Single Electricity Market

Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism

Decisions Paper and Response to Detailed Comments

February 2007

TABLE OF CONTENTS

1. INTRODUCTION

On 31 August 2006 the Commission for Energy Regulation and the Northern Ireland Authority for Energy Regulation (the Regulatory Authorities) published a consultation paper entitled *"Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism"*[1]. This paper considered a number of issues key to the derivation of the volume element of calculation of the Annual Capacity Payment Sum. The methodology for the determination of the price element of this calculation is currently the subject of a separate consultation titled "*Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism*"[2]. The paper set out the proposed methodology for the determination of the Capacity Requirement and discussed a number of options for addressing various aspects of the determination of the volume, in each case setting out the pros and cons and indicating the options which the Regulatory Authorities were minded to select.

Comments were invited on the proposals contained in the consultation document by 28 September 2006. Responses were received from eleven organisations and the non-confidential elements of these responses were published on the AIP website on 16 November 2006. This paper sets out the Regulatory Authorities' response to the comments received and presents the conclusions of the Regulatory Authorities' in the matters addressed by the consultation.

The main body of this paper focuses on the key issues and presents the Regulatory Authorities' conclusions in relation to the methodology for the determination of the Capacity Requirement, while more detailed responses to each of the comments received are provided in Appendix A.

The structure of this document is as follows:

Section 2 sets out the background to the development of the CPM and the consultation paper;

Section 3 considers the responses relating to the overall methodology and in particular the approaches to the treatment of identified surpluses and deficits;

[1] http://www.allislandproject.org/2006/AIP-SEM-111-06.pdf
[2] http://www.allislandproject.org/2006/AIP-SEM-124-06.pdf

Section 4 considers the responses relating to the adequacy standard to be employed in determining the Capacity Requirement; and

Section 5 addresses the responses on input data (demand forecast and generation availability).

In each of the above sections the key points raised in responses are summarised followed by the Regulatory Authorities considerations and conclusions. Responses to each of the points raised are provided in Appendix A.

2. BACKGROUND

On 15th July 2005 the Regulatory Authorities issued a paper titled "*Capacity Payment Mechanism and Reserve Charging High Level Decision paper*"[3] in which the Regulatory Authorities stipulated their intention to develop a fixed revenue capacity payment mechanism which would provide a degree of financial certainty to generators under the new market arrangements and a stable year-to-year pattern of capacity payments.

The principles outlined in the July 2005 paper were incorporated into the design of the CPM in the all-island Trading and Settlement Code (T&SC) and on 21st December 2005, the Regulatory Authorities published a draft version (version 0.10) of the proposed T&SC for the SEM, with comments invited by 20th January 2006. Subsequent to the publication of this document the Regulatory Authorities determined that a more detailed consideration of the comments received on the design of the CPM was required and on 3rd March 2006 the Regulatory Authorities issued a further consultation paper[4]. Following a further open forum discussion the Regulatory Authorities issued a Decision document in July 2006[5] in which they indicated the general support shown by respondents to the proposals for the determination of the Annual Capacity Payment Sum. On 31 August 2006 the Regulatory Authorities issued a detailed consultation into the proposed methodology for the determination of the Capacity Requirement[1] – the volume element of the calculation of the Annual Capacity Payment Sum. This paper sets out the decisions of the Regulatory Authorities in relation to the issues raised in this latter consultation and provides responses to the detailed comments received in response to the consultation.

[3] http://www.allislandproject.org/2006/AIP-SEM-53-05.pdf
[4] http://www.allislandproject.org/2006/AIP-SEM-15-06.pdf
[5] http://www.allislandproject.org/2006/AIP-SEM-95-06.pdf

3. Methodology for the Determination of the Capacity Requirement

3.1. Introduction and Outline of Proposals

The overall approach for the determination of the Capacity Requirement creates a database of generator availabilities accounting for both Scheduled Outage Durations (SOD) and Forced Outage Probabilities (FOP) over which the demand forecast is superimposed, enabling a Loss of Load Expectation (LOLE) to be derived for the year in question. This LOLE is compared with the applicable adequacy standard and adjustments are made in the event of a surplus or deficit in order to establish the quantity of capacity required to exactly meet the selected adequacy standard.

The first issue considered by this Decision document is the treatment of the identified surplus or deficit in order to arrive at the required capacity. Two methods were described in the consultation document with the Regulatory Authorities preferring an approach (referred to in the consultation as Method 1) which derived the surplus or deficit in terms of “perfect plant” and converted this into an equivalent quantity of “imperfect plant”, by reference to a Best New Entrant (BNE) in the event of a deficit or a reflection of the actual plant on the system in the event of a surplus.

3.2. Responses

Five respondents supported the approach preferred by the Regulatory Authorities as providing the most appropriate mechanism for determining any surplus or deficit, though two of these suggested that the choice of plant in the event of a deficit should reflect the “lumpiness” of generation – i.e. that an exact match against the requirement would be unlikely in reality and therefore any additions or subtractions of plant should reflect the likely size of units to be built or removed. Two respondents disagreed with the proposed approach, suggesting that it would depress the size of the determined requirement and that it would require judgement to be exercised in the choice of entry and exit plant. These respondents preferred Method 2 which derived the surplus or deficit by use of a scalar, effectively retaining the existing plant margin (in percentage terms) but scaled to meet the adequacy standard. One of these respondents argued that this method would self-adjust to reflect improvements in plant performance.

3.3. Consideration of Responses

Both Methods 1 and 2 have similar approaches in the event that a surplus is identified. Under these circumstances both methods would base the volume of plant to be removed on the characteristics of the existing plant. Method 2 would achieve this by scaling down the capacity in percentage terms to deliver a requirement which would meet the standard while Method 1 would select a reference plant which reflected the average unit size and characteristics (SOD and FOP) of the existing plant on the system. The two methods differ however when considering a deficit situation – Method 2 would again scale the capacity by reference to the existing plant on the system whereas Method 1 would use a BNE as the reference plant in order to derive a ration by which to increase the capacity to meet the standard.

Whilst it is acknowledged that Method 1 requires a choice to be made in the characteristics of the reference plant in the event that the system is in deficit, the Regulatory Authorities remain of the view that Method 2 would not be representative of new plant entering the market. Method 2 would effectively result in a reference plant with characteristics reflecting the existing plant which, particularly given the existing poor performance of plant in RoI, would be likely to be well below that which would be achieved by a new entrant. Whilst this may "self-correct" over time as more new entrants come into the market and availability improvements are experienced in existing plant, any such self-correction could take several years and in the interim would under represent the characteristics of new entrants. This would result in Method 2 systematically over-stating the requirement. The Regulatory Authorities therefore do not believe Method 2 to be appropriate for the establishment of the Capacity Requirement in the event that the system is in deficit and propose to adopt Method 1 for all circumstances since this is more likely to provide a reference plant with characteristics more closely reflecting a new entrant plant in the event of a deficit. The Regulatory Authorities do not accept that the adoption of Method 1 will depress the requirement as has been suggested. This is because while both methods adopt similar approaches in the event of a surplus, Method 2 is likely to over-state the requirement in the event of a deficit whereas Method 1 will provide a closer match to the new entrant. Thus rather than depress the requirement as suggested, Method 2 seeks to more accurately reflect the likely new entrant in the event of a deficit.

