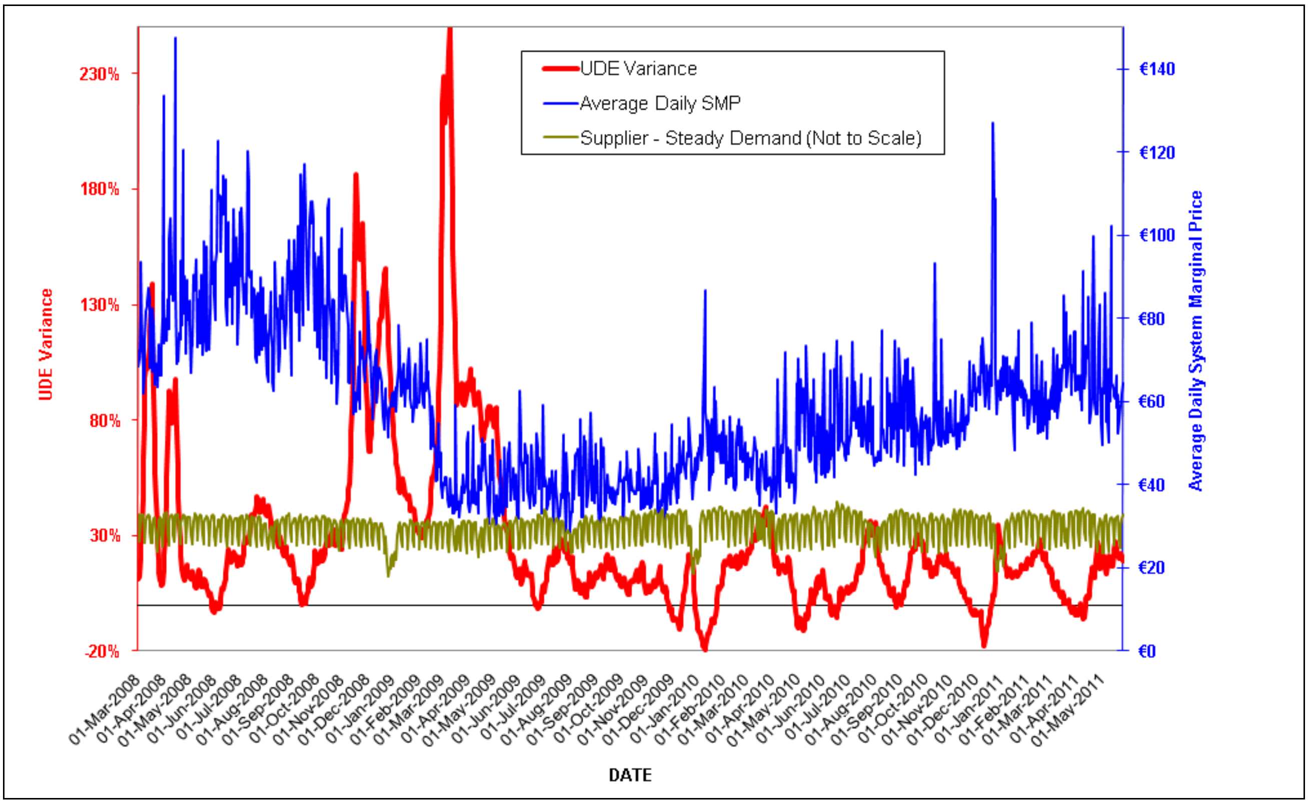

Figure 4 – Effect of Price and Demand on UDE Variance

Figure 4 illustrates that the SMP, in this case represented as an average daily SMP, has a significant influence on whether the calculated UDE is under or over estimated. Where the calculated UDE is greater than the realised UDE (i.e. the UDE Variance is greater than 0%), the Participant will have excess Credit Cover in the SEM. Where the calculated UDE is less than the realised UDE (i.e. the UDE Variance is less than 0%), the Participant will have under estimated Credit Cover in the SEM.

There is a strong correlation in Figure 4 between under-estimation and significant increases in the average daily SMP in the SEM. This is illustrated in the periods around January, May-July and December 2010. This is further emphasised by the fact that during these same periods of under-estimation the demand profile of the Supply Participant remains steady indicating demand is not a contributing factor.

As noted by the Regulatory Authorities approval of mod 26_08 and made clear in the consultation on Suspension Delay Periods (26/07/2008), the Market is not and cannot be fully collateralised. These increased average daily SMP events are one of the main reasons that the concept of full collateralisation of the SEM is not possible.

Variances in the UDE during the 2008 to mid-2009 period have been explained in previous Credit Parameter recommendation reports. For the period Nov 2009 to July 2010, the SMP is stable at approximately €60perMWhr. This in turn led to less UDE variance. The largest under-estimation occurred in January & December 2010 and January 2011 which coincided with periods of high variability in SMP and Demand and aligns with the cold snap.

From a risk mitigation perspective it is crucial to ensure the Credit Cover calculations of Suppliers for UDE are as accurate as possible, without representing a burden for Participants. This is due to the fact that Suppliers typically owe money to the SEM as a result of initial settlement and typically have a positive Credit Cover requirement. Generators on the other hand are more likely to be owed money by the SEM as a result of initial settlement and typically have a negative Credit Cover requirement. Typically Generators in SEM need to provide only the Fixed Credit Requirement which covers resettlement.

Based on this higher Supplier risk, the analysis below concentrates on the two Supplier demand profiles identified earlier, namely:

- steady demand
- seasonal demand

Figure 5 below illustrates how the UDE Variance changes with different HAPB values. Each of the profiles is for the same Participant (Supplier – steady demand) over the same period with different HAPB being the only variable.

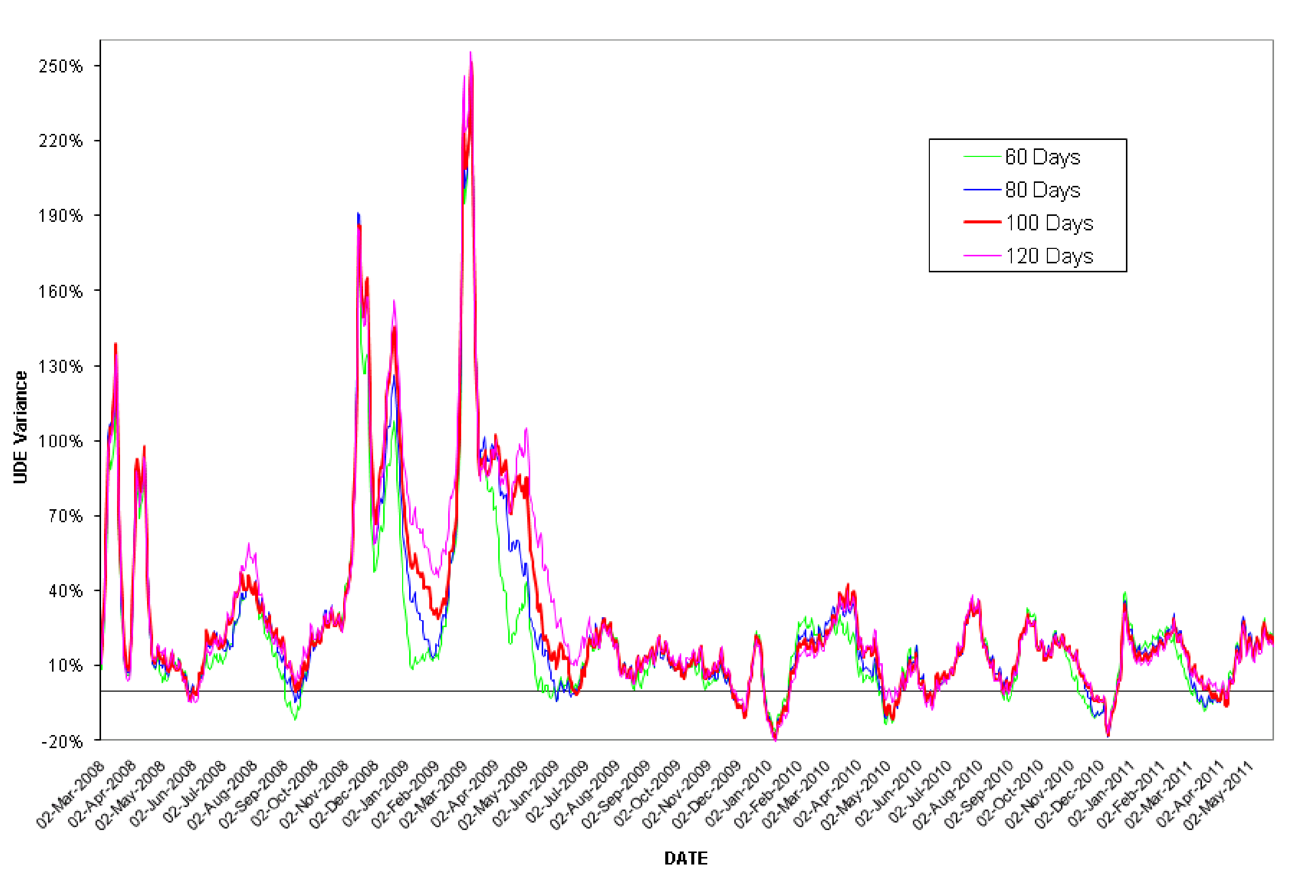

Figure 5 – Effect of Different HAPB on UDE Variance for Supplier with Steady Demand

Figure 5 illustrates that the smaller the HAPB the higher the number of events and the magnitude of under-estimation (i.e. graph lines dropping below 0%). It also shows that a larger HAPB would react more slowly to sudden changes in SMP. As occurs in the periods between January and February 2009, and April to June 2009, where larger HAPB values result in a larger over-estimation for a longer period.

HAPB of 100 days appears to continue to provide the best compromise solution. This HAPB has very few days where credit cover is under-estimated (as opposed to HAPB of 60, 80 and 90 days which have a higher proportion of days under-estimated) while avoiding excessive over-estimated (as occurs for the HAPB 120 days).

Figure 6 below shows how the UDE Variance varies for a HAPB of 100 days with different demand profiles. The seasonal demand tends to accentuate the peaks and troughs of the UDE Variance. This characteristic is true for all HAPB values analysed.

