2010

SEM Parameters for the Determination of Required Credit Cover

Document History

Version	Date	Author	Comment
2.0	31st August 2009	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 2010.

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 2010.

- Historical Assessment Period for Billing Period
- Historical Assessment Period for Capacity Period
- Analysis Percentile Parameter
- Credit Cover Adjustment Trigger
- Maximum Level of the Warning Limit
- 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.
- *Maximum Level of the Warning Limit* – this sets the point above which a Participant cannot change their Warning Limit. When the Required Credit Cover to Posted Credit Cover ratio exceeds the Warning Limit, the Participant will be notified.
- *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.

2 Recommendations

Based on the analysis performed the credit parameters shown in Table 1 are proposed by the MO for use in Trading Year 2010. These proposed values are considered the best combination to ensure appropriate levels of Credit Cover in SEM.

Credit Cover Parameter	**2009 Approved Value**	**2010 Proposed Value**
Historical Assessment Period for Billing Period	100 days	100 days
Historical Assessment Period for Capacity Period	100 days	**90 days**
Analysis Percentile Parameter	1.96	1.96
Credit Cover Adjustment Trigger	30%	30%
Maximum Level of the Warning Limit	75%	75%
Fixed Credit Requirement for Supplier Units	€30,000	**€20,000**
Fixed Credit Requirement for Generator Units	€5,000	€5,000

Table 1 - Proposed 2010 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.

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 2010.

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.

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 SEM combined with forecast volumes provided by the Participants.

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 50% of the total exposure of a Participant and will have 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 2009.

A key dependency on the duration of the HAPB, and also the HAPC, is the Supplier Suspension Delay Period. It is assumed that the current value of 14 calendar days will not change during 2010. It is highly recommended that should the Supplier Suspension Delay Period be amended a review of the credit parameters is completed.

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.

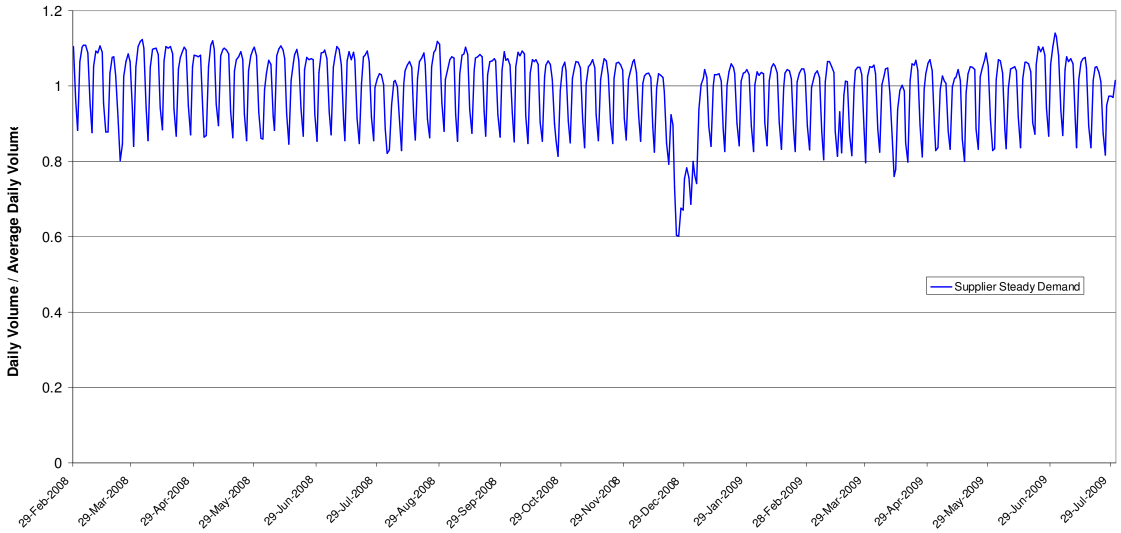

Figure 1 - Normalised Typical Supplier with Steady Demand Profile

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.