In the event of a deficit, the Regulatory Authorities will need to consider the unit size, SOD and FOP values for the reference plant. This was reflected in the consultation document which identified options of using a peaker, baseload or some average of BNE values for the reference plant. Some respondents suggested that the characteristics should be based on the type of plant likely to be built in response to the signals provided by the new market. Whilst this may be a valid approach the Regulatory Authorities consider that it is not possible to predict with certainty the type of plant which will be built in response to the market signals. Moreover such an approach could lead to potentially significant changes in the methodology year on year as opinions about the type of plant to be built change. In considering the characteristics to use to Regulatory Authorities have also considered the comments made regarding the reliability of new plant in its early stages of operation but do not believe it to be appropriate to reflect this within the sizing of the capacity pot as this would effectively build poor performance into the CPM, a matter which the Regulatory Authorities have previously stated they do not believe to be appropriate. Having considered the comments made, the Regulatory Authorities have decided that the characteristics of a BNE Peaking plant should be used for the reference plant in the event a deficit is identified. This is consistent with the use of the fixed costs of a BNE Peaker for assessing the price element of the determination of the Annual Capacity Payment Sum. Thus in the event of a deficit the Regulatory Authorities propose to use the characteristics identified for the BNE Peaker resulting from the consultation on BNE Peaker fixed costs.

On the issue of whether to reflect the “lumpiness” of generation in the assessment, the Regulatory Authorities are of the view that this is not appropriate. The objective is to establish a quantity of capacity required to just meet the defined adequacy standard since this reflects the need on the island. Trying to reflect the lumpiness of generation would be more likely to result in the Capacity Requirement being over-stated against the selected security standard. In the event of a deficit it would be necessary to add a plant which at least ensured the adequacy standard was met, suggesting that the requirement would be more likely to be over-stated. In the event of a surplus it would not be appropriate to deduct an amount greater than the identified surplus as this would result in a quantity lower than the capacity required to meet the standard and, therefore, it would suggest that again the requirement would be overstated.

The selected approach for addressing surplus and deficits (Method 1) uses a reference plant to establish a scalar to convert the identified surplus or deficit into an imperfect plant equivalent so as to scale the capacity to exactly meet the identified adequacy standard. The Regulatory Authorities therefore propose to adhere to this approach and not to reflect a step change in generation capacity within the Capacity Requirement which reflecting “lumpiness” would deliver.

4. ADEQUACY STANDARD AND APPROACH FOR THE CPM

4.1. Introduction and Outline of Proposals

In addressing the adequacy standard against which to determine the Capacity Requirement, the consultation document presented 5 approaches. In the consultation document, the Regulatory Authorities identified their preferred adequacy standard as that identified in Approach 2. In Approach 2, a single adequacy standard for the island of Ireland is utilised and the quantity of capacity required to just meet this target is determined on the basis of an unconstrained system. The use of a single standard reflects the basic principle of the SEM which seeks to implement a single market for the island of Ireland. The SEM design further identifies an energy price by reference to an unconstrained determination of the marginal price. The proposal to utilise a single adequacy standard for the derivation of the Capacity Requirement was considered by the Regulatory Authorities as being consistent with the unconstrained energy pricing mechanism and the overall design of the SEM.

To derive the single standard the Regulatory Authorities proposed to build upon the work conducted by the TSOs in comparing the existing adequacy standards for NI and RoI. This work identified that whilst the adequacy standards differed when expressed in common terms (hrs/year), the amount of unsupplied energy associated with each such standard when considered as a proportion of the regional demand was broadly equivalent. The Regulatory Authorities proposed to apply this measure of unsupplied energy to the entire island of Ireland and derive an adequacy standard which maintained this level of unsupplied energy. The TSOs undertook analysis on behalf of the Regulatory Authorities and identified that this method delivered a standard of 9.4 hours/year.

4.2. Responses

Four respondents were in favour of utilising a single adequacy standard derived in the way proposed by the Regulatory Authorities as a basis against which an all-island Capacity Requirement should be determined. One of these suggested that the value should be rounded to 9 hours/year so as not to infer a spurious level of accuracy in the determination of the Capacity Requirement while another wished to see a firm commitment to a timescale for the development of an appropriate all-island standard to be used for both adequacy reporting and the CPM.

Three respondents were concerned that utilising a single standard of 9.4 hours/year as proposed would result in a lowering of the level of supply security experienced by all customers on the island while another was concerned that it could artificially suppress CPM revenues, leading to overall generator revenues being inadequate with the potential consequences that the market could fail.

One suggested a single standard for the island should be adopted taken at the mid-point between the existing standards of 4.9 hours/year in NI and 8 hours/year in RoI and with an allowance made for the constraint across the North/South link. Two other respondents made similar suggestions, proposing that a single standard could be used provided an amount was added on to reflect the transmission constraint, likening it to the way generator payments are made whole in the energy market via separate constraint payments.

The need to recognise the existence of the transmission constraint and the effect it would have on the Capacity Requirement was also expressed by other respondents. Four respondents favoured Approach 1 as described in the consultation, which calculated separate capacity requirements for NI and RoI against their respective adequacy standards and then summed these to provide an all-island Capacity Requirement. It was suggested that such an approach would be more consistent with the assessment process being conducted by the TSOs and in recognising the limitation of the North/South link would more readily reflect the actual capacity required to meet the all-island demand.

No support was expressed for Approach 3 (reference to international standards) and one respondent recognised the difficulty identified in the consultation document by the Regulatory Authorities of arbitrarily selecting either the NI or RoI standard for the whole island (Approach 4). One respondent commented that while Approach 5 correctly identified that reducing the capacity on the island would increase the LOLE, on its own this would provide insufficient criteria for the selection of a standard.

4.3. Consideration of the Responses

The Regulatory Authorities remain of the view that it is necessary for the Annual Capacity Payment Sum to be determined on the basis of a single adequacy standard for the island of Ireland. This approach is consistent with the overall design of the SEM, reflecting the single market being implemented for the island. Deriving the annual sum on the basis of two standards would introduce an element of regional pricing which does not currently exist within the SEM design and which, in the view of the Regulatory Authorities, would not be appropriate for the SEM. However the Regulatory Authorities acknowledge the concerns expressed that the use of 9.4 hours/year could be seen as a lowering of the security standard for customers on the island. The Regulatory Authorities consider the derivation of 9.4 hours/year to be a reasonable approach – maintaining the quantity of un-served energy across the island and working backwards to derive a standard which retains this quantity does provide a standard which can be considered equivalent to the two existing standards for RoI and NI in terms of the actual number of MWhs lost. However it is clear that while the number of MWhs remains constant, the actual number of hours for which load is lost increases[6] and therefore this could be interpreted as a lowering of the security standard in the absence of further analysis.

The alternative approaches also have significant drawbacks. The consultation document identified the difficulties of establishing appropriate reference systems against which to draw a comparison to derive a standard (Approach 3) and adopting either one of the existing standards (Approach 4) would be an arbitrary choice without further analysis.

In considering the responses relating to this matter the Regulatory Authorities note that during early 2007 the TSOs will undertake the necessary work to develop an adequacy standard appropriate for the island of Ireland[7]. Given this and the comments made regarding the possibility that using a standard of 9.4 hours/year could be seen as a lowering of the standard, the Regulatory Authorities have concluded that it is not appropriate at this time for the Regulatory Authorities to define a methodology for the determination of a new adequacy standard for the island – this is a matter for the TSOs to consider in the work to be undertaken in early 2007. Since the work of the TSOs is due to complete at the end of March 2007 and the derivation of the Capacity Requirement for 2007 is not required until after March 2007, the Regulatory Authorities propose to utilise the standard developed by the TSOs in the determination of the Capacity Requirement for 2007 onwards.