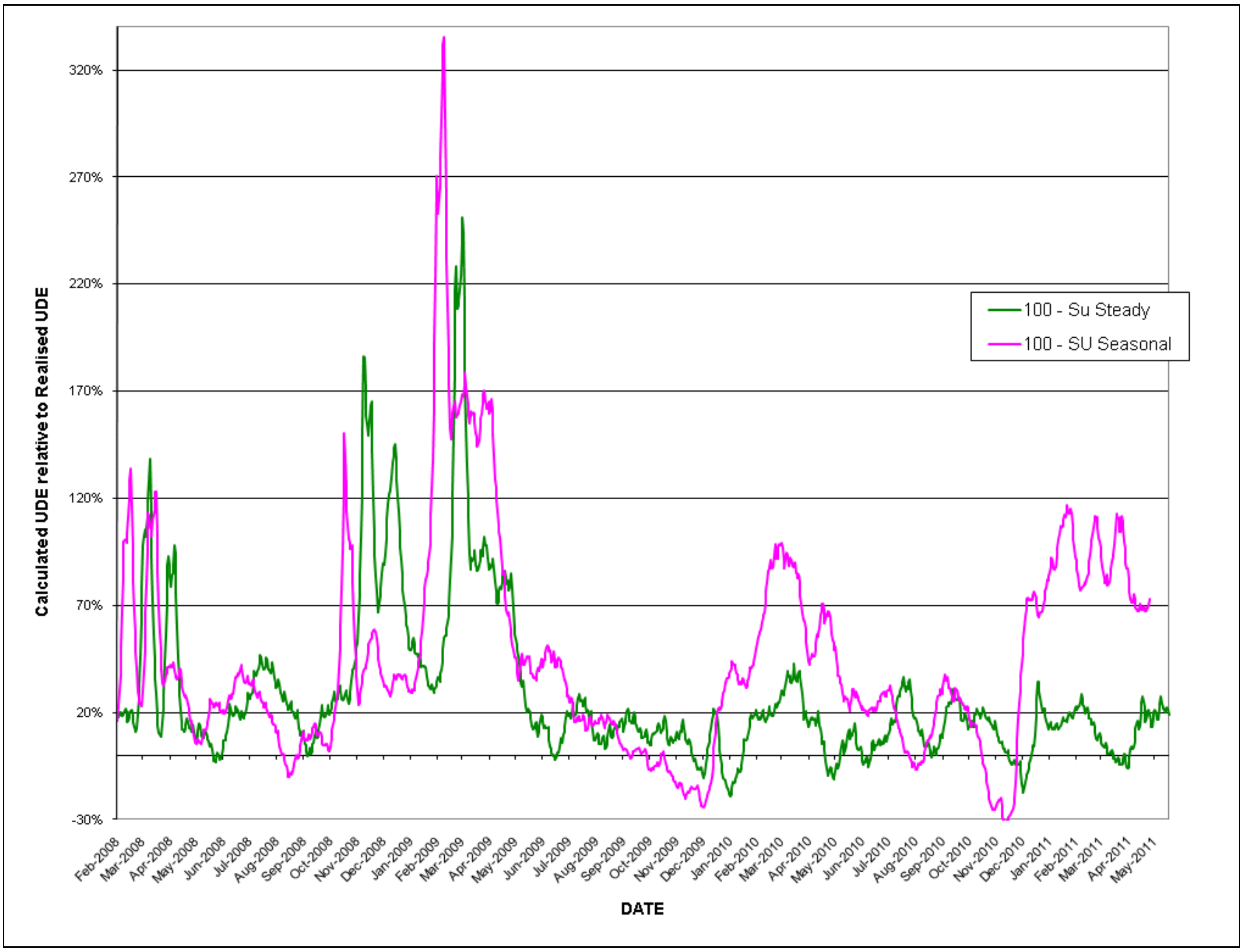

Figure 6 – UDE with Varying Demand Profiles for same HAPB

As mentioned previously, the focus of the analysis has been on the Supplier demand profiles as these Participants pose the most risk to the SEM should they default in particular on initial settlement. With regard to the Generator profiles for wind and thermal plant, the statistical calculations of Credit Cover do not provide as good a fit as for Suppliers. In the case of wind this is due to the variability of generation. In the case of thermal plant, outages of more than a few days can have a significant impact on Credit Cover calculations.

3.1.3 Conclusions

Although there is no obvious solution to improve Credit Cover calculations for wind generation which is very difficult to predict with any accuracy, for Generators with planned outages the introduction of modification 26_08 as outlined in Section 3.4 now provides an obligation for Generators to inform the MO of changes in forecast generation that should lead to the Participant becoming Adjusted. Credit calculations would then be based on forecast generation rather than historical settlement data. This should help reduce significant deviations of Generator calculated UDE from the realised UDE.

From a risk mitigation perspective it is important to ensure Suppliers UDE, and therefore total credit risk exposure, is calculated in a way that reduces the number of occurrences where UDE is under-estimated.

The SMP in the SEM, and particularly increased price events, has the largest impact on whether the calculated UDE adequately models the realised UDE. Variance in Supplier demand has a lesser effect on Credit Cover UDE calculation adequacy.

Different HAPB values lead to quite different UDE Variance profiles. Using a larger HAPB tends to smooth changes in the UDE variance, and tends to reduce the number of days Participant Credit Cover is under-estimated. However increasing the HAPB any further than the current level would increase the amount of excess Credit Cover on most days, with a very limited decrease in the number of under-estimation events.

3.1.4 Recommendation

Based on the analysis, the current HAPB of 100 days is recommended for 2012 as it provides a good compromise allowing risk mitigation without being excessively onerous on Suppliers in terms of over-estimation of credit cover requirement.

3.2 Historical Assessment Period for Capacity

3.2.1 Context

The HAPB, outlined in section 3.1 relates to the SEM Energy Market. In addition to this the Code also uses a Historical Assessment Period for Capacity Period (HAPC) as part of the UDE calculations for the Capacity Market.

3.2.2 Analysis

Similar data sets, modelling and assumptions were used for the HAPC as were used for the HAPB. Refer to section 3.1 for further details.

The outcome of this modelling for the Supplier with steady demand is shown in Figure 7 below.

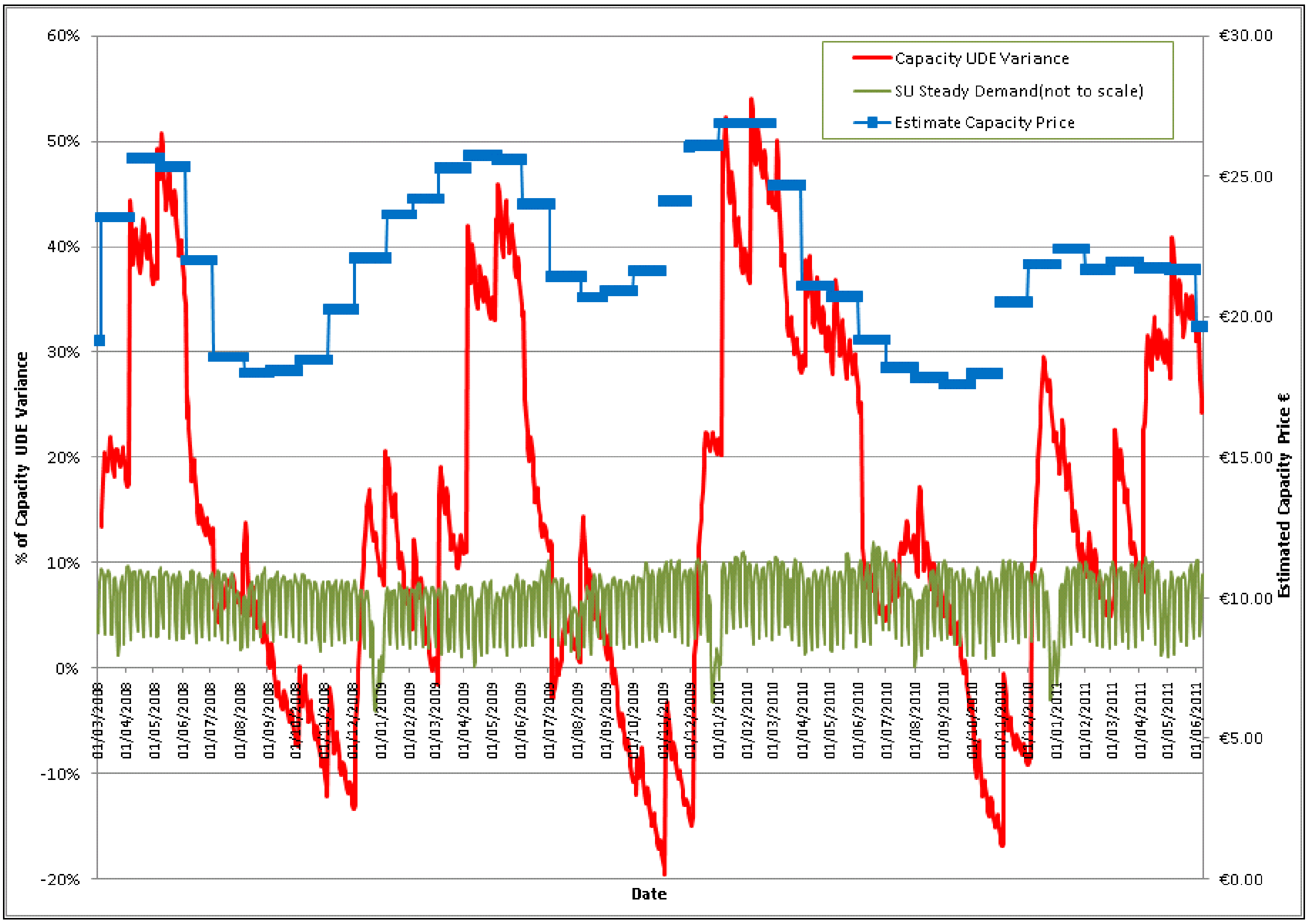

Figure 7 – Effect of Price on Capacity Calculated Undefined Exposure

Figure 7 illustrates that the Capacity UDE Variance is greatly influenced by the Estimated Capacity Price (ECP) in the SEM. The step changes in the UDE Variance can be attributed to availability of ECP information. The ECP values are only available on a monthly basis after the indicative Capacity settlement is completed. The general trend is when the ECP increases the step change in Capacity UDE Variance is upward. Where the ECP drops the Capacity UDE Variance is downward.

In the example above the Supplier has steady demand. Therefore, the change in Capacity UDE Variance can be attributed to the change in the ECP.

As described in the HAPB analysis, from a risk mitigation perspective it is crucial to ensure the Credit Cover calculations of Suppliers for UDE are as accurate as possible. This is due to Suppliers being more likely to owe money to the SEM from initial settlements and typically having a positive Credit Cover requirement. Generators on the other hand are more likely to be owed money by the SEM from initial settlement and tend to have a negative Credit Cover requirement. Typically Generators in SEM need to provide only the Fixed Credit Requirement.