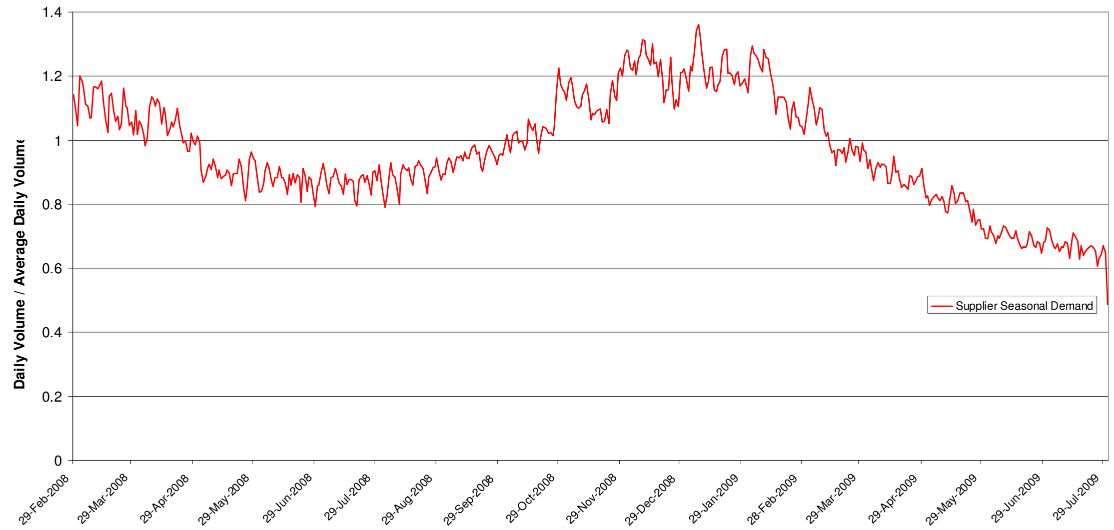

Figure 2 - Normalised Typical Supplier with Seasonal Demand Profile –

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. In the sample case chosen this related to a 180% different between minimum and maximum demand values over the year.

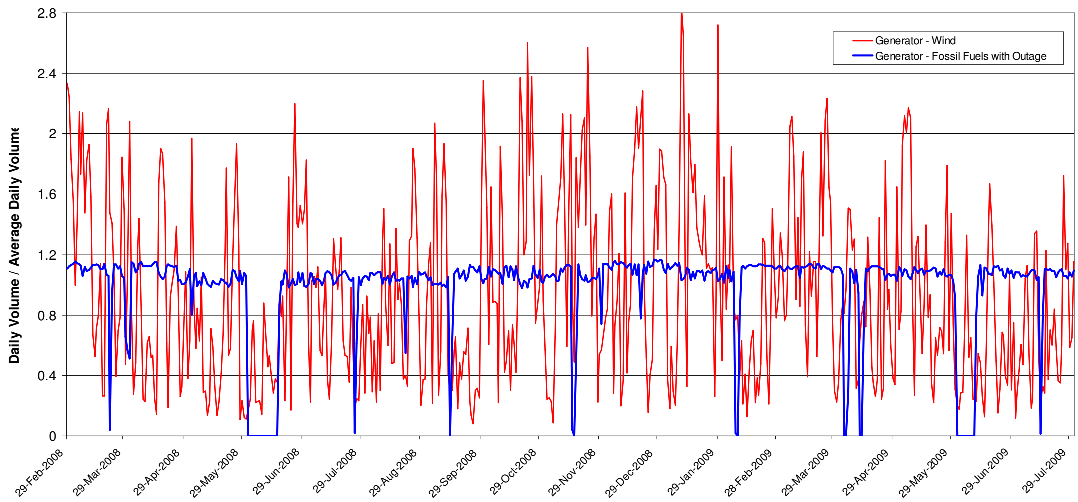

Figure 3 - Normalised Typical Wind and Thermal Plant Generation Profiles

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 have a predictable profile which is interrupted by periods of plant outage (e.g. June 2008 and May 2009 in the above example).

Each of these four typical demand/generation profiles was then modelled 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.

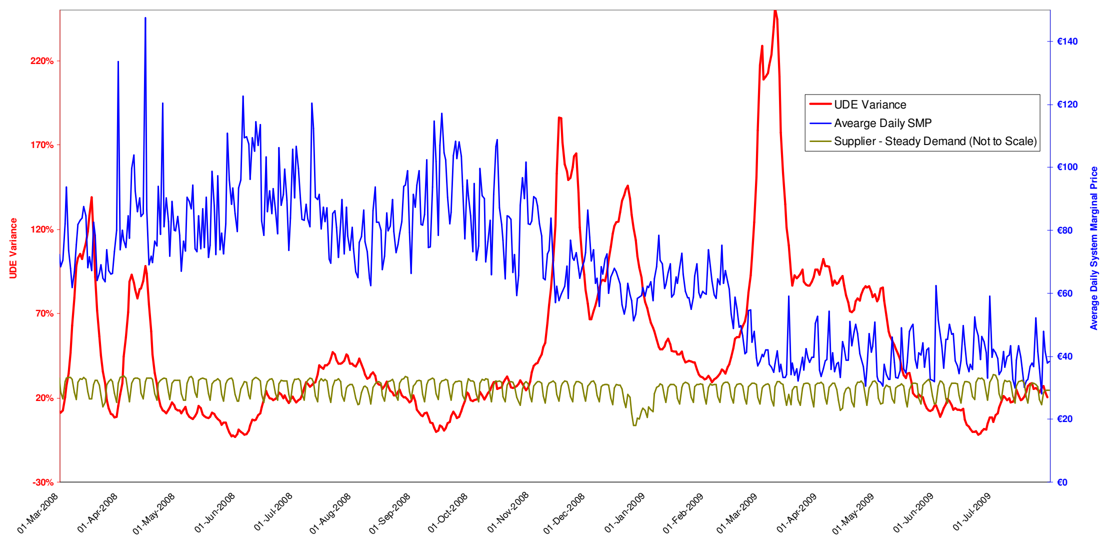

Figure 4 – Effect of Price and Demand on UDE Variance

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 Figure 4 in the periods around June and September 2008. This is further emphasised by the fact that during these same periods of under-collateralisation 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 practicable.