In considering whether or not to reflect the constraint between the NI and RoI systems in the determination of the Capacity Requirement, it is necessary to remember that a key reason for the creation of the CPM was to smooth out the

[6] The reason for this is the size of the generating units compared to the overall demand decreases once NI and RoI are added together while the number of units increases, meaning that each event of lost load results in a smaller number of MWhs lost. Thus to maintain the same level of MWhs lost (EUE) it is necessary to increase the number of hours of loss.

[7] Current plans show this work to complete within the first half of 2007.

volatility in prices which would be experienced had the SEM been an all-island energy only market as originally proposed. In the absence of the CPM, prices would have been determined in the SEM on the basis of bids (which would have included an element of fixed costs) into a single unconstrained schedule for the island, deriving one system marginal price for each Trading Period for the entire island. In introducing the CPM the need for such fixed costs to be bid into the unconstrained schedule has been removed, however to maintain consistency with the energy only, all-island, unconstrained design, the Regulatory Authorities are of the view that it is necessary for the Annual Capacity Payment Sum to be determined on the same basis – i.e. all-island unconstrained. Therefore the Regulatory Authorities remain of the view that the determination of the Capacity Requirement should not reflect the constraint between NI and RoI as to do so would introduce an inconsistency between the energy and capacity markets.

5. INPUT DATA

5.1. Introduction

In this section the Regulatory Authorities considered a number of matters –

- Forecast Demand;
- Generation Capacity;
- Scheduled Outage Durations;
- Forced Outage Probabilities; and
- Treatment of Wind power.

In relation to demand, the Regulatory Authorities proposed that the all-island demand forecast be constructed by summing separate forecasts produced by the TSOs. These forecasts are produced by the TSOs as part of the adequacy assessment process where each TSO produces a number of forecasts to reflect different possible scenarios (depending on growth rates and other input parameters). The Regulatory Authorities proposed that while the TSOs would prepare the forecasts, the Regulatory Authorities would select the forecasts appropriate for the year in question for use in determining the Capacity Requirement.

The Regulatory Authorities proposed to determine generating unit capacity from Connection Agreement data as modified by any formal notification of changes to such data and suggested using the agreed scheduled outages developed through the Planning process for the Scheduled Outage Durations, subject to modification to exclude atypical events for a given year such as an FGD fit. The final element was the selection of appropriate Forced Outage Probabilities which the Regulatory Authorities proposed to base on those for NI plant as these figures reflect plant improvements following the introduction of the PPAs in NI and provide a basis to signal improvement requirements for all plant on the island.

The Regulatory Authorities also proposed to treat wind differently to other generator units in the determination of the Capacity Requirement, forecasting its output and subtracting this from the forecast demand rather than adding an estimate of wind availability to the generation side of the equation. The Regulatory Authorities further proposed to weight the contribution of wind when determining the final value of the Capacity Requirement by reference to a conventional plant equivalent – this approach was based on the capacity credit approach adopted by the TSOs when assessing generation adequacy.

The following sub-sections consider each of these matters in turn.

5.2. Demand Forecasting

5.2.1. Responses

There was a general acceptance that the TSOs should forecast their area demands and sum the resulting forecasts for the purposes of determining the Capacity Requirement, with some suggesting that the methodology employed should be common to both TSOs and in one case that such methodology should be consulted upon by the TSOs prior to utilisation. One respondent suggested that this forecast should use several years of historic data rather than a single year reference in order to average out temperature effects and avoid variations associated with the selected reference year. It was also suggested that in aggregating the two forecasts care would need to be taken regarding their respective errors as errors due to wind and weather (as well as other potential sources of error) could be strongly correlated. Another respondent suggested that the forecast should be based on stochastic estimates to avoid under representing “tail-event” demand spikes. It was also suggested that excluding non-market generation and its associated demand would under-estimate the requirement unless the outages of such generation (both planned and unplanned) were reflected in the determination.

The majority of respondents were not in favour of the Regulatory Authorities selecting the demand scenario to be used to determine the Capacity Requirement as this introduced an element of subjectivity and required the Regulatory Authorities to make judgements in an area not core to their function. Respondents generally preferred the choice to be left to the TSOs as independent organisations. One respondent suggested that the whole derivation of the Capacity Requirement should be undertaken by the TSOs in accordance with an agreed methodology and that the Regulatory Authorities’ involvement should be to scrutinise the process and approve the results to protect the interests of customers and other stakeholders.

5.2.2. Consideration of Responses

The support shown for the TSOs forecasting demand for the purposes of the CPM confirms the Regulatory Authorities view that there is little to be gained by seeking an external organisation to provide an all-island demand forecast and therefore the TSOs will be asked to provide a demand forecast for use in the CPM.

No objections were identified in the responses to the preparation of separate forecasts for NI and RoI as a result of the difference in underlying drivers for demand in NI and RoI. The Regulatory Authorities therefore will request the TSOs to prepare separate forecasts for NI and RoI as proposed and aggregate them into a single forecast for the island of Ireland. The Regulatory Authorities note the concern expressed by some respondents regarding the need to account for the demand forecast error and to ensure that such errors are treated correctly. This matter has been discussed with the TSOs who consider such issues to be more associated with short-term forecasts of the type used for scheduling rather than the longer-term forecast being produced for the Capacity Requirement. The TSOs confirmed that the approaches they adopt in forecasting demand seek to reduce the standard error as much as possible and to optimise the correlation coefficient in order to make the forecasts as accurate as possible.

The proposal by some respondents to establish a forecast on the basis of a number of historic years data rather than on the basis of a single reference year indicates that there is a need for clarification of the process. The TSOs establish the demand shape by reference to a single year. This is generally the most recent year as it most closely represents the likely shape of the year to be forecast. However in terms of forecasting the demand growth to be applied to this shape, the TSOs have some 30 years worth of data at their disposal. Thus the forecast uses many years historic data and not a single year as suggested.

Finally the Regulatory Authorities note the concerns expressed regarding their oversight of the demand forecast process and, in particular, the proposal that it will be the Regulatory Authorities who will select the demand forecasts from the range of forecasts produced by the TSOs for NI and RoI which are to be used for the purposes of determining the Capacity Requirement. This comment, together with the wider suggestion that the derivation of the Capacity Requirement should be undertaken entirely by the TSOs with the Regulatory Authorities role limited to approving the derived value, is addressed below.

Whilst the concerns regarding independence are noted the Regulatory Authorities do not consider the proposal to be inappropriate. Although the production of a forecast of demand against a set of scenarios is a role suited to the TSOs, the Regulatory Authorities do not believe it to be inappropriate for the final selection of scenarios to be used to be undertaken by the Regulatory Authorities since the purpose of the end product is to provide appropriate signals to participants, present and prospective, and the establishment of such signals is a core function of the Regulatory Authorities and not of the TSOs. In this regard the TSOs are to provide a forecast using their technical expertise to best advantage and the Regulatory Authorities expect the scenarios and forecasts to be presented by the TSOs in a way which makes clear the assumptions made and the uncertainties associated with the resultant forecasts. Based on this information the Regulatory Authorities will, in discussion with the TSOs, determine which such forecast is likely to provide the best representation for each jurisdiction for the year in question. The Regulatory Authorities believe this to be consistent with their function within the market arrangements given that the purpose of the forecast is to derive a market signal for capacity.