Based on this higher Supplier risk, the analysis below concentrates on the two Supplier demand profiles identified earlier, namely:

- steady demand
- seasonal demand

As for the HAPB, Figure 8 illustrates how the UDE Variance varies with different HAPC values. Each of the profiles is for the same Participant (Supplier – steady demand) over the same period with different HAPC being the only variable. Where the percentage is greater than zero the Participant is over-estimated and where the percentage is less than zero the Participant is under-estimated.

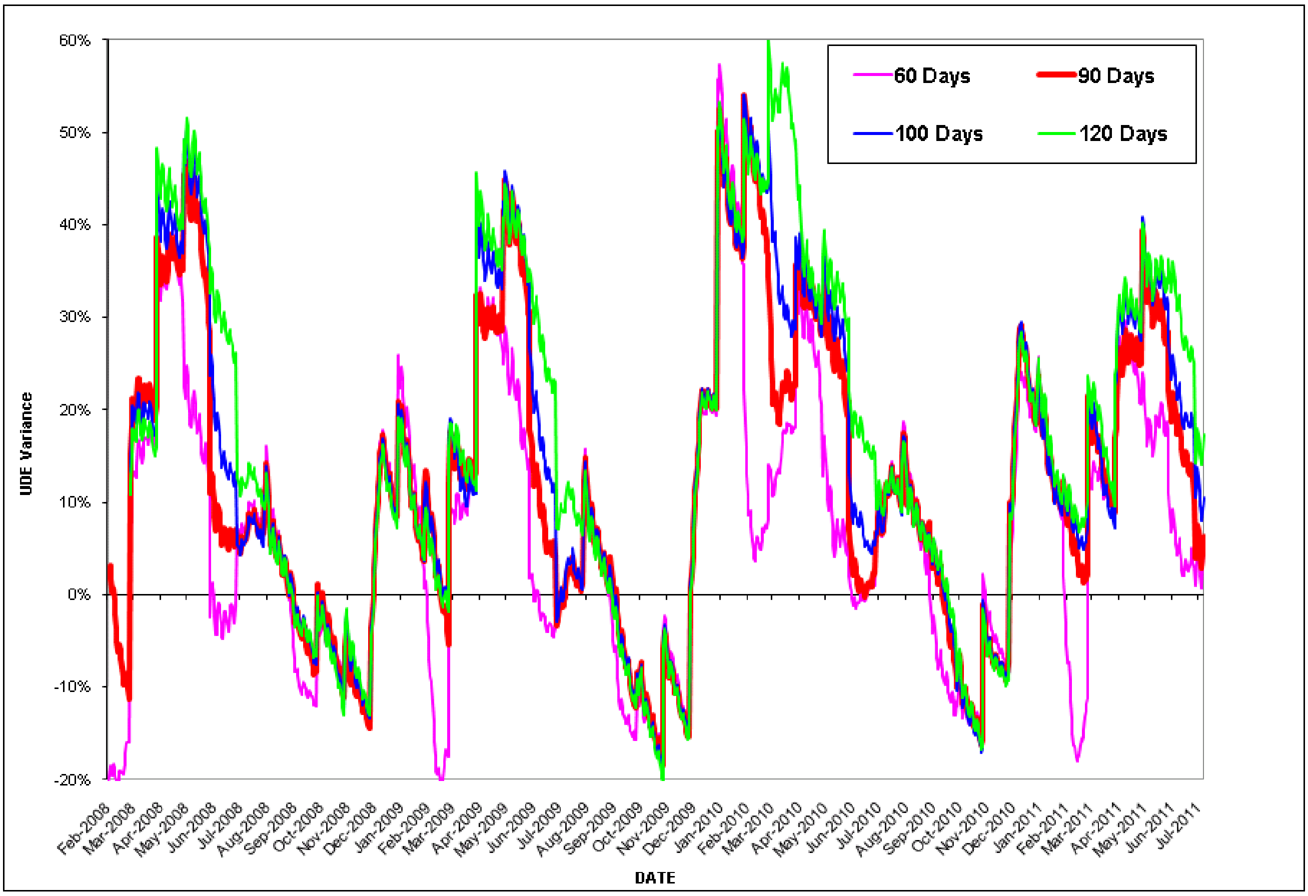

Figure 8 – Capacity Market - UDE Variance with Different HAPC

Based on Figure 8 the use of a HAPC of 90 days continues to be a good compromise between reducing the occurrences of under-estimation and reducing excessive over-estimation. It also has practical advantages when Participants becomes an 'Adjusted Participant', due to a step change in their demand/generation, and they need to provide forecast data for the longer of the two HAPB or HAPC. Keeping the HAPC and HAPB aligned appears to be a sensible course of action to avoid a situation where Participant Credit Cover is calculated for an extended period using forecast data due to the HAPC being longer than the HAPB. The change from forecast to historical data for Capacity can only occur in approximately 30 day increments as settlement of amounts occurs. This means that, with any HAPC greater than 90 days the actual elapsed time of approximately 120 days must occur before a Participant can become standard and use historical data. Using a HAPC of 90 will mean that Participants would not be exposed to an additional 20 days before switching to historical data which should provide a more accurate calculation of UDE.

Figure 8 shows that the profile for 90 days generally provides a lower level of over-estimation than the 100 or 120 day HAPC and a similar trend for under-estimation.

3.2.3 Conclusions

From a risk mitigation perspective it is important to ensure Suppliers UDE, and therefore total credit risk exposure, is determined in a way that reduces the number of occurrences where calculated exposure is less than realised exposure.

The prices set in the SEM have the largest impact on whether the Capacity calculated UDE adequately models the realised UDE. Variance in Supplier demand has a lesser effect on Credit Cover UDE calculation adequacy. Different HAPC values lead to varying UDE Variance.

The HAPB generally has a greater effect on how accurately the total calculated UDE matches the total realised UDE. It accounts for between 50-75% of the UDE.

Using a HAPC of 90 days aligns well with the proposed HAPB of 100 days and will provide an adequate level of Capacity UDE calculation while allowing for the practicalities of market operation.

3.2.4 Recommendation

The MO would recommend the HAPC for 2012 be maintained at 90 days.

3.3 Analysis Percentile

3.3.1 Context

The statistical calculation of UDE for Standard Participants is based on the choice of a percentile value. As part of this calculation the standard deviation of the samples is multiplied by the Analysis Percentile Parameter and then added to the mean UDE in order to arrive at the UDE Credit Cover Requirement. Depending on the Analysis Percentile used, the resulting value can be said to be approximately the 90^{th}, 95^{th} or 98^{th} percentile.

Analysis Percentile	Analysis Percentile Parameter
90	1.645
95	1.96
98	2.33

Table 2 – Analysis Percentile Parameters

3.3.2 Analysis

The modelling was performed on the typical demand/generation profiles described previously in Section 3.

Taking the Supplier with steady demand as an example, Figure 9 below illustrates two key points.

- As the Analysis Percentile Parameter increases the UDE Variance tends to shift upward slightly Participants Credit Cover becomes less frequently under-estimated.
- With a HAPB held constant at 100 days, as used in Figure 9, the Analysis Percentile Parameter has very little impact on the UDE Variance. Particularly between the 1.96 and 2.33 Analysis Percentile values. These appear almost as one line in Figure 9 below.

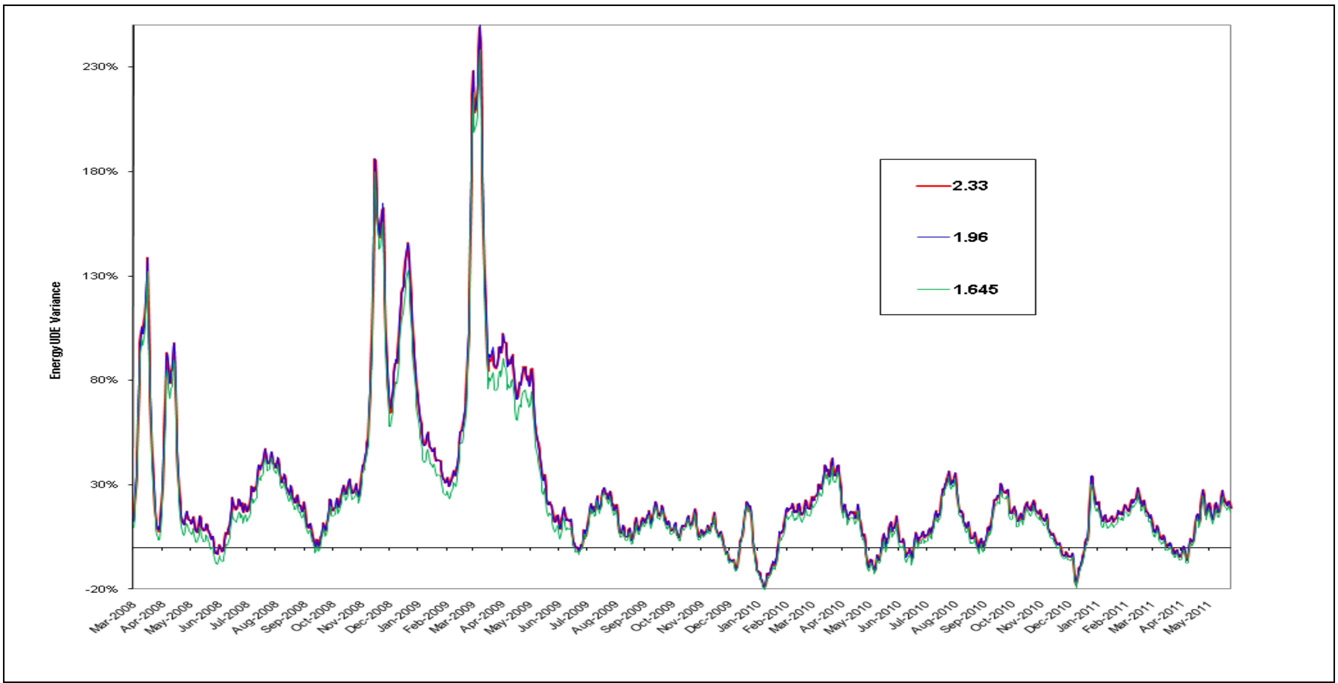

Figure 9 – Different Analysis Percentiles Effect on UDE Variance with HAPB of 100 days

The same trend is evident for the other demand/generation profiles used in this study and for Capacity.