Figure 4 also illustrates that a drop in SMP coincides with a peak in the UDE variance, meaning the Participant will be over-estimated The two peaks shown in November and December 2008 can be attributed to high fuel prices which kept SMP high during the summer and autumn of 2008. This was followed by the subsequent sharp decrease in fuel costs, and therefore SMP, in November 2008. A similar drop in SMP occurred in March 2009 causing the 3rd peak in UDE variance shown. A drop in demand due to the downturn in the economy may have also contributed to these decreasing SMP values. The effect of fuel price drops and decreasing demand created an unusual scenario where the SMP was lower during the winter season than during the summer, effectively reversing the typical seasonal trend.

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

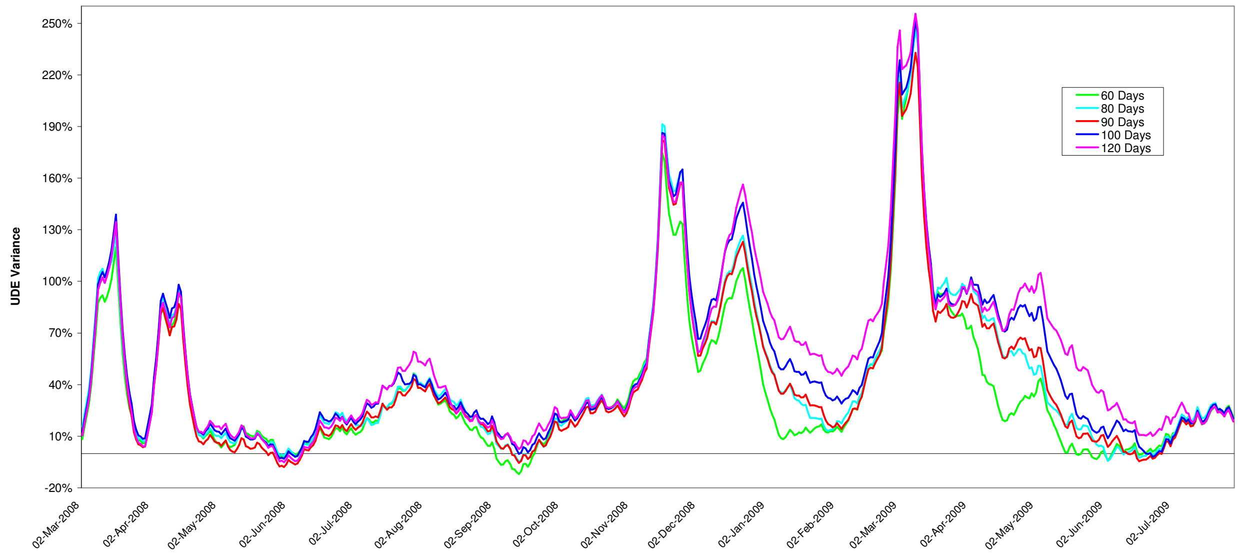

Figure 5 –Effect of Different HAPB on UDE Variance for Supplier with Steady Demand

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%). On the 13th of September 2008 for example the different HAPB values of 60, 80, 90, 100 and 120 days resulted in an UDE Credit Cover Requirement under/over-estimated by -12%, -5%, -5%, 0% and +2% respectively. It is 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 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.

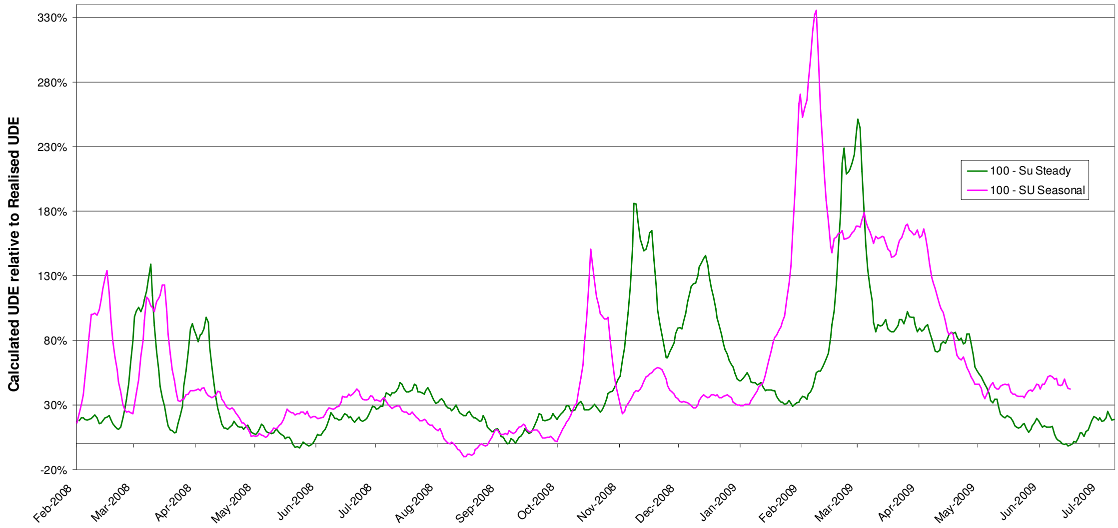

Figure 6 –UDE with Varying Demand Profiles for same HAPB

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 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.