On the wider suggestion that the determination of the Capacity Requirement should be undertaken entirely by the TSOs with the Regulatory Authorities role limited to scrutinising the process and protecting customer and other stakeholder interests, the Regulatory Authorities believe that having consulted upon the methodology to be used to determine the Capacity Requirement and (in this Decision document) having provided conclusions as to that methodology, participants (both current and prospective) can derive assurance from this process.

The Regulatory Authorities therefore propose to ask the TSOs to prepare demand forecasts for each jurisdiction following their tried and tested approaches and to present the scenarios they develop and the resultant forecasts to the Regulatory Authorities. The Regulatory Authorities will then select appropriate forecasts for NI and RoI for use in determining the Capacity Requirement.

5.3. Generation Capacity

5.3.1. Responses

Three respondents supported the proposal to base unit capacities on the Connection Agreements as modified by formal changes, with some noting that it would be necessary to ensure that the stated capacities were on a comparable basis. However some respondents indicated that this would not provide a sound basis as it would be likely to over-state current plant capabilities. One respondent suggested that the capacities derived and utilised in the adequacy assessments processes undertaken by the TSOs would provide a suitable basis while two other respondents suggested the information should be sourced directly from the

Generators. Another noted that day/night and temperature effects which affect a unit capacity should be captured.

5.3.2. Consideration of Responses

The Regulatory Authorities note the concerns regarding the use of Connection Agreements as the source of the capacity for generating units. Owing to the different construction of some of the agreements the Regulatory Authorities accept that they may not provide the best source for the data and work would need to be undertaken to ensure that data obtained from such agreements provided consistency in the identified values for all plant across the island.

Using the data obtained by the TSOs for the adequacy assessment process may be a suitable alternative approach but having given further consideration to the matter the Regulatory Authorities favour an approach where the data is obtained from the generators themselves. The Regulatory Authorities therefore propose to write to each generator under the terms of the relevant generation license requesting the provision of unit capacities. The submitted data will then be subject to review by the TSOs prior to being used as an input to the determination of the Capacity Requirement. The Regulatory Authorities believe the opportunity for any gaming is reduced through this mechanism, although the mechanism itself for determining the Capacity Requirement provides a safeguard against gaming since any under-declaration of unit capacities will not necessarily lead to a higher Capacity Requirement because the effect will be a function of the difference between the SOD and FOP values of the reference plant and the unit(s) for which capacity has been under-declared.

5.4. Scheduled Outages

5.4.1. Responses

Five respondents did not believe it was appropriate to adjust for atypical events as this would under-estimate the capacity required for the given year. One respondent suggested that reflecting such atypical events would enable the actual capacity required for a year to be identified and would value capacity correctly. Furthermore this approach may influence closure decisions in any given year. Four respondents believed a historic view of outages would be more appropriate for the determination of the Capacity Requirement. This, it was suggested by one respondent, would avoid year on year swings in the capacity required and would remove the need to make adjustments for atypical events as proposed by the Regulatory Authorities.

One respondent believed using the adequacy assessment program CREEP to derive the scheduled outages would be appropriate while another suggested some form of simulation would provide an optimal approach. In contrast one respondent believed using such a scheduler would fail to recognise actual constraints on outage placement such as the availability of contractors. Two respondents favoured the approach proposed by the Regulatory Authorities as representing a good estimate of the likely outage schedules.

5.4.2. Consideration of Responses

The Regulatory Authorities agree with the respondents who suggested that the use of historic data would remove the atypical events which the Regulatory Authorities believe is necessary in order not to distort the year on year determination of the Capacity Requirement. The Regulatory Authorities believe it is necessary for the Capacity Requirement to reflect long-term trends such as plant closure and new build and do not consider it appropriate for the required capacity to swing year on year as a result of one-off events. The use of historic outage durations as suggested would address this matter without the need for specific intervention by the Regulatory Authorities. The length of period should not be so great as to significantly delay the data being influenced by improvements in outage performance – a matter which one respondent highlighted as being a key factor in the improvement of availability in NI plant following the introduction of the PPAs (see below). However the period should not be to short such that the identified values would likely be subject to influence of the one-off events which the Regulatory Authorities would prefer to exclude.

The Regulatory Authorities had proposed to use the agreed outage programme as the required input to CREEP, however the timing of the finalisation of the Outage Programme (end October each year) is too late to enable it to be utilised in the production of the Capacity Requirement – the Trading and Settlement Code requires the Annual Capacity Payment Sum to be published at least 4 months prior to the start of the relevant year, meaning the figure (and therefore the Capacity Requirement) would have to be determined in time to be published at the end of August. It would be possible to utilise the draft Outage Programme published towards the end of June each year, but discussion with the TSOs suggests that this programme tends to include pessimistic durations for a number of units owing to the incentive given to Generators to secure time slots in the year which cover the outage their plant actually needs without exact estimates of the required outage durations. The TSOs have therefore advised that the draft Outage Programme would not provide a good representation.

Another approach would be to utilise the outage programme collated as part of the GAR process. This process is run separately from the Outage Planning process so as to enable a reasonable view of the outage programme to be established on timescales which permit the GAR to be produced by October. However, if this programme were to be used for the determination of the Capacity Requirement it would take on a commercial aspect that to-date has not existed, opening the opportunity for the data to be gamed and devaluing the GAR process.

A further approach would be to provide CREEP with a set of outage durations and allow it to schedule the timing of the outages. This would mean providing CREEP with a gross forecast of demand (i.e. not net of Wind production) for the purposes of establishing the schedule – using the demand forecast net of Wind (which is used for the purposes of deriving the extent of surplus/deficit - see section 5.1 above) could result in distortions in the outage schedule. Furthermore certain plant would need to have their outages manually constrained – such plant are those entering or exiting the market where the periods of unavailability are treated as scheduled outages by CREEP, and hydro plant which could (because of their size) otherwise be scheduled to take outages in the Winter.

Of the options available the Regulatory Authorities believe that using outage durations constructed from historic data and scheduled by the adequacy assessment programme CREEP provides the best fit for the Capacity Requirement. In particular it addresses the concerns made by some respondents about the need to remove atypical events as previously proposed. The Regulatory Authorities propose that average outage durations will be used and where new plant are commissioned the average outage duration of plant in its class (e.g. CCGTs) will be applied. Given the matters referred to above the Regulatory Authorities believe a period of 5 years to be appropriate over which to determine the historic average durations. The TSOs will therefore be asked to identify the average outage durations and to utilise the adequacy programme CREEP to establish the outage schedule each year. In undertaking this approach the TSOs will be asked to make the necessary adjustments to the demand forecast and to apply the required constraints to the automatic scheduling for hydro plant and for plant entering and exiting the system.

5.5. Forced Outage Probabilities

5.5.1. Responses

None of the respondents agreed with the Regulatory Authorities preferred approach for identifying FOPs for the determination of the Capacity Requirement. Some respondents noted that extrapolating in the manner proposed would not reflect the age and plant type differences between NI and RoI and would therefore result in an inaccurate requirement. One respondent suggested that under-valuing the size of the Capacity Requirement in this way could lead to a supply security risk.

Some respondents argued that it was not reasonable to assume an improvement in RoI plant on a par with that achieved by NI plant following the introduction of the PPAs. It was suggested that the structure of the PPAs resulted in a more significant payment than would be likely to be delivered through the CPM and that this was a key factor in delivering the improved availability seen following their introduction. One respondent suggested that the improvement in availability seen following the introduction of the PPAs was more associated with reductions in the duration of scheduled outages than in a reduction of forced outages. Two other respondents noted that incentives already exist in RoI (as well as NI) to improve forced outage rates and that to postulate an immediate improvement in performance was not appropriate.