Figure 10 below illustrates that in Capacity, just like in Energy, with a HAPC at the current level of 90 days, the Analysis Percentile Parameter has very little impact on the UDE Variance

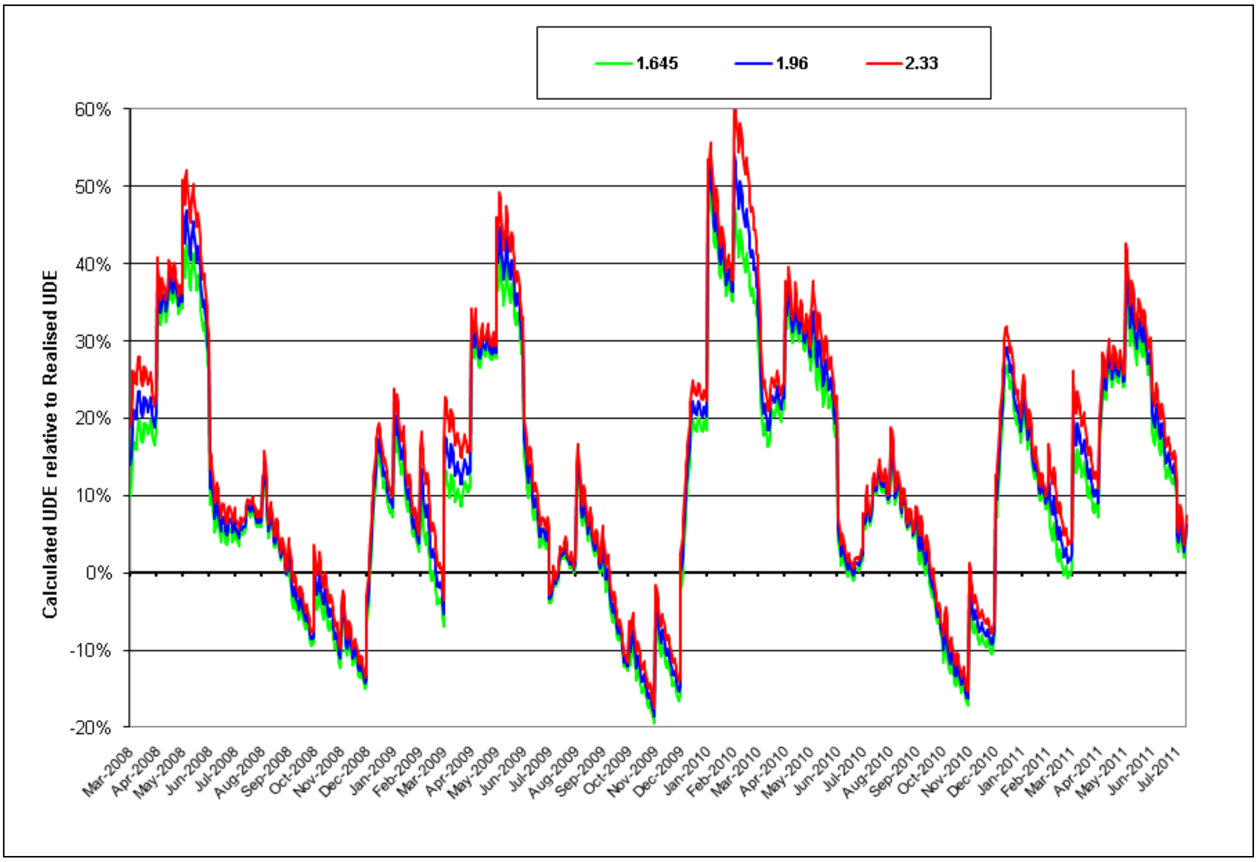

Figure 10 – Different Analysis Percentiles Effect on UDE Variance with HAPC of 90 days

3.3.3 Conclusions

Generally, as the Analysis Percentile Parameter increases, the number of occurrences of under-estimation is reduced. However, this also increases the percentage of time that Participants are over-estimated.

The Historical Assessment Period has a more significant effect on the UDE Variance than the Analysis Percentile Parameter used in the Credit Cover calculations.

3.3.4 Recommendation

Given the proposal to use the 100 days for the HAPB and 90 days for HAPC, and that Analysis Percentile Parameter provides minimal change in the UDE Variance, the MO would recommend that the current value of 1.96 is maintained for 2011.

3.4 Credit Cover Adjustment Trigger

3.4.1 Context

The statistical calculations for Standard Participants, as set out in the Code, assume a normal distribution and, as such, work to a reasonable effectiveness when Participant volumes of trade are not subject to major fluctuations. However, this assumption is not maintained under certain market conditions.

The statistical calculations are intended to accommodate small changes in Participants demand/generation profiles. However, where a step change in the demand/generation profile occurs the statistical basis will not be effective. This may be even more evident following the introduction of IDT.

In accordance with Section 6.182 of the Code (which includes modification 26_08 from 22nd July 2008), a Participant is required to notify the MO if they reasonably expect that a step change in their demand/generation profile will occur. The trigger for a step change is when the change is expected to be greater than the Credit Cover Adjustment Trigger. The Participant would then be classed as an Adjusted Participant and forecast volumes provided by the Participant would then be used for Credit Cover calculations rather than the statistical calculations based on historical settlement data.

A step change in the demand/generation profile of a Participant may be caused by a number of events including but not limited to:

- acquisition of new assets
- winning significant new customers in the retail market
- significant Generator planned outage
- taking advantage of additional capacity on the Interconnector

The Code definition for when a Participant should be considered Adjusted is:

- The Participant reasonably expects that, compared with the time-weighed average of metered quantities across all of the four most recent Billing Periods, the forecasted averaged metered quantities with respect to its Units will increase or decrease by more in absolute terms than the Credit Cover Adjustment Trigger.

3.4.2 Analysis

The analysis was performed on all Participants effective for the whole of the study period from June 2010 to June 2011. This provided a total of 62 Participants used in the Credit Cover Adjustment Trigger analysis. 22 of the Participants were Suppliers, 38 were Generators and 2 were Interconnector Users. This analysis period includes all seasonal changes in demand and outage periods.

It was also assumed that Participants had perfect foresight, meaning that their forecast volumes for the next four billing periods were identical to the actual volumes metered.

Where a step change occurs in the demand/generation profile of a Participant, this will have an effect on the Credit Cover calculations until either the Participant informs the MO and they become an Adjusted Participant or, if they do not become an Adjusted Participant, it will effect the Credit Cover calculations until sufficient time have passed that the step change event is outside the HAPB.

Table 3 below provides details of the number of Participants that, assuming perfect foresight, should have been classed as an Adjusted Participant at least once in the year analysed. The table shows these numbers change with the use of different Adjustment Trigger values.

The results have been grouped based on the Participant type (Supplier, Generator, Interconnector) and the apparent reason for the step change in volumes.

Participant Type	Apparent Reason for Adjustment	Adjustment Trigger							
		5%	***10%***	***15%***	***20%***	***30%***	***40%***	***50%***	***60%***
Suppliers	Very Low Demand(<2MW per day)	4	4	4	4	**4**	4	4	4
Suppliers	Change in Demand	18	16	12	9	**9**	8	7	7
Generators	Outage related	11	11	11	11	**11**	10	10	10
Generators	Wind	27	27	27	27	**27**	27	27	27
Interconnectors	Change in Trading Pattern	2	2	2	2	**2**	2	2	2
Total		62	60	56	53	**53**	51	50	50

Table 3 - Adjustment Trigger Level Comparisons by Unit Type and Apparent Adjustment Reason

The results trend is similar to that found in the 2011 Credit Parameters and the same rationale still applies.

From Table 3 it can be seen that almost all Supplier Units with very low demand (i.e. on average<2MW per day)and all Wind Generators, would have been required to declare themselves as Adjusted at least once during the analysis year independent of the Adjustment Trigger used. This indicates that these types of Unit have large variations in relative demand/generation. As wind generation and low demand Supplier Units are unlikely to be able to predict future demand/generation accurately, they are unlikely to declare themselves as Adjusted. Instead the statistical calculations must be relied upon in this instance. Therefore the setting of the Adjustment Trigger based on these types of Units is less relevant. The same is also true with regard to Interconnector Units.

For all remaining standard Suppliers and Generators, a compromise needs to be reached between catching large step changes for Suppliers and taking into account outages of Generators. An Adjustment Trigger at 30% still appears to strike the right balance. Although identical results were obtained by using a value of 20%, the MO believes that this would not be as easily predictable for all Participants and therefore a value of 30% is still recommended for 2012.

When considering the appropriate Adjustment Trigger value it is important to note that where a step change occurs, the actual effect on the Credit Cover Calculations is not 1 for 1. UDE accounts for typically 44-67% of the total Participant exposure. If a Participant's demand is out by 15% the Credit Cover will be out by between 6-10%. Given the statistical calculations use a 95th percentile value for UDE a step change has even less likelihood of the Participant having insufficient Credit Cover to meet a default event.

3.4.3 Conclusion

Different types of Units will have varying demand/generation profiles. Some of these Unit types will have significant difficulty in predicting forecast demand/generation in order to identify if they should declare themselves as Adjusted, namely, wind and low demand Supplier Units.

The Adjustment Trigger used in the SEM needs to be a compromise of ensuring the Credit Cover calculations are based on representative demand/generation, balanced with triggering Participants to be Adjusted for changes in demand/generation that are not step changes but only minor changes in demand/generation profile.

3.4.4 Recommendation

The MO would recommend the Adjustment Trigger be maintained at 30% for 2012 as this would cover the majority of step change events that are foreseeable for both Supplier and Generator Participants

3.5 Fixed Credit Cover Requirement

3.5.1 Context

The Trading & Settlement Code provides for a Fixed Credit Cover Requirement (FCCR). This is an amount set separately for Generator Units and Supplier Units.

The intention of the FCCR is to provide a sufficient level of Credit Cover for Participant liabilities resulting from resettlement of the market 4 months (M+4) and 13 months (M+13) after Initial Settlement.

3.5.2 Analysis

Resettlement amounts published between June 2010 and July 2011, which included Energy and Capacity M+4 from Feb 2010 to March 2011 and Energy and Capacity M+13 from May 2009 to June 2010, were used in this analysis.

Only Units that were effective for the entire analysis period have been considered (60 Supplier Units, including Error Supply Unit, and 215 Generator Units including Interconnector Units and Netting Generator Units).

Unlike previous years where the analysis had been carried on invoice totals at Participant level, the approach the MO has taken for this year's analysis is to focus on resettlement amounts to which the relevant VAT rate has been applied on Unit by Unit basis. An invoice issue date has been derived for each resettlement week or month billing period as appropriate. As the FCCR is applied at a Unit level, this has allowed us to determine the level of exposure incurred by each Unit more accurately. This approach was taken to cover further analysis as requested by the Regulatory Authorities on Units of different sizes and types.