Although there is no obvious solution to improve Credit Cover calculations for wind generation which is inherently variable and unpredictable, for Generators with planned outages the introduction of modification 28_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.

3.1.3 Conclusions

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 2010 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.

Putting the Capacity component of the UDE into context it typically accounts for 14% of Participant total exposure and is relatively small compared to the UDE Energy component which accounts for typically 50% of Participant total exposure. The remaining 36% of total exposure comes from the 'known' exposure described in Section 1.4.

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.

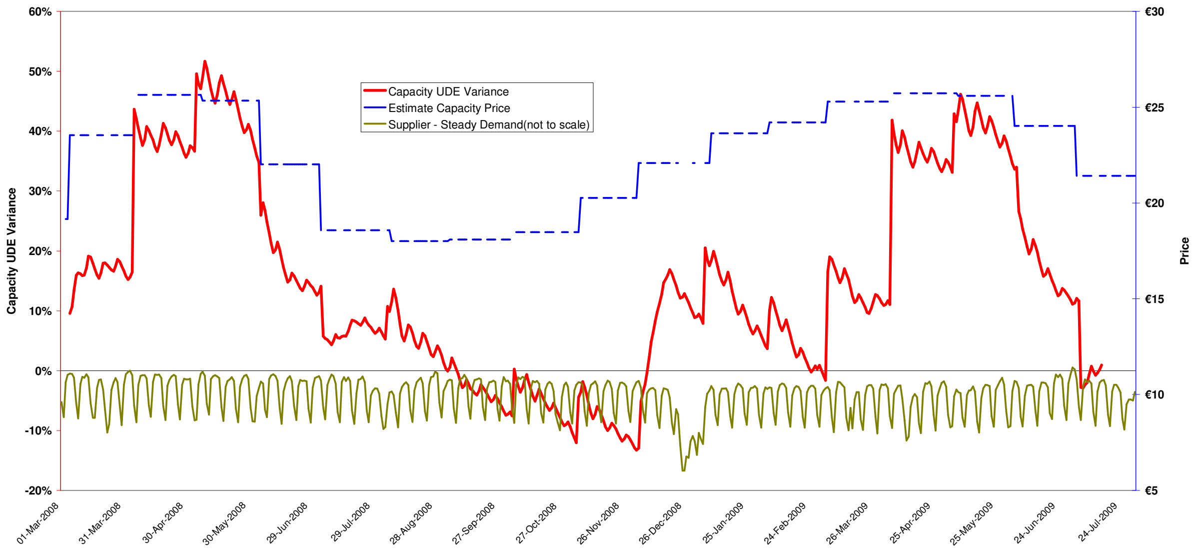

Figure 7 – Effect of Price on Capacity Calculated Undefined Exposure

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. Typcially 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 are 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-collateralised and where the percentage is less than zero the Participant is under-collateralised.

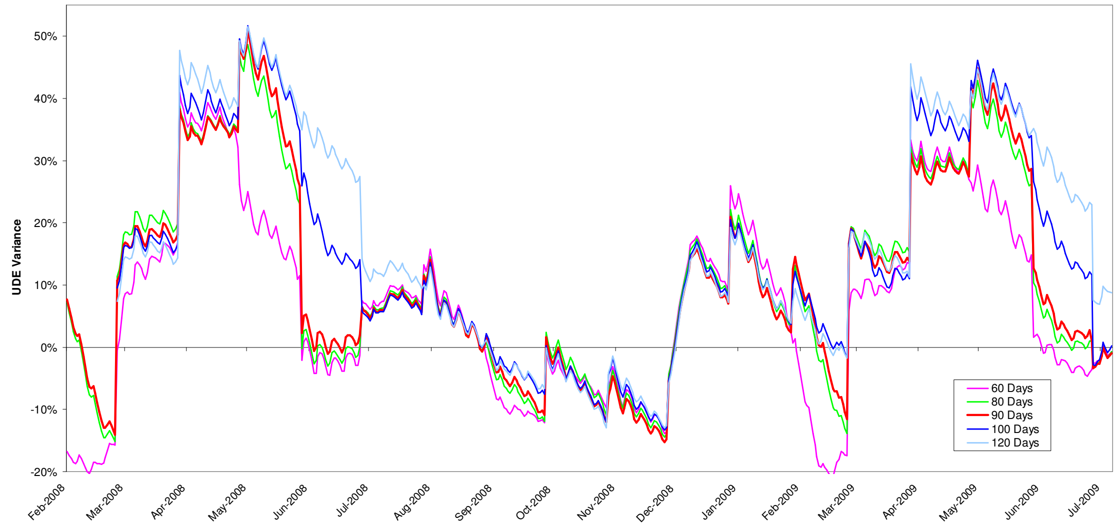

Figure 8 – Capacity Market - UDE Variance with Different HAPC

Based on Figure 8 the use of a HAPC of 90 days appears to be a good compromise between reducing the occurrences of under-estimation and reducing excessive over-estimation. It also has an additional advantage over the existing 100 days HAPC value currently used in the market. From a practical point of view when a Participant becomes an Adjusted Participant, due to a step change in their demand/generation, 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 the existing HAPC of 100 days must wait an elapsed time of approximately 120 days before a Participant can become standard and use historical data. Using a HAPC of 90 will mean that Participants would not be delayed an additional 20 days before switching to historical data which should provide a more accurate calculation of UDE.