One respondent considered that it was inappropriate to request values of FOPs from Generators as this could make the parameter commercial, providing a gaming opportunity. In most cases respondents suggested that FOPs should be derived from historic data on a 1 to 5 year timescale, with two respondents stating that the derivation of the FOPs using historic data should be left to the TSOs.

5.5.2. Consideration of Responses

While the concerns expressed by respondents are noted, it remains the view of the Regulatory Authorities that it is essential that the CPM does not over value capacity. The Regulatory Authorities are of the view that reflecting the existing poor performance of plant, particularly in RoI, into the determination of the Capacity Requirement will effectively provide compensation to units which perform poorly.

One of the Objectives of the CPM is to provide an incentive for improvements in plant availability. The Regulatory Authorities believe that by establishing the

Capacity Requirement against a target FOP value, Generators will be provided with an incentive to improve their performance so as to capture more of the CPM payments. Using the performance improvement seen in NI since privatisation as a basis for establishing such a target is, in the view of the Regulatory Authorities, a reasonable approach.

In considering using NI plant as a benchmark, the Regulatory Authorities examined data pertaining to the early 1990s which showed how station performance improved significantly and very rapidly in the privatisation period. This performance has been maintained at a relatively high level since privatisation and in the view of the Regulatory Authorities demonstrates how Generators can respond given appropriate market signals.

The Regulatory Authorities note the comments that there are differences between the ages of plant in NI and RoI. However a review of performance data for NI plant shows that good availability performance can be achieved by the oldest of plant in NI. The Regulatory Authorities again note the significant improvement in performance achieved post privatisation in NI and which is still maintained today. The Regulatory Authorities also note the comments relating to the difference between NI and RoI plant in terms of fuel type. While the fuel diversity in RoI is undoubtedly greater than in NI it is not clear that this factor alone would account for the significant differences observed in FOPs between NI and RoI.

There are currently a mix of plant and ages in NI which, while not as diverse as in RoI, does provide a reasonable sample. That sample can be extended by taking performance over a period of time. The Regulatory Authorities have reviewed FOP data for NI plant for the last 5 years (2002 to 2006). This period includes plant which has been in operation for many years and plant which commenced operation during the period. The data shows a spread of performance over the period across the various stations. In assessing how to establish a target FOP value, the Regulatory Authorities concluded that figures relating to the availability of the Moyle Interconnector should not be included as it is not a Generator Unit and its inclusion would distort the data[8]. By the same reasoning the Regulatory Authorities concluded that the established FOP target should not be applied to the Moyle Interconnector when establishing the Capacity Requirement, but rather

[8] A FOP for the Moyle Interconnector is more akin to one which would apply to part of the Transmission System than a Generator Unit. As transmission capacity its physical availability is extremely high and therefore if it were to be included in the derivation of the average NI FOP, the value would be artificially decreased.

the forecast availability of the Moyle Interconnector should be based on its historic operation.

Having reviewed the data the Regulatory Authorities have calculated a weighted average FOP for NI plant over the past 5 years as 4.23%. It is this value which will be applied to all plant (excluding the Moyle Interconnector) in determining the Capacity Requirement each year.

5.6. Treatment of Wind

5.6.1. Responses

Four respondents generally supported the proposed treatment of wind generation in the derivation of the Capacity Requirement. One of these proposed that the capacity credit be determined based on the lowest percentage MWs observed from actual operation over the peak 30 hours in a year while another suggested its variability should be accounted for in the demand forecast too. Another respondent considered that the proposed approach would over state the contribution wind makes to security of supply given that flexible capacity would be required to compensate for the variability of wind and that the approach would not reflect this requirement into the CPM calculations. Another respondent concurred with this view and suggested a stochastic approach would be more appropriate.

5.6.2. Consideration of Responses

The Regulatory Authorities note the views expressed in relation to the treatment of wind in determining the Capacity Requirement and note the comments that this approach may over-value the contribution of wind. However the Regulatory Authorities believe that the proposed approach is consistent with decisions already taken in respect of wind generation, specifically in the approach to CPM payments for wind power which pay on the basis of generated electricity. The approach of removing wind generation from the stack of generation, predicting the likely generation of wind for the relevant year and netting this off the demand profile and then adding back a proportion of wind which reflects its rating when compared to a thermal power plant is, in the view of the Regulatory Authorities, appropriate and consistent with the payment mechanisms for wind under the CPM.

It could be argued that an alternative approach which used the estimated wind production to weight the contribution of wind in setting the annual sum would be more appropriate. This argument is based on the assumption that by weighting the wind on a capacity credit, wind will contribute less to the annual sum than it will take out in payments (assuming production is greater than the capacity credit). This may be true to a first approximation but the actual revenue received by Wind production will be a feature of when the wind blows, which may or may not coincide with the peak demand periods or tight margins which, in turn, will be the periods which attract the most payments under the CPM. In other words, while on average wind production may be greater than the associated capacity credit, it is the timing and intensity of wind production which will determine the actual level of payments received.

The capacity credit approach has been applied in the production of the adequacy assessment studies for a number of years and is generally accepted as a reasonable estimation of wind contribution. The Regulatory Authorities therefore propose to utilise this approach for the determination of the Capacity Requirement and, in principle, it should also inform the approach of the Regulatory Authorities to the payment for capacity of intermittent generation in the SEM. The treatment of Wind and other intermittent sources of energy in relation to capacity payments in the SEM is currently being reviewed by the Regulatory Authorities who intend to publish a consultation paper on the matters to be considered in due course. It should be noted that this review will not affect SEM implementation and recommendations for change, if any, resulting from the consultation process will not be implemented until after SEM Go-Live.

APPENDIX A – RESPONSE TO DETAILED COMMENTS

This Appendix sets out the comments received from respondents to the Consultation document and the responses from the Regulatory Authorities. The comments are grouped by subject matter for ease of consideration. Note that only points of contention are raised in this summary, comments made which agree with proposals or analysis set out in the consultation are not included.

Document Title:	**Methodology for the Determination of the Capacity Requirement for the CPM**
Document Ref Number:	AIP/SEM/04/06
Comments to be returned by:	28/09/2006
Comments returned to:	Peter Halligan (peter.halligan@ofreg.gov.ni)
Document Author:	John Parsonage

Respondee	**Heading / Comments**	**Response**
	Introduction & Summary	
ESB CS	The proposal to use the forced outage percentages of the NI plant as an average for all plant on the island does not take into account the plant characteristics such as generator type, age etc. and will not be an accurate reflection of the total system forced outage percentage.	The purpose of using average NI FOPs is to establish a level of Capacity Requirement which does not reward poor performance. Using the existing FOPs for RoI plant would result in a much higher requirement which, in the view of the Regulatory Authorities (RAs), would send an incorrect signal to the market as to the amount of capacity required by the island.