Suppliers and Generators have been analysed separately.

Should a Participant, on any given day, be suspended or de-register from the Market, the Fixed Credit Cover should adequately cover all resettlement up to 13 months.

However it was noted that M+13 made up a small percentage of the total resettled (8.8%) over the entire analysis period with the greater exposure being at M+4 (91.2%). This means that the greater risk from a Participant is concentrated in the immediate 4 months following their exit from the Market. Based on this, a moving total of 16 weeks (4 months) total resettlement has been used as a reasonable indicator of such exposures. A roll back as far as 13 months would have meant that all data from the beginning of the Market should have been analysed to have a sufficient number of samples. This would have included periods affected by large amount of ad-hoc resettlement due to system errors in the first couple of years. The approach taken ensured that the analysis reflected a more stabilised level of resettlement and allowed for a more reliable future forecasting

3.5.2.1 Supplier Units

In terms of Suppliers (SU), payments can be either negative or positive and they generally follow a seasonal trend represented in the Figure 11 below which excludes the Error Supply Unit. Positive values indicate a risk to the Market, while negative values are remittance from the Market. As this is a net position, it indicates the risk as a whole for the Market, but not at an individual Unit level. This is mirrored by Error Supply Unit (ESU) in Figure 12 below.

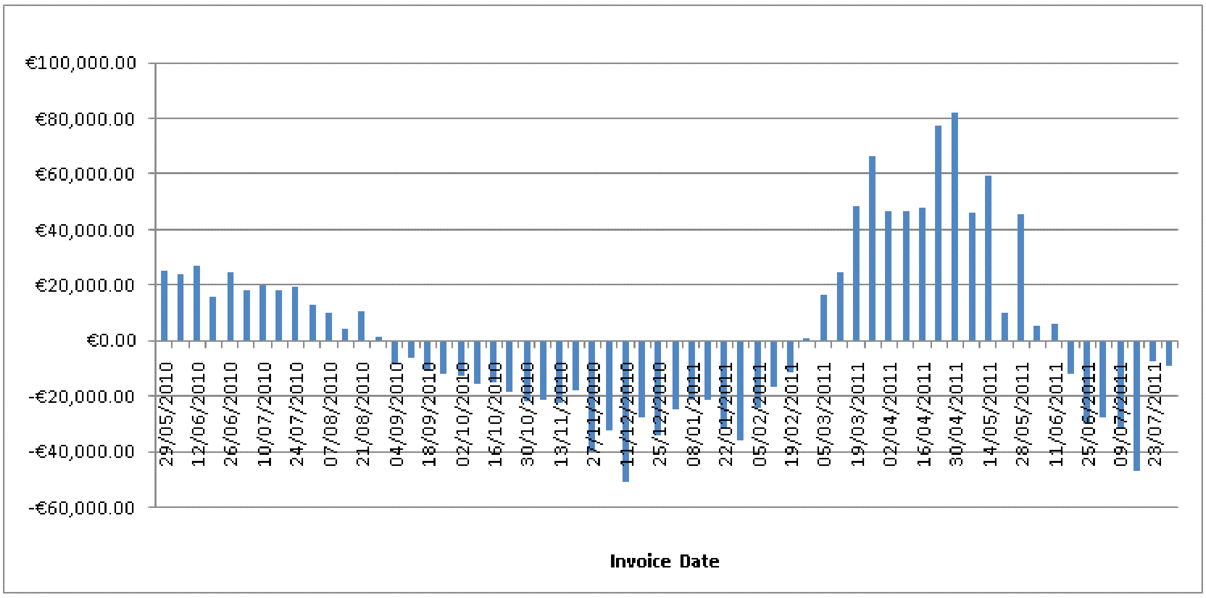

Figure 11 - Net Resettlement Market total excluding ESU

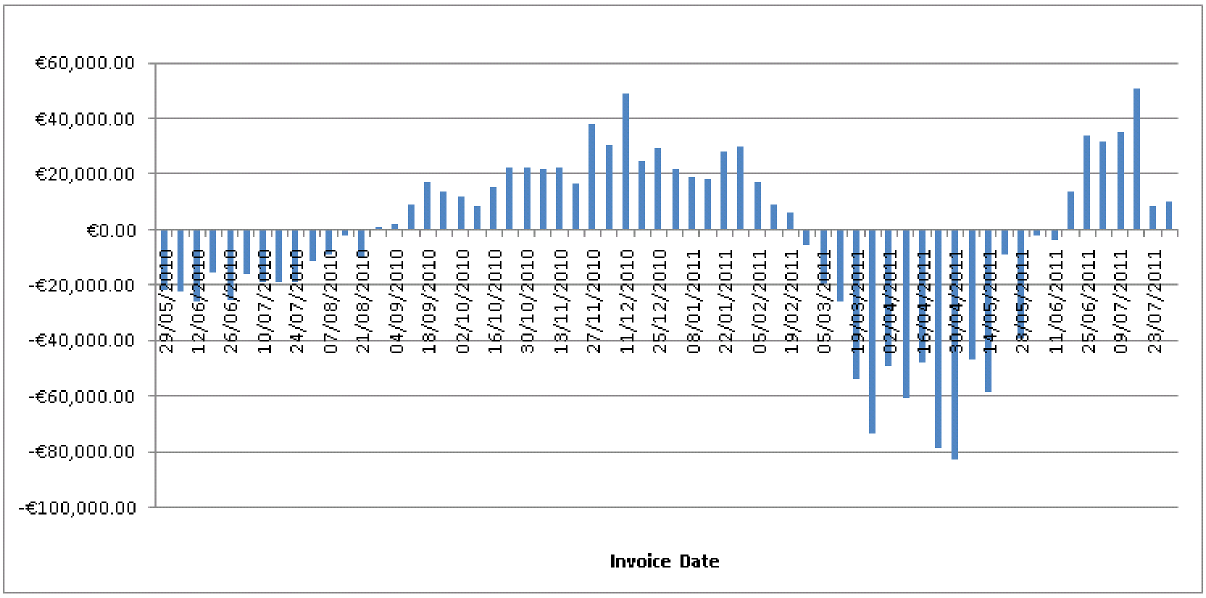

Figure 12 - Net Resettlement Market total for ESUs

Given the large variance in the average daily demand for each Unit, a trend has been identified, in previous reports, between the amount of resettlement and the size of the Unit based on the average of the daily demand over the study period. Figure 13 below illustrates this correlation for each SU, excluding Error Supply Units. Resettlement amounts and demand for suppliers have been represented as a percentage of the total to prevent disclosure of Supplier confidential data.

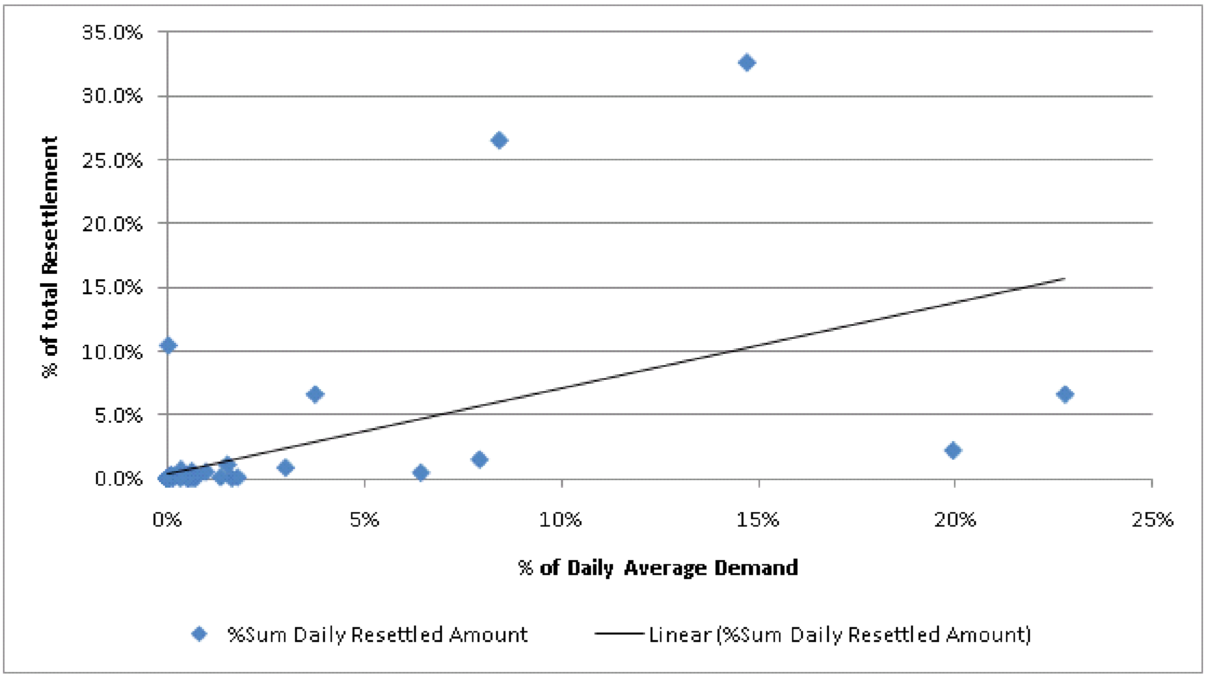

Figure 13 - % of Total RS amount for each SU vs. % of average daily demand

This is more evident once the detail from the majority of cases is examined closely by excluding outliers for the purposes of illustrating this trend.