Figure 8 shows that the profiles for 90 generally provides a lower level of over-estimation than the 100 day HAPC and a similar trend for under-estimation. Also given HAPC only accounts for 14% of the total exposure a change to 90 days should have minimal effect on the overall exposure of the market. In fact using 90 days will benefit the accuracy of the credit calculations as it will allow Energy to be calculated after only 100 days.

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 has a far greater effect on how accurately the total calculated UDE matches the total realised UDE. The Capacity UDE only accounts for a small component of this total at typically 14% of total exposure where as Energy UDE is 50%.

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 2010 be reduced to 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 90th, 95th or 98th 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.

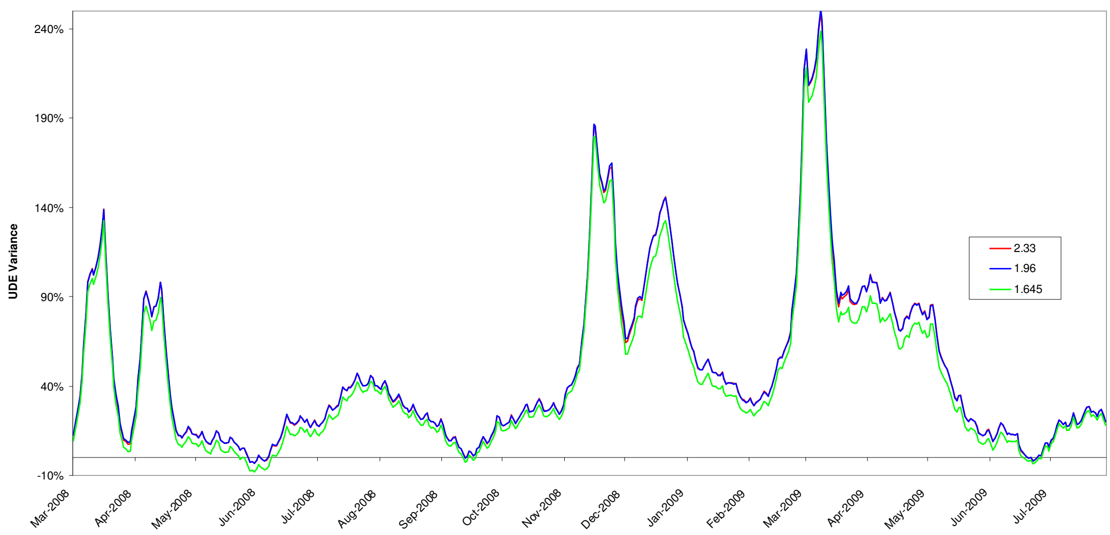

Figure 9 –Different Analysis Percentiles Effect on UDE Variance

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

3.3.3 Conclusions

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

The HAP 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 2010.

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 is 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.

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

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 for the Credit Cover Adjustment Trigger is based on actual settlement volumes for SEM Participants for a calendar year period from July 2008 to June 2009. This analysis period includes all seasonal changes in demand and outage periods.

The analysis assumed that Participants had perfect foresight. Meaning that their forecast volumes for the next four billing periods were identical to the actual volumes metered.

Participants that entered the SEM after the start of July 2008, or who ceased trading during the analysis period year were not included. This provided a total of 44 Participants used in the Credit Cover Adjustment Trigger analysis. 16 of the Participants were Suppliers, 26 were Generators and 2 were Interconnector Users.

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 and modification 26_08 had been active from the start of July 2008, 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.

Group Ref	Participant Type	Apparent Adjustment Reason	Adjustment Trigger							
			5%	**10%**	**15%**	**20%**	**30%**	**40%**	**50%**	**60%**
1	Supplier	Low Demand	4	4	4	4	3	3	3	3
2	Generator	Wind	17	17	17	17	17	17	17	17
3	Generator	Outage Related	9	9	9	8	8	6	6	5
4	Interconnector	Change Trading Pattern	2	2	2	2	2	2	2	2
5	Supplier	Change Customer Demand	12	12	10	6	3	2	2	2
	Total		**46**	**44**	**42**	**37**	**33**	**30**	**30**	**29**

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

From Table 3 it can be seen that almost all Supplier Units with very low demand (i.e. <50MW) and all wind generation, groups 1 and 2 respectively, 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 anyway. 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.

Groupings 3, 4 and 5 at the bottom of Table 3 appear to have Adjustment reasons that are more predictable e.g. Generator outage related or changes in customer demand.

For the Suppliers with an apparent change in customer demand (Group 5), it appears that for all Suppliers in the study group an Adjustment Trigger of 15% or less would involve most of them declaring as Adjusted at least once a year.