Airtricity	Squeezing the market revenue at the precise point where new peaking plant capacity would operate will effectively guarantee that the market will not attract the exact type of capacity it clearly needs. It is apparent that investment in a project which is only projected to break even will not be forthcoming, especially considering that the project depends on three separate and complicated revenue streams and employs a technology which has been traditionally hard to finance. The short sighted suppression of the capacity payment mechanism will result in the failure to attract new peaking capacity, possible inefficient operation of the system and market and undesirable interventions in the marketplace to try and secure the capacity - through competitive capacity tenders for example.	The RAs do not accept that the proposed methodology for the determination of the Capacity Requirement will suppress the CPM. The aim is to identify a requirement which is of an appropriate size for the island, which does not result in over-payments to generators but which does not fall short either. The aim is the meet the Objectives set out for the CPM. This means striking a balance between the various input data requirements (such as the forecast demand, adequacy standard and generator forced outage rates) which reasonably reflect the requirements. For example, the involvement of the RAs in selecting the appropriate demand forecast to be used is, in the view of the RAs, entirely consistent with the role of the RAs in promoting the market arrangements and will be undertaken in discussion with the TSOs so as to select the forecast which is most likely to represent the outturn demand for the selected year. The RAs have recognised the concerns regarding the perception of the lowering of the adequacy standard and have determined that it is more appropriate to await the outcome of the work being undertaken by the TSOs. Regarding FOPs the RAs believe it is essential that the current RoI FOPs are not utilised in setting the requirement as this would give a false impression of the capacity required to meet the adequacy standard. The RAs do not intend for poor performance to be built into the CPM arrangements. One of the Objectives of the CPM is to incentivise medium-term availability (i.e. maintenance of availability). It is the view of the RAs that building poor performance into the CPM will not provide an incentive for availability to improve in such poor performing plant and that a benchmark set of FOPs (based on average NI FOPs) will, taken together with the other elements of the CPM and the energy market, provide an incentive to improve availability.

VPE	VPE agree that a common capacity price across the island is not only correct but also central to the correct functioning of the SEM. VPE are comfortable with the figures of LOLE of 8hrs per year for the RoI and 4.9hrs per year for NI; these are figures that we recognise and we note that their application in the respective jurisdictions has resulted in reasonable security standards over the many years that they have been applied. VPE cannot understand however that when these two figures are combined on an all-island basis that the result is a LOLE of 9.4hrs per year. This is a more relaxed standard for security of supply and must mean that there is an increased risk of blackouts/brownouts on the island as a result. Surely there needs to be a wide and frank debate with both customers and governments across the island before the standards of electricity supply are to be reduced?	The figure of 9.4 hours/year arises because of the change in the number and relative sizes of the units compared to the demand – the number of units increases (the sum of NI and RoI) but relative to the demand the size of the units decreases. Thus the probability of significant loss of load decreases – i.e. the number of MWhs lost in any single event decreases. In order to maintain the ratio of expected unsupplied energy to the size of the system it is necessary to increase the number of hours of lost load. Notwithstanding this the RAs accept that moving to a standard of 9.4 hours/year based only on the analysis undertaken to-date could be perceived as a lowering of the security standard and since the TSOs are to undertake work in early 2007 to identify an all-island adequacy standard it is preferable to await the outcome of the TSOs work.
ESB PG	PG's primary comment relates to the method of determining the capacity requirement for the purposes of setting capacity payments. Our primary concern, is that by failing to realize the current realities of the physical transmission constraint, the proposed methodology for calculating the requirement and allocating payments could lead to insufficient incentives to invest on one or other side of the constraint since the level of capacity payments is set with reference to an All-Island LOLE calculation which does not recognize the constraint.	In establishing the design of the SEM it was determined that locational signals would not be reflected into the pricing mechanism. This was a cornerstone upon which the entire design of the SEM was based. The CPM forms a core part of the SEM design and therefore needs to be consistent with the non-locational design of the market arrangements. The RAs therefore do not believe it to be correct to reflect the existence of the N/S constraint in determining the CPM prices in the same way as the RAs do not believe CPM payments should account for the N/S constraint. If the constraint were to be reflected into the sizing of the CPM pot it would require payments to follow the same route, effectively establishing separate capacity sums and payment processes either side of a constraint. This would introduce significant inconsistencies with the overall design of the SEM which the RAs consider not to be appropriate.

NIE	NIE is concerned that the Regulatory Authorities' proposals for assessing the capacity requirement appear to be predicated on a reduction in the security of supply standard to which customers in Northern Ireland have been accustomed. In addition, NIE has a number of detailed concerns that other elements of the proposal are likely to understate the capacity requirement which will also expose customers in both jurisdictions to increased security of supply risk.	See above.
AES	Based on a LOLE analysis adopted by the TSOs, 4 x 100 MW peaking units contribute more to security of supply than one 400 MW base load unit. In recognition of this, AES recommends that the RAs consider weighting the distribution of Capacity Payments to reflect plant size.	This matter is not related to the determination of the Capacity Requirement but is a suggestion for a change in the way CPM payments are distributed. This is not, therefore, a matter under consideration at this time and is not addressed further in this document.

MOYLE	There is a fundamental inconsistency between the Annual Capacity Payment Sum being calculated in this way and the present draft of the Trading and Settlement Code (TSC). If this were not to be resolved, any part of the Moyle Interconnector capacity unused for trading by capacity holders and potentially available to the TSO after gate closure for adequacy purposes would not be paid the capacity payment. The relevant part of the Annual Capacity Payment Sum would then result in inflated capacity payments to other generators by virtue of an apparent generation capacity shortfall which does not exist in reality. This cannot be economically efficient.	The RAs do not accept that the proposed treatment of Moyle in the determination of the Capacity Requirement and in the distribution of CPM payments is inconsistent. In establishing the Capacity Requirement it is necessary to take a forward view of the possible capacity available to serve demand at all times in the year. Modifying this capacity for known events such as planned outages or for probable events such as forced outages is reasonable and correct in assessing the likely capacity to be available at any given time. The capacity of Moyle is no different in this regard and is assessed on the possible capacity which could be available to serve demand. The basis of payments under the CPM is to focus payments to the periods when capacity is at its most valuable and to distribute those payments to capacity which is available at the time. The timing here is taken at the day-ahead stage since the SEM is a day-ahead market. Capacity which can be offered to the market at a fixed price can be valued and can secure payments in the energy and CPM markets according to that value. Moyle is no different. However capacity which is not offered available at a price at that day-ahead stage (i.e. at gate closure) cannot be treated in the same way since its value cannot be established at the day-ahead stage. Moyle may offer additional capacity at a price set after gate closure but this has a different value to capacity offered at a fixed price before gate closure. The RAs do not considers these short-term considerations for Moyle to be inconsistent with the longer-term treatment of Moyle in setting the Capacity Requirement since Moyle could offer its entire capacity at a fixed price before gate closure.

SYNERGEN	In principle Synergen's believes that the CPM calculations should be purely mechanistic and accordingly there should be no judgement or discretion exercised in the determination of input data to the CPM unless absolutely vital. Accordingly, Synergen opposes any Regulatory Authorities discretion in the setting of key parameters, notably: ▪ forecast demand; ▪ forced outage rate assumptions; ▪ scheduled outages; and ▪ the selection of an appropriate candidate plant if the "perfect plant" approach is adopted. Such Regulatory Authorities' discretion is contrary to a mechanistic and objective determination of key CPM parameters.	The RAs recognise the concern regarding judgement being applied in the determination of the Capacity Requirement and are seeking to minimise any uncertainty in the process. Accordingly this Decision document concludes on matters such as the mechanisms to be used to establish FOPs and the candidate reference plant characteristics. In selecting the forecast demand the RAs make clear the purpose is to select the forecast which is most likely to reflect outturn demand and that this process will be conducted in discussion with the TSOs. The RAs are satisfied that this minimises the uncertainty associated with the judgements to be applied.
	Harmonisation of Generation Adequacy Assessment and Reporting	