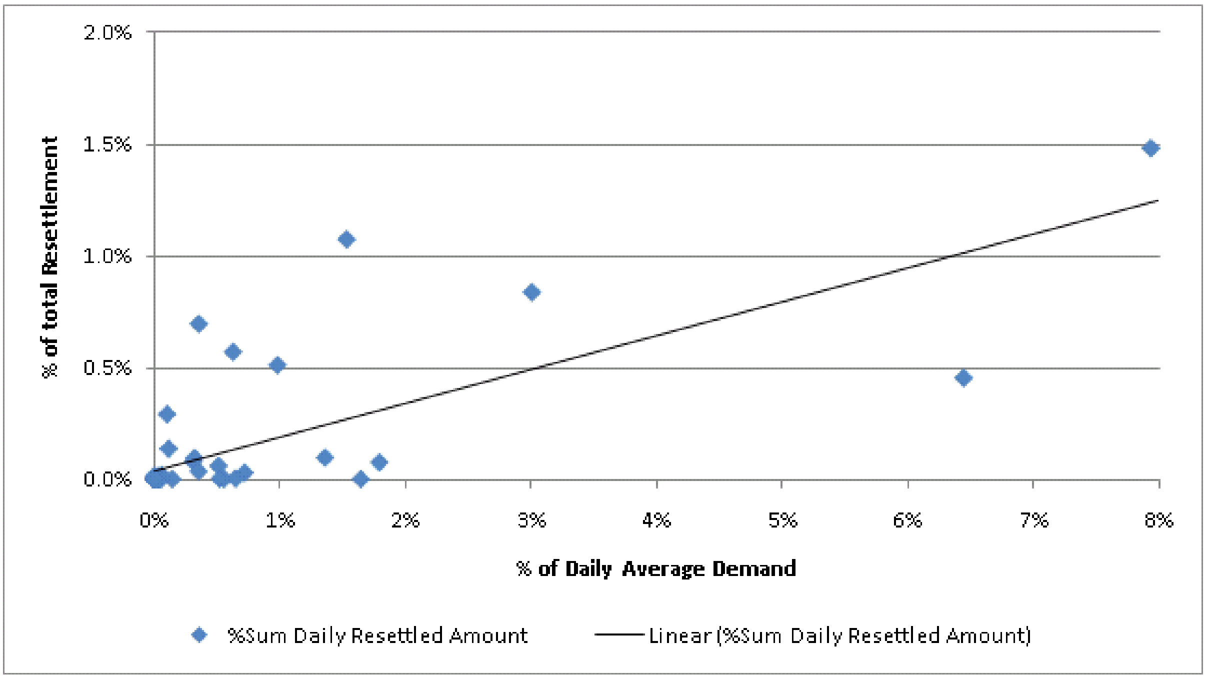

Figure 14 - Detail of resettlement vs. demand trend once outliers are not shown

This has allowed the calculation of an adequate rate per MWh of FCCR based on different level of resettlement aggregation either weekly or based on a rolling 16 weeks total resettlement.

When considering the risk incurred by the Market at any point in time, this would be represented by the highest value of the 16 weeks rolling total resettlement over the sample period for each Supplier Unit. Dividing this by the average daily demand in MWh, over the same period, a rate of €10.68 per MWh is produced which brings the maximum FCCR that should be required to cover all instances in the Market to just below €65,000.

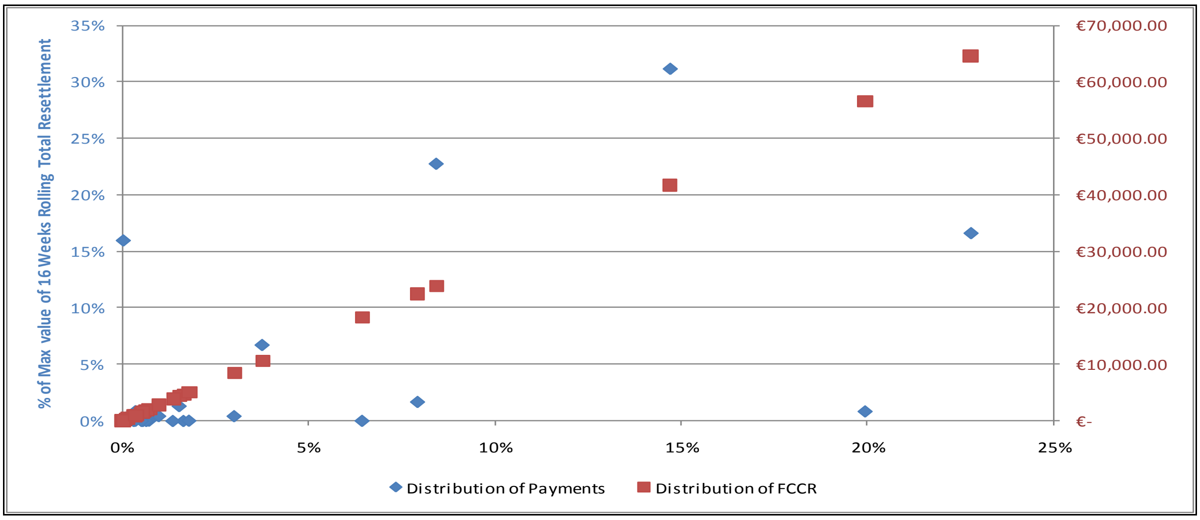

Figure 15 - FCCR requirement based on the calculation of a €/MWh rate with the max value of 16 weeks rolling RS amount

The same process has been repeated on a weekly basis as this represents the immediate risk that needs to be covered by the FCCR should a default happen. Both the maximum weekly value and the average have been considered in order to better evaluate the best outcome.

In the case of the maximum weekly resettlement amount, the resulting FCCR rate is 8.30€/MWh, which brings the highest potential requirement just below €50,000.

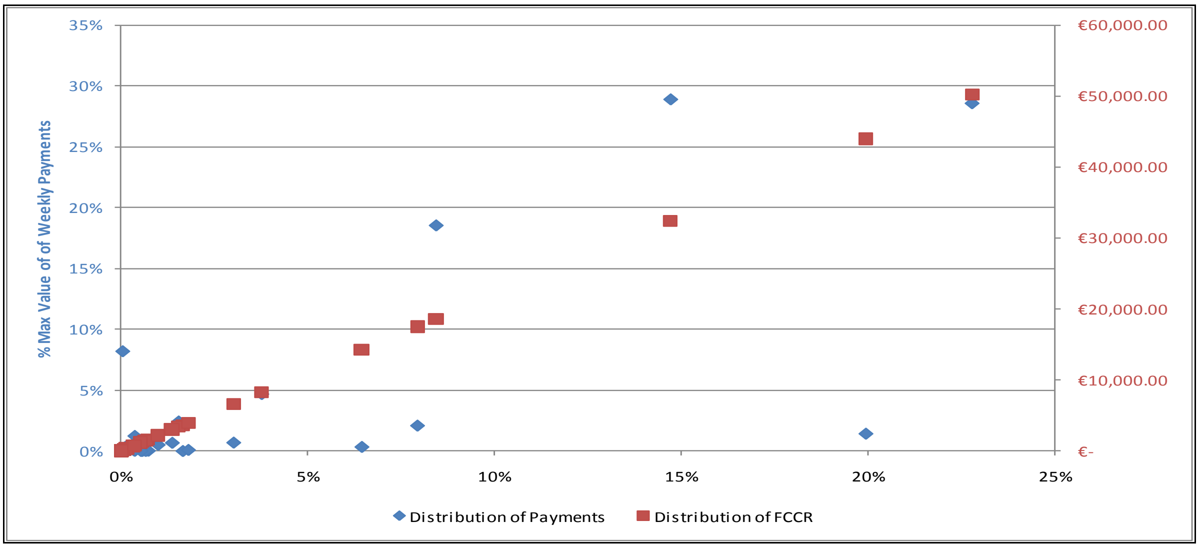

Figure 16 - FCCR requirement based on the calculation of a €/MWh rate with the max value of weekly RS amount

An average of all positive total weekly resettlement values resulted in a rate of 7.34€/MWh and a maximum potential FCCR of €45,000.

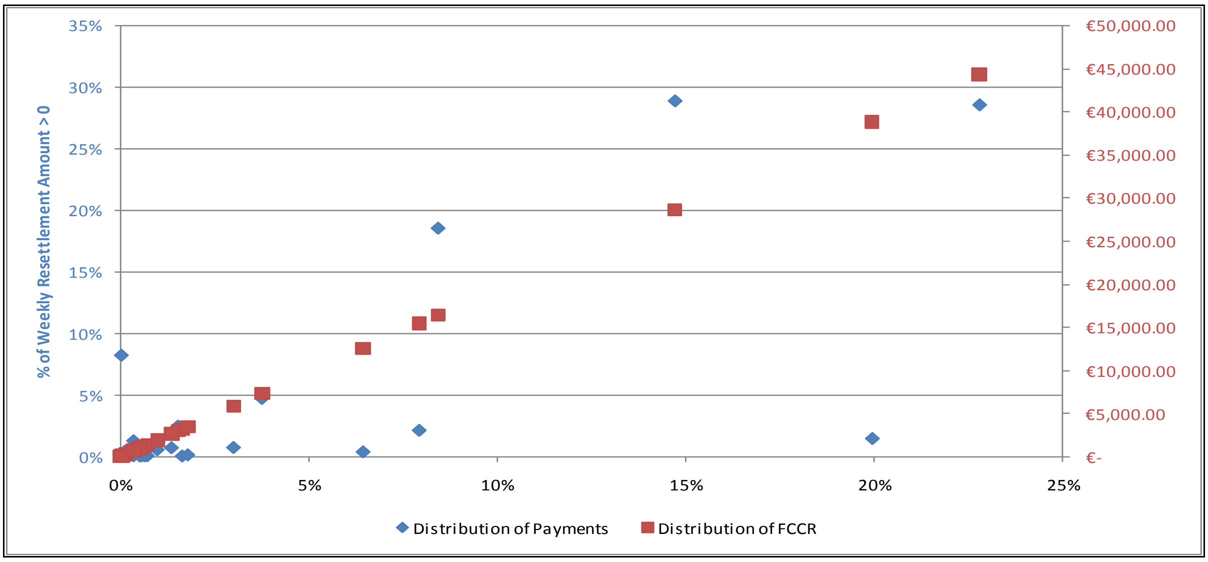

Figure 17 - FCCR requirement based on the calculation of a €/MWh rate with the average value of weekly Resettlement amount

By taking the extreme out of the equation the results represent a more balanced view of the majority of Participants' risk. The same rates, as in figures 15 to 17, are now shown in detail with the exclusion of the outliers. This indicates that a FCCR between €15,000 and €22,000 maximum would adequately cover 93% of resettled Participants in the largest instances recorded within the sample period. The average of the three rates is 8.77€/MWh.