For the Generators with apparent outage related events (Group 3) an Adjustment Trigger of 15% or less would involve all thermal plant needing to be declared as Adjusted at least once per year.

This would indicate that an Adjustment Trigger of 30% would appear to provide the best balance of catching the larger step changes for Suppliers and the majority of the Generator outage step changes while minimising the total number of Participants that need to be classed as adjusted in SEM.

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 64% of the total Participant exposure. If a Participant's demand is out by 15% the Credit Cover will be out by a maximum of 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 2010 as this would cover the majority of step change events that are foreseeable for both Supplier and Generator Participants

3.5 Maximum Level of Warning Limit

3.5.1 Context

The warning limit is a parameter used to trigger the issuance of a warning notice to Participants whose Credit Cover Requirement is nearing their Posted Credit Cover. A warning notice is issued to a Participant where the ratio of Required Credit Cover to Posted Credit Cover is greater than or equal to the warning limit and the ratio has changed from the preceding Credit Cover calculation day.

The warning notice is for informational purposes only and does not require a Participant to take action. It is separate and distinct from the Credit Cover Increase Notice (CCIN) which issues when a Participant's credit cover requirement is greater than their Posted Credit Cover. A Participant must take action to resolve a CCIN within 2 working days.

3.5.2 Analysis

In the twelve months between July 2008 and June 2009 there were 1162 warning notices issued in the SEM, equating to approximately 5 per working day.

The following observations are of relevance in proposing the warning limit for 2010:

Since the Market Start there have been no requests by any Participant to set an individual warning limit level lower than the default level of 75%. This indicates that Participants do not see value in having a warning limit lower than 75%.

All CCINs have been remedied before suspension orders have been required indicating that Participants are being provided with adequate and timely information with the current warning limit level and are ready to act on any events that cause a CCIN to occur.

There appear to be three types of Participant management of Credit Cover in the SEM.

- ***Generators - whose Credit Cover requirement does not change from day to day***
  These Participants tend to lodge the Fixed Credit Requirement needed for resettlement in Cash or Letter of Credit (LC) and then require no further management.
- ***Suppliers - who use LCs or Cash Collateral, and not Settlement Reallocation Agreements (SRAs)***
  These Participants tend to have reserves of collateral in place to manage the weekly or monthly peaks in Credit Cover requirement without the need to actively change their Posted Credit Cover.
- ***Suppliers - who use SRAs***
  These Participants tend to have a more dynamic management of Credit Cover, either putting SRAs in place well in advance, or where necessary actively managing their SRAs on a daily basis to match their daily Credit Cover requirement. These Participants also have more variation in their Credit Cover requirement based on when they lodge SRAs.

Looking at historical data there are five Participants, all Suppliers, that regularly receive warning notices at present. Three of these are Participants that use LC or Cash, but who operate above the 75% warning limit for the majority of the time. The other two are Suppliers regularly use SRAs to manage their Credit Cover Requirement.

One of the Suppliers who uses LCs and regularly receives warning notices does so because over 75% of their Credit Cover Requirement is Fixed Credit Requirement. Unless this Participant posted an excessive amount of Credit Cover, they would never operator outside the 75% threshold.

Feedback from Suppliers who use SRAs to manage their collateral is that the warning notices are of little consequence and it is the CCINs that are typically the trigger for immediate Credit Cover action. This would indicate for these Suppliers that receiving warning notices may in fact lead to a higher risk of missing a CCIN.

Based on this feedback and the historical information related to warning notice issuance in the SEM to date, the MO proposed a modification (Mod 54_08) to allow Participants to set their own warning limit. This limit could be above or below the default warning limit used in the SEM - dependent on the Participant's specific situation and requirements. The modification was approved in February 2009 and should become effective from the next market system release scheduled for October 2009.

Since the implementation of Day 1+ in January 2009 Participants have also had daily access to Credit Cover reports. This has provided Participants with more timely information to manage their Credit Cover requirement and further reduced the relevance of warning notices.

3.5.3 Conclusions

The relevance of warning notices to Participants is dependent on their individual circumstances and methods for management of their Credit Cover Requirement. While it is prudent to provide a default warning limit for the SEM, this default warning limit is not appropriate for all Participants. Particularly those that regularly receive warning limits due to their Credit Cover management approaches.

3.5.4 Recommendation

The MO would recommend that the current Warning Limit of 75% is maintained for 2010 as the default. This will give guidance for new Participants until such time as they become familiar with the Credit Cover process and they can then make an informed decision to increase or decrease their individual warning limit once modification 54_08 is implemented.

3.6 *Fixed Credit Cover Requirement*

3.6.1 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.

3.6.2 Analysis

The analysis for the FCCR was based on actual resettlement invoice amounts, M+4 and M+13, for SEM Participants from the July 2008 through to August 2009. Based on this analysis Table 4 below provides the average resettlement per Unit. A negative value indicates where resettlement determined further money was owed to a Participant, a positive value indicating where a Participant owed money to the SEM and there was an inherent credit risk.