AES	The paper appears to say that the TSOs prefer separate adequacy standards and assessments for each jurisdiction (because of their assessments of ATC on the N-S interconnector). Consistent with the SEM high level principles and the approach adopted for determining the system marginal price, AES considers that standards should be set and adequacy assessed on an all-island basis from the go live date. Together with the joint Government decision on interconnector re-enforcement, this would help to signal the absence of any bias in regard to the location of new power plants. The existing ATC on the N-S interconnector appears to be very conservative compared to the physical capability. Very little information is presently published on the methodology and assumptions used for determining this ATC. In the interests of promoting the high level principles of the SEM, AES recommends that the RAs consult on the methodology and assumptions used by the TSOs to determine inter regional capacity reliance. The TSOs should publish annually up to 10-year forecasts of Capacity Required to promote efficient new entry. Firm and provisional Scheduled Outages agreed with TSOs, in accordance with the Grid Codes, should also be published annually.	The majority of this comment relates to the adequacy assessment process and the publication of the associated results which the TSOs are required by licence to undertake. A further element relates to Grid Code matters relating to the co-ordination of planned outages between generators and the TSOs. Consequently the majority of this comment does not relate specifically to the determination of the Capacity Requirement. However the RAs recognise the potential value in seeking to provide forward forecasts of future Capacity Requirements and will consider the feasibility of this, recognising that any such forecast will inevitably be subject to changes as further information on demand and plant capacities becomes available closer to the calculation of the actual requirement figures.
ESBCS	The need for continuation of two separate generation adequacy standards due to the North-South Interconnector constraint is understandable but ESBCS would like to see a commitment set out to harmonize the standard under a set time-frame i.e. up to the commissioning of the second North-South Interconnector. The use of the constraint on the all-island system as a reason for keeping the two standards could effectively be used wherever there was a constraint on the system. Of course this would end up with locational pricing which goes against the principle of a Single Electricity Market.	The TSOs view is that the only constraint which gives rise to the need for separate standards is that across the N/S link. This is the only constraint of sufficient significance and longevity to give rise to separate LOLEs. In terms of committing to a single adequacy standard the TSO Harmonisation Plan identifies that work on a single adequacy standard for the island of Ireland will complete by the start of the second quarter in 2007.

MOYLE	In this section on harmonisation of generation adequacy assessment one issue is notable by its absence, particularly as the existing difference in approach between the two regions was explicitly commented on in a forerunner to the present consultation paper. Paper AIP-SEM-15-06 of March 2006 (CPM and Associated Input Parameters) pointed out that, under the existing RoI GAR analysis, the central studies do not place any dependence on the capacity of the interconnector with Northern Ireland. On the other hand, that paper also commented that the capacity contribution of the Moyle Interconnector has to date been taken into account in the generation adequacy assessments for NI. The validity of that assessment has been confirmed in the service experience of the last few years by the number of occasions on which the Moyle Interconnector has actually been called on to maintain adequate generation capacity on the NI system.	The consultation paper makes clear that in harmonising the generation adequacy assessment processes the TSOs have agreed to incorporate a formal capacity reliance between the two systems in the assessment process. Thus RoI will place a formal reliance on capacity from NI in future adequacy assessments (and vice versa).
NIE	We note that the TSOs' proposal is to apply a consistent methodology in each jurisdiction whilst maintaining the existing generation security standards, but to introduce a credit for inter-regional capacity reliance. This of itself will have the practical effect that customers will see a deterioration in actual security of supply. The assessment of the capacity requirement should take account of the forecast standard error (which is not mentioned in the description) and the demand forecasts should be based on historic demands averaged over several years (rather than on actual demand in an individual year as the RAs have proposed).	Under the harmonised generation adequacy assessment process, the TSOs will be reflecting into the process the practices which have been undertaken over the last few years. Until now each jurisdiction has been able to rely on the other in the event of a circumstance of shortfall in capacity. This reliance has been in operation for a number of years but has not previously been reflected into the adequacy assessment process. The inclusion into the process means the TSOs are simply allowing the assessment to reflect reality.
	Methodology for the determination of the capacity requirement	

ESB PG	If we start from a position of disequilibrium, whereby there is insufficient capacity on one side of the constraint, but excess (constrained-off) capacity on the other side of the constraint, under Approach 2 there may be insufficient financial incentive to invest in plant on the short side of the constraint. The lack of appropriate incentive occurs because excess capacity on one side of the constraint could depress the All-Island capacity payment per unit of capacity to a level below the BNE new entry cost. We understand that Approach 2 is consistent with the design philosophy of the market, and the RAs desire to avoid locational pricing, but we are concerned that the proposals as currently designed (i.e. ignoring transmission constraints) could jeopardise system security. It is important that there are mechanisms to ensure that there is sufficient (but not excessive) capacity on both sides of the constraint, and that the RAs should not gamble on the hope that new pool rents will compensate for capacity payments which do not cover BNE capacity costs.	As stated earlier, factoring the constraint into the determination of the Capacity Requirement while leaving it out of the payment process would introduce a significant inconsistency into the CPM. If the constraint is to be recognised it would be necessary to move to regional payments for the CPM – creating a location based market in capacity which would be inconsistent with the overall design of the SEM. The RAs have recognised the system security issue raised by Respondents and have determined that the standard to be used should be that resulting from the work to be undertaken by the TSOs in the early part of 2007.
VPE	Method 1 and 2 – and the treatment of surplus/deficit VPE suggest that what ever method is adopted that it should consider the possible types of new entrant plant where there is a deficit. As the new entrant is likely to be a BNE peaker or a BNE base load plant a statistical calculation of the characteristics (ie SOD and FOP characteristics) could be taken as being representative of the reference plant, based on the likely relative probability of the introduction of one type of plant over the other. The system requires additional generation capacity to cover granularity resulting from the large size of generation plant relative to the size of the system, as meeting the exact adequacy standard is unlikely due to the minimum size of plant. For example if the system is determined to be in deficit by 1MW the additional capacity will only be met by a build of an additional unit (typically a BNE base load or BNE peaking plant) which will greatly exceed that 1MW. VP&E therefore suggest that an additional number of MWs should be added to the capacity required to deliver the adequacy standard, say an addition of half the number of MWs of the choice of reference plant from above.	Predicting the type of plant to be built in response to the market signals cannot be done with certainty. The RAs preference is to use the characteristics of a BNE Peaking Plant in the event of a deficit as this is consistent with using BNE fixed costs as a basis for setting the CPM pot. The RAs do not believe reflecting the “lumpiness” of generation into the requirement calculation to be correct since it will, more often than not, result in more capacity being identified as being required than is necessary to exactly meet the standard. This is because whether the system is in deficit or surplus, it would be necessary to add or subtract capacity so as to ensure the standard was at least met – i.e. it would not be acceptable to under size the requirement. The methodology to be employed uses the reference plant (in both deficit and surplus situations) to define a scalar between perfect and imperfect plant so as to identify the capacity required to just meet the standard. This is the approach the RAs intend to adopt and, therefore, the lumpiness will not be reflected.