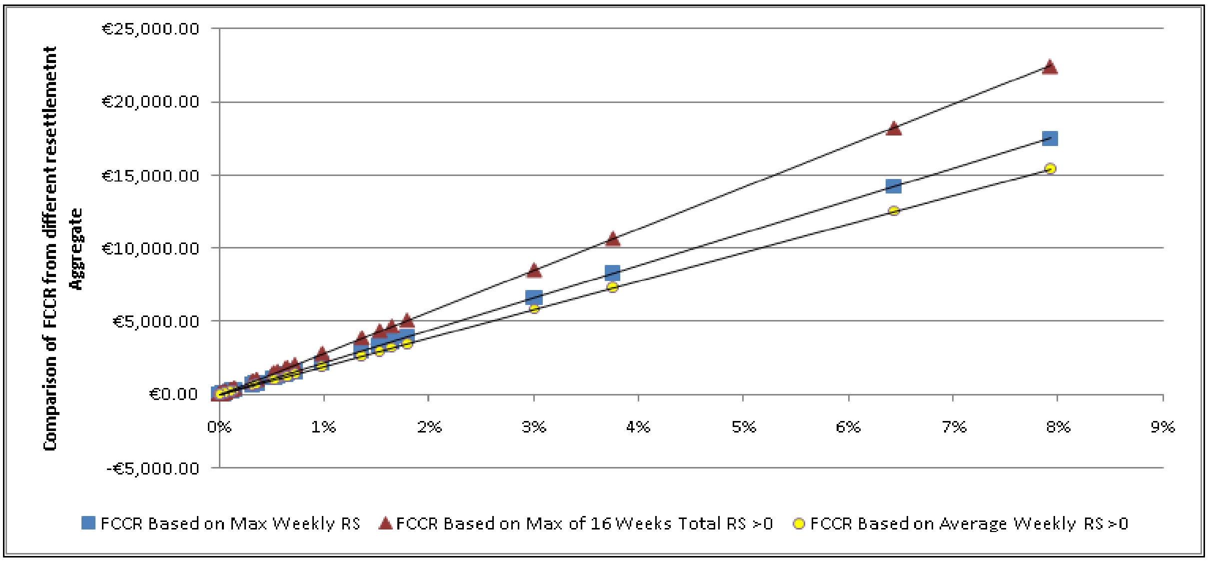

Figure 18 - Detail without outliers of FCCR with different RS aggregation

The scale of the resettlement figures for the remaining 7% (for which the highest weekly total was €330,000 and the highest value for the 16 weeks rolling total resettlement was nearly €2,000,000), could not be covered unless imposing a FCCR too onerous on the Participant.

3.5.2.1 Generator Units

With regard to Generator Units (GU), the analysis shows that across the sample period the risk to the Market is considerable lower than with Suppliers, both in quantity of resettlement and frequency, and that there is not a clear pattern based on the size or type of Unit.

Figure 12below shows the relation between the total resettlement amounts and the Registered Capacity for each Unit showing that a correlation between the two cannot be clearly established. This graph excludes both Interconnector and Netting Generators.

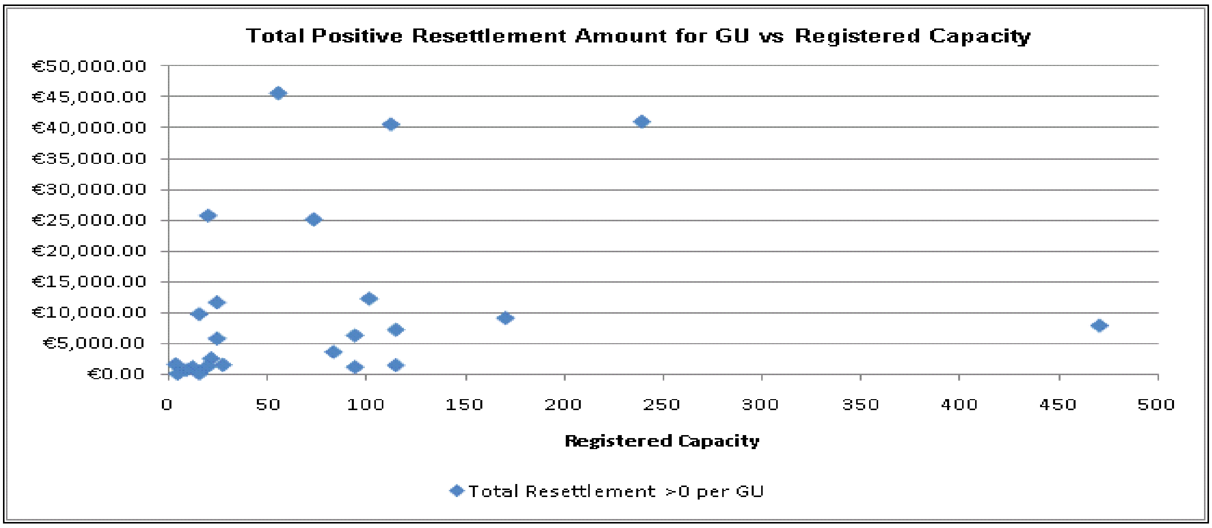

Figure 19 - Total RS amount > 0 for each GU vs. Registered Capacity

When considering all instances where the weekly resettlement total exceeded the current level of FCCR of €5,000, it was noted that the frequency of these events are extremely rare as the vast majority of such instances are covered. As Table 4 below indicates:

Level of FCCR	€1,000.00	€2,500.00	€5,000.00	€10,000.00	€15,000.00	€20,000.00
% of Coverage	98.6249%	99.1457%	99.3138%	99.6748%	99.8539%	99.9146%

Table 4 - % of instances covered by current FCCR.

However, when these events occur the amounts can be much higher (maximum reached is €42,000) and can occur for all Unit types and sizes.

Similar to the analysis performed for Suppliers, the MO has calculated a 16 week total rolling resettlement which represent the maximum risk at any given time should a Participant be suspended or de-register from the Market. The maximum value reached in the sample period was just above €42,000.

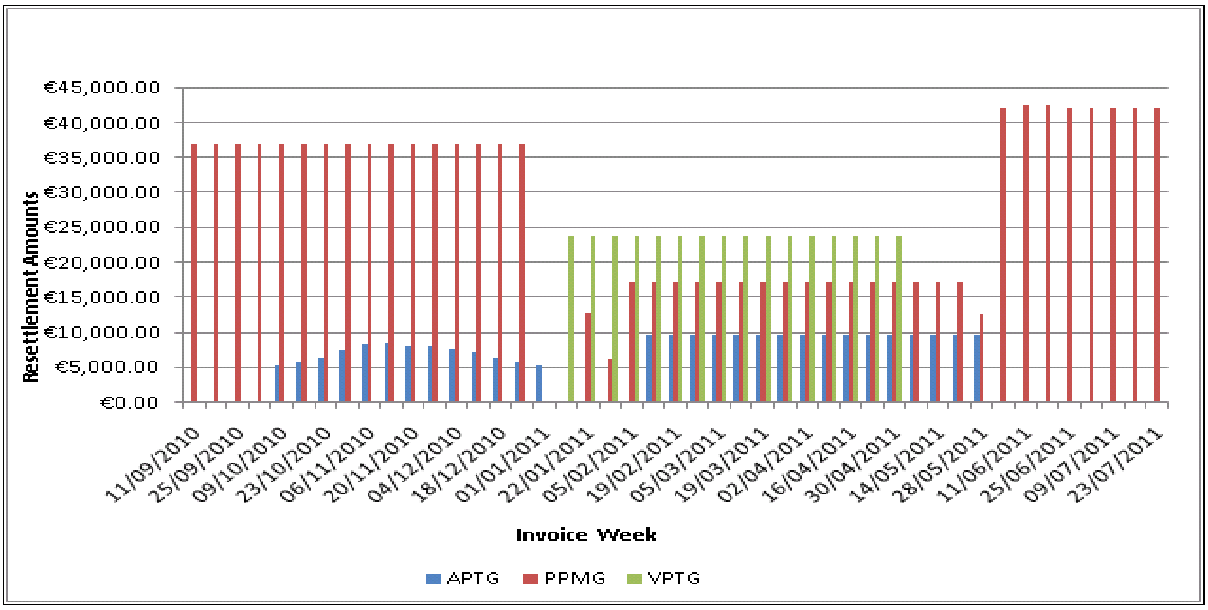

Figure 20 - Max of 16 weeks rolling total resettlement for all GU types > €5,000

Only Generator Units classed as PPTG never reached a value above €5,000, although they came close at €3,300.

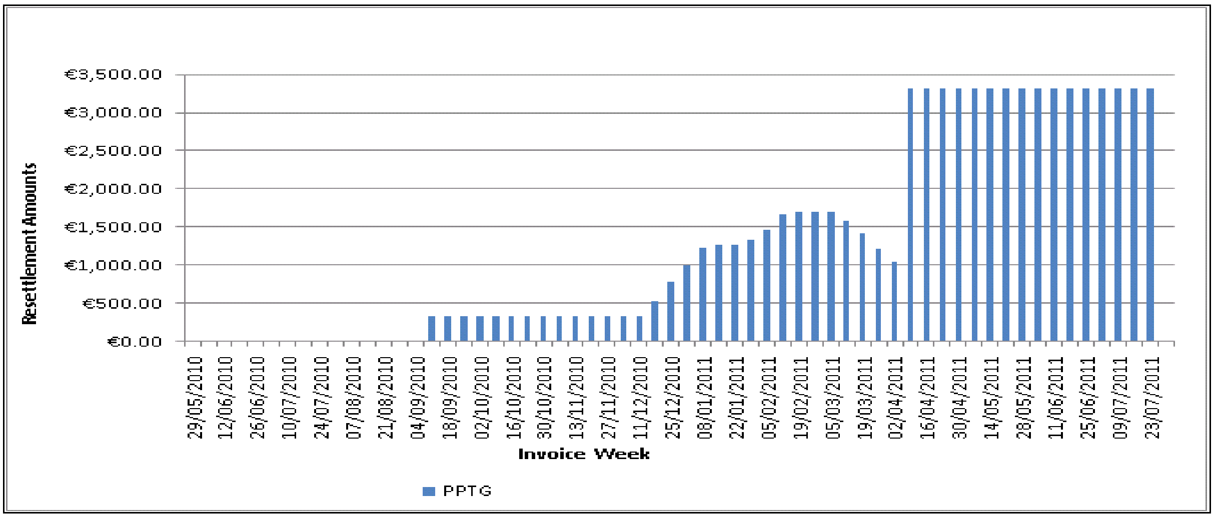

Figure 21 - Max of 16 weeks rolling total resettlement > 0 for PPTG

Similarly for Interconnector Units (IU) resettlement amounts were just short of €5,000.