Unit Type	Average Resettlement Per Unit
Generation	€ 31,425
Supply	- € 132,668

Table 4 - Average Resettlement per Unit Type

Table 4 shows Generators on average owe money to the market due to resettlement. Suppliers appear on average to be owed money due to resettlement.

This result is somewhat counter intuitive as for initial settlement Suppliers owe money to the market (have a positive exposure) and Generators are owed money by the market (have a negative exposure). However for corrections between initial and resettlement the flow of money may be either way.

Over the past year the general trend in resettlement appears to be that, on average, more payments have been made back to Suppliers and more charges due by Generators due to resettlement.

Further analysis of the underlying data identified certain types of units distort the figures in Table 4.

3.6.2.1 Generator Units

Table 5 provides the average resettlement per Unit broken down further into the different Generator Unit types.

Generation Unit Type	Average Resettlement Per Unit for all Generators
Generators	€ 739
Interconnector Units	€ 253,901

Table 5 - Average Generator Resettlement per Unit Type

From Table 5 it can be seen that the Interconnector Units, which are classed as Generators by the Code, have been incurring significant resettlement charges. This distorts the average Generator resettlement amounts provided in Table 4.

Looking in more detail at the non-interconnector Generators, the average resettlement amounts for each are provided in Figure 10 below. This graph illustrates that although the average resettlement per unit for Generators is € 739 the values are extreme ranging from - € 40,000 to over € 100,000 in average resettlement per Unit

Having a FCCR for Generators of € 5,000 per Unit would on average cover approximately 72% (21/29) of the Generator Units average resettlement amounts. This value is seen as being low enough to not unduly burden Generators while providing a reasonable level of credit cover for resettlement.

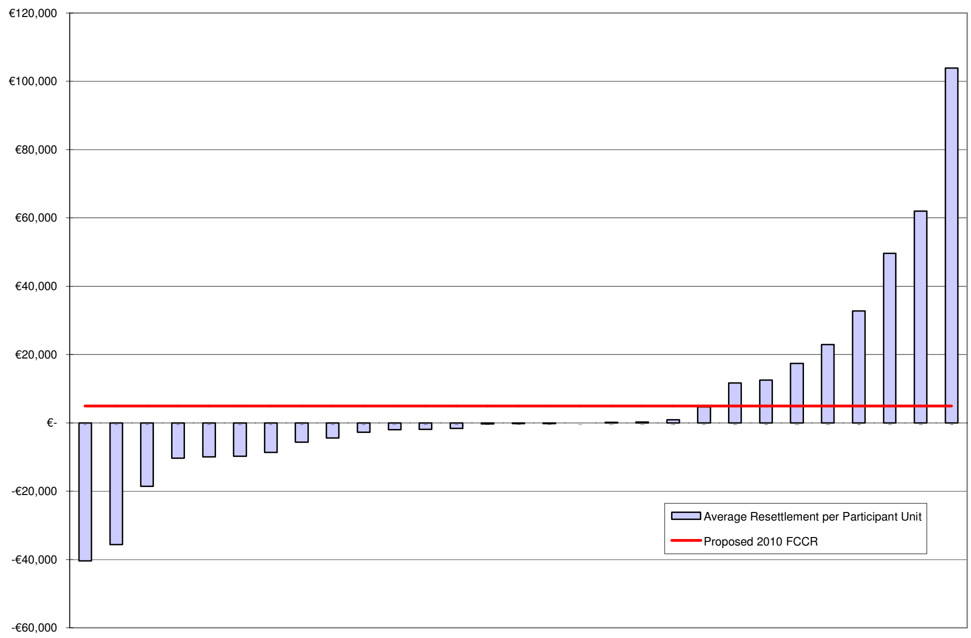

Figure 10 – Variance in Generator Average Resettlement per Participant

A secondary consideration when setting the FCCR is the number of defaults that occur for Generators. Since Market Start there have been 32 defaults by Generators on paying Energy or Capacity resettlement invoices. In total 18 of the 25 Generators in the SEM have defaulted at some time on resettlement payments. Default amounts range from €0.01 to over €2,000,000. Of these 32 defaults, 21 have been resolved within a few hours of the default. However 11 have required drawing FCCR indicating that Generators do pose a credit risk to the SEM particularly for resettlement. From Figure 11 having a FCCR for Generators of € 5,000 per Unit would on average cover approximately 84% (27/32) of the Generator defaults that have occurred since market start.