Airtricity	The regulatory authorities should clarify if the generation adequacy assessments for the system and the CPM will be conducted by Monte Carlo simulation or calculated by exact probability. The exact probability approach is preferable, but the possible difficulties in computation time are acknowledged.	The TSOs have confirmed that the calculation will be carried out by exact probability.
NIE	The proposal to exclude the capacity of non-participating generation and the associated demand from the calculation of the capacity requirement will understate the amount of capacity needed for equilibrium and will put security of supply at risk for all customers. NIE considers the adoption of the “perfect plant approach” (method 1) for dealing with Surpluses and Deficits will further impact on security of supply by depressing the capacity needed. NIE considers that the “Scaling” approach (method 2) is the better approach to adopt and it has the benefit that if availability improves on a sustainable basis, this method will self-adjust to reflect that improvement without the risk of over-statement that exists under the perfect plant approach.	The RAs do not concur with this point. Non-market generation does not, by definition, receive any payment under the CPM. If the CPM Capacity Requirement were to include such generation it would clearly overstate the requirement. The Capacity Requirement is only being determined so as to enable the size of the Annual Capacity Payment Sum to be determined. It is therefore correct that this amount should be determined by reference to that capacity which is eligible to receive CPM payments. The RAs main concern with Method 2 is that it uses existing plant characteristics to size both surpluses and deficits. In the case of a surplus this is a reasonable approach (a similar approach is also adopted in Method 1 under such circumstances) however in the event of a deficit, any new entrant will almost certainly have better characteristics than an average of the characteristics of existing plant. Consequently the RAs do not support Method 2.

MOYLE	Given that the existing generation adequacy assessment for NI includes the Moyle Interconnector at 450MW and 98-99% availability, we assume that the TSOs' 2007 adequacy assessment will be on the same basis for the reasons outlined above. As the present consultation paper states that the principal features of the methodology for the determination of the CPM Capacity Requirement will be the same as for the harmonised adequacy assessment and as the paper makes no mention whatsoever of external interconnectors, we conclude that the Moyle Interconnector will be included in the CPM Capacity Requirement in the same way. The Capacity Requirement will then (other things being equal) bear the same relationship to demand as does total generation capacity in the present adequacy assessment demand and the Annual Capacity Payment Sum will in this respect be correctly set. Under the TSC, it appears that capacity payments will only be made in respect of net interconnector trading flows. In practice, the balance of Moyle's 450MW capacity, backed by the 70TW of installed generation capacity on the GB system, would potentially be available to the TSO between gate closure and real time to provide the necessary generation capacity as at present. However, no capacity payment would be made in respect of that capacity balance. It appears that the relevant part of the Annual Capacity Payment Sum would then be paid to other generators, which cannot be right or economically efficient since it would be paying inflated capacity payments by virtue of an apparent generation capacity shortfall which does not exist in reality.	As stated above it is possible for Moyle to offer its capacity to the day-ahead market before gate closure at a fixed price. If Moyle chooses not to do this then it will receive CPM payments in relation to that capacity that it is prepared to offer (at a fixed price) by gate closure in the same way as other generators and it will forgo CPM payments on the remaining capacity. In deciding what capacity to offer at the day-ahead stage it is assumed that Moyle will take this change in revenue stream into account.
	Adequacy standards and the CPM	

BGE	The individual system operators should separately assess generation adequacy in North and South. While the inter-connector offers some mutual support, it cannot be guaranteed at the peak. When calculating an all-island capacity requirement (by comparing total generation and demand), inter-connector constraints should not be ignored. We do not agree with the argument that for consistency the capacity margin should be considered on an unconstrained basis as there does not appear to be any capacity payments being made in respect of constraints and the (energy) payments made go to real plant operating in a real system, which includes constraints.	Assessing adequacy on the basis suggested would be to ignore the benefit of the interconnected systems and would retain costs at an un-necessarily higher level. See above.

VPE	VP&E would like to see the proposed methodology for calculating the MWs of generation capacity required based on the parameters as part of the consultation. The approaches outlined in Section 5 seem to have confused the methodology for determining the MW of generation required with the setting of a security standard in a LOLE in hours. In fact if the generation capacity adequacy standard is defined in terms of LOLE in hours/year then the actual MWs of generation required should be calculated from this determination. The main argument for having a higher adequacy standard in a smaller system surrounds the high standard deviation that can be seen in the standard normal curve as a consequence of having fewer, larger units in a smaller system. Thus although the mean LOLE may be the same as that chosen for a much larger system with many units there is a larger probability of having a large number of LOLH on a smaller system in a single year. This can be catered for either by allowing for an additional number of MWs, or by increasing the security standard by reducing the LOLE accordingly. VP&E therefore consider that a LOLE of 4.9 hours/year may be required for NI whilst the N/S Interconnector represents a significant constraint. This will necessarily increase the generation adequacy standard for the all island system. Approach 1 looks like an attempt to describe the current situation where in ROI the capacity requirement is derived from an adequacy standard of 8 hours/year LOLE and in NI the capacity requirement is derived from an adequacy standard of 70 days in 100 years LOLE. It	The RAs do not consider taking an arbitrary value between 4.9 and 8 hours/year to be appropriate given that the concern relates to the perception that the standard is being lowered. For the same reason the RAs have decided not to pursue using 9.4 hours/year as originally proposed. Instead the standard resulting from the work to be undertaken by the TSOs in early 2007 will be utilised. The RAs do not support the use of Approach 1 because of the creation of a locational element which would need to be reflected on through the rest of the CPM (i.e. into payment distribution) which would create a significant inconsistency between the energy and capacity markets (see earlier).

	is correctly identified that the introduction of a locational element into the Capacity mechanism would create a distortion in the SEM. This method appear more consistent with current practise used in calculating current security standards. Given that this approach has resulted in adequate security of supply to date it would not be prudent for the regulatory authorities to change from this approach unless the other approaches are demonstrably better. We fail to see substantial benefits from the other 4 approaches set out and thus suggest that approach 1 is preferable. Approach 2 fails to acknowledge that a LOLE of 9.4 hours/year does represent a lowering of the generation adequacy standard which is not "consistent with the existing security of supply seen by customers across the island of Ireland" as stated in the consultation paper. An increase from 8 to 9.4 hours/year LOLE represents a lowering of the generation adequacy standard. Whilst approach 3 takes cognisance of experience elsewhere it confuses the methodology of determining the MW of generation capacity with the determination of the adequacy standard. Approach 4 takes note of the 2 different adequacy standards and correctly identifies the difficulty with arbitrarily choosing one or the other for use on an all island basis. VP&E suggest that an acceptable compromise might be to use a value part way between the two of say 6 hours/year LOLE. Approach 5 identifies that as capacity is removed from the system the LOLE increases and savings are made in having a requirement for less generating capacity. This consideration is the case in whichever adequacy standard is chosen, but does not of itself provide sufficient criteria or a methodology to inform how the adequacy standard should be set in a LOLE in hours/year.	

	VP&E suggestion Given the different security standards and prior to the removal of the constraint on the N/S Interconnector a compromise will be necessary to determine the MWs of generation capacity required in total for the all island in the SEM. VP&E suggest the following two options (which are necessarily compromises) to deal with this difficulty: 1. Apply the different adequacy standards (LOLE of 4.9 hrs/year in NI and 8hrs/year in ROI) to the respective jurisdictions, calculate the respective MWs generation capacity in each jurisdiction and add these together to determine the all island MW capacity requirement. 2. Use an adequacy standard part way between the two of say 6 hours/year LOLE and calculate the MWs of generation capacity required on an all island basis ignoring the constraint. Option 1 has the advantage that it represents the actual generation capacity required to deliver the respective adequacy standards whilst respecting the constraint. Option 2 doesn't respect the constraint and is likely to underestimate the generation capacity required but it removes the locational aspect of determining the generation adequacy. One solution might be to employ Option 2 with an uplift to compensate for the fact that it doesn't respect the constraint.	
SYNERGEN	AIP/SEM/111/06 describes how there will be reporting based on separate standards assessed under a common methodology given the high level of interjurisdictional constraints envisaged. Unlike the present security assessments there will be an assumed