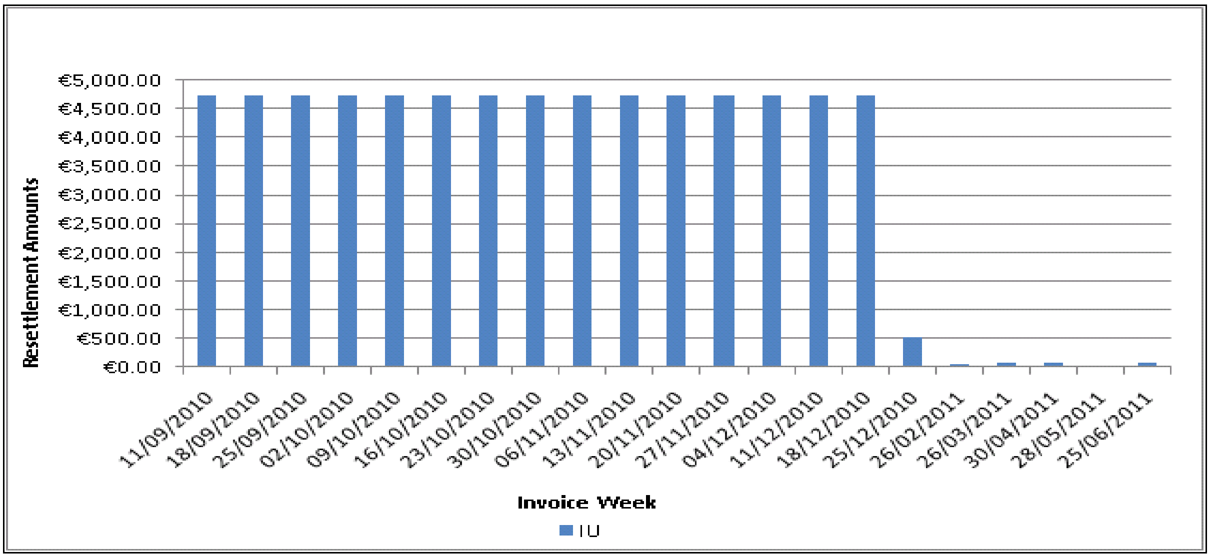

Figure 22 - Max of 16 weeks rolling total resettlement > 0 for IU

Netting Generators Units (NGU) have also been analysed and it was found that only a few instances in the region of €200 per day occurred while several were only for amounts less than €20.

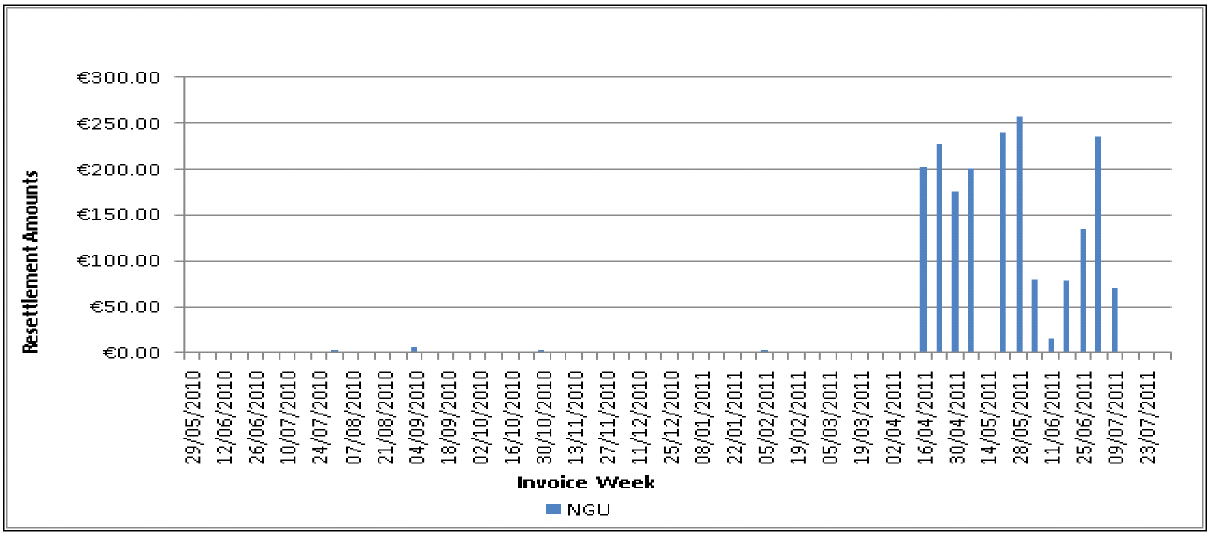

Figure 23 - Max of daily resettlement > 0 for Netting Generators

3.5.3 Conclusions

Trying to determine a FCCR figure that is appropriate for all Generators or all Suppliers, as noted in previous years Credit Parameter recommendations, is extremely difficult given the nature of resettlement and the variation in resettlement.

3.5.3.1 Supplier Units

For Supplier Units it is possible to indentify those Units that pose a greater risk to the Market based on historical average daily demand which the MO can calculate on a yearly basis. This means that, for new Units, forecast demand would be used to determine their Initial requirements until they became a Standard Participant.

Based on the results, it would appear to be more appropriate to apply a different value of FCCR for each Supplier based on their demand.

While Suppliers are clearly a risk in the Market at initial settlement stage, resettlement can either lower or increase that risk. Often the net position of Suppliers can be negative due to the fact that they are owed monies from the Market at resettlement stage. However, when this is not true, amounts can be significantly high, in particular for Suppliers with a greater demand. Although the net amount over the full year might be close to neutral, the risk of a supplier exiting the Market with such large resettlement pending is high.

In the case of larger Suppliers, the scale of the variance above the current FCCR is so vast that it could only be covered with level of cover that would impose an undue burden on the Participant; however, the instances of such variances outside the FCCR decrease once the FCCR is raised to a level of €15,000.

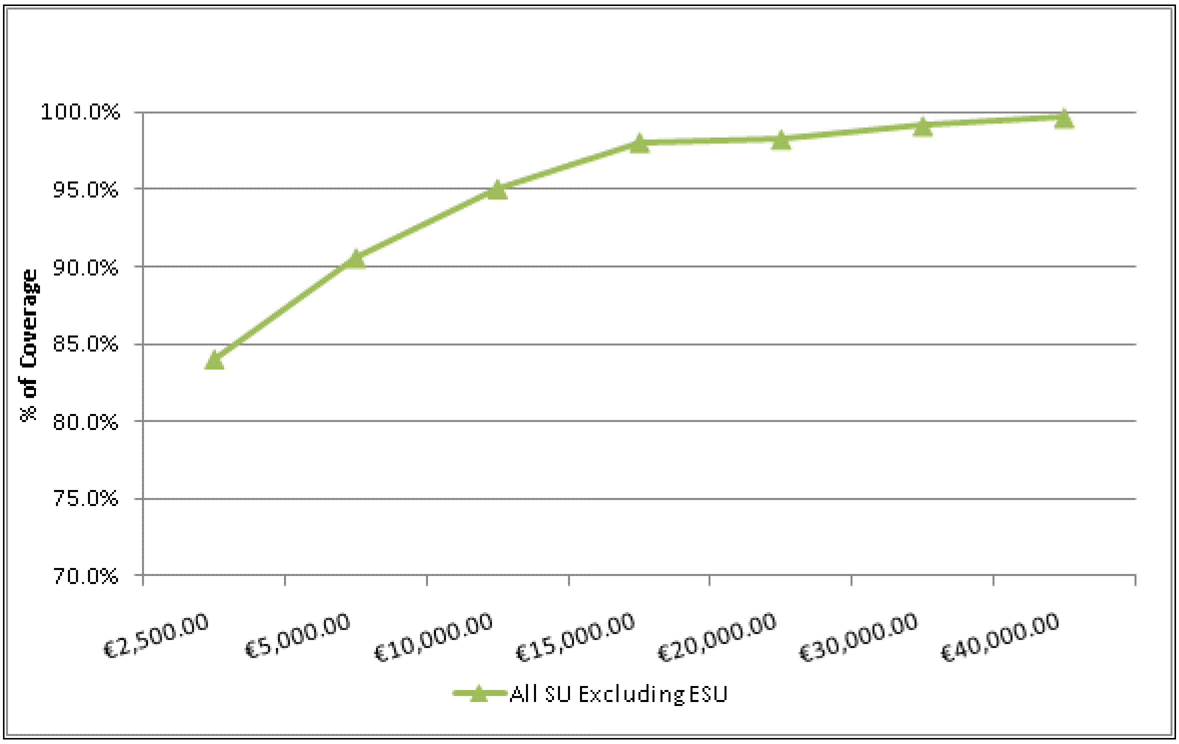

Figure 24 - Percentage of resettlement covered by various level of FCCR for all SU excluding ESU

Based on this the MO would recommend a rate of 8.77€/MWh. This is the average of the three rates calculated in our analysis based on the weekly average resettlement and the maximum resettlement incurred in the Market over a week or a 16 weeks period (4 months).

The MO believes this represents the best compromise between covering the worst case scenarios or the average Market risk at any point in time.

The MO would inform Participants, on a yearly basis, of the average daily demand that will derive their FCCR for the coming year. This will be based on historical data or in the case of New or Adjusted Participants, their forecast data. The MO would also recommend to cap the maximum FCCR output value to €15,000 as higher values would not significantly improve the cover of resettlement.

Finally, the number of resettlement defaults with reference to the same period, were also reviewed and found that 7 of the 9 defaults were for less than €0.05, one for €11 and one for €870. These were covered by excess cash collateral in most cases and are an indication that FCCR would have been more than appropriate to cover any one-off payment defaults that have occurred in the sample period. Based on this, FCCR floor value of €1,000 is advisable as minimum value is in line with the largest default amount observed in the sample period. Also with the deregistration of the larger ESU in early 2011, variances in demand might increase, therefore a lower value would not be recommended at this time.

3.5.3.2 Generator Units

With regard to Generator Units, the analysis shows that the current level of FCCR at €5,000 is adequate for all Generators types. Although resettlement can reach level that are much higher, the frequency of those happening is very low and does not warrant an increase.

Interconnectors Units have resettlement values just below the FCCR and considering future Market rules, with additional Interconnectors becoming effective and the potential for super positioning, it would not be advisable to lower the current value.

For Netting Generator Units the current FCCR is excessive based on the level of resettlement these Units get. A value of €1,000 would sufficiently cover all instances observed in the sample period and constitute sufficient security for those Units.

The analysis of the exposure based on registered capacity, did not offer any indication that a different level of FCCR per Unit should be applied.

3.5.4 Recommendation

Based on the analysis carried out, The MO proposes that the 2012 Fixed Credit Cover Requirement for Suppliers is applied as follows:

- A rate of 8.77€/MWh of average daily demand subject to a minimum value of €1,000 and a maximum of €15,000

The MO would carry out an initial calculation of all Suppliers demand based on the previous year of finalised Meter data (post M+13) available. Forecast data for new Supplier Units would be used instead.

With regard to Generator Units, SEMO recommends that the Fixed Credit Cover Requirement for 2012 is maintained at €5,000 for all Generator Units and reduced from €5,000 to €1,000 for Netting Generators.