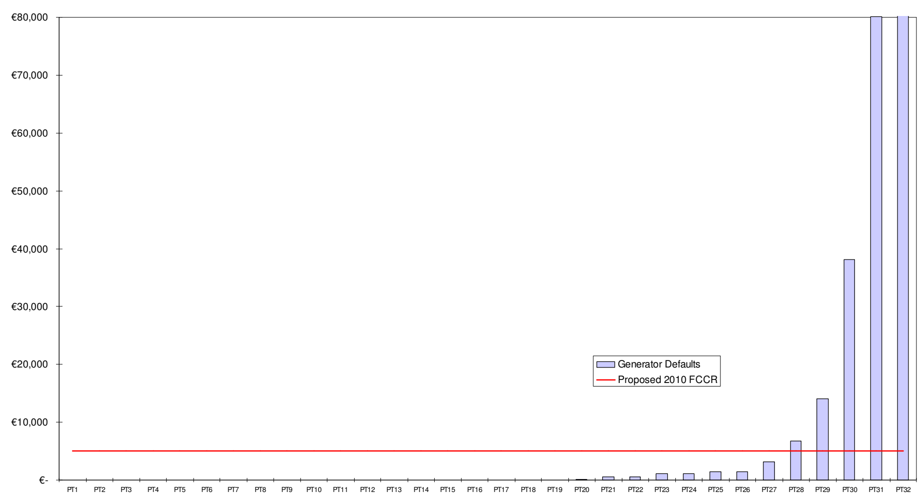

Figure 11 – Generator Defaults

The MO is reticent to suggest a FCCR value lower than the current value of € 5,000 due to the defaults we have seen in the market to date. If a level of FCCR is not maintained there is also a very real likelihood that bad debt situations will become more frequent, which impacts on all payments to creditors in the SEM. Maintaining a nominal amount of FCCR for Generators will help to reduce the likelihood of bad debt provisions taking effect.

3.6.2.2 Supplier Units

Table 6 provides the average resettlement per unit broken down further into the different Supplier Unit types.

Supplier Unit Type	Average Resettlement Per Unit
Independent Supplier	- € 174,502
Error Supplier	€ 222,924

Table 6 - Average Supplier Resettlement per Unit Type

Where resettlement for Supplier Units occurs the Error Supply Units (NI and ROI) are generally affected as the resettlement is primarily a redistribution of settlement between the Error Units and Independent Suppliers. This leads to the high average resettlement per Error Unit. This is compounded further as resettlement is only applied to one Error Unit in each jurisdiction.

As only one FCCR is currently defined under the Code it would appear unfair ,and may be a barrier to entry, if Independent Suppliers were required to post FCCR based on values incorporating the Error Supply Units.

For Supplier Units the average resettlement per Unit (excluding the Error Supply Units) was -€174,502. This would indicate that the FCCR is not required when looking only at the average resettlement per unit. However, further analysis, shown in Figure 10, looking at individual units average resettlement would indicate that reducing the present FCCR for Suppliers from €30,000 down to €20,000 would ensure on average that 81% of resettlement events would be covered by the FCCR.

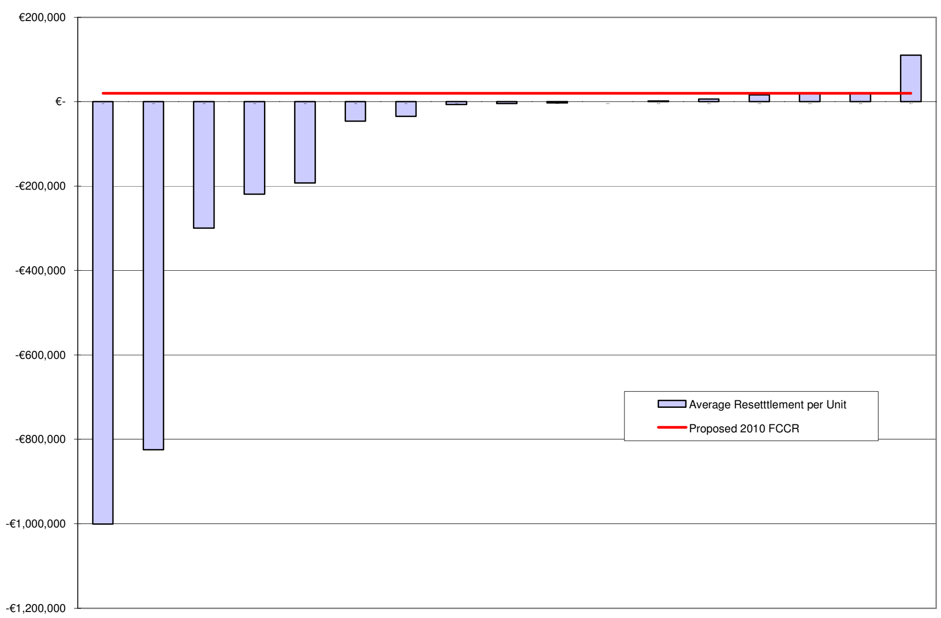

Figure 12 – Variance in Supplier Average Resettlement per Participant

3.6.3 Conclusions

Trying to determine a FCCR figure that is appropriate for all Generators or all Suppliers is extremely difficult given the nature of resettlement and the variation in resettlement amounts between even similar units. The current methodology to apply one FCCR to all Generators and one FCCR to all Suppliers may not be appropriate given the diverse range of resettlement amounts seen in the market.

Consideration should also be given to the treatment of Interconnector Units as Generators within the Code as under the current market conditions these units have been acting more like Suppliers than Generators.

Setting these observations aside, a balance between avoiding barriers to entry while ensuring the market default risk is mitigated as much as possible needs to be achieved.

3.6.4 Recommendation

Based on the analysis it is proposed that the Fixed Credit Requirement is maintained at €5,000 for Generator Units and reduced to €20,000 for Supplier Units in 2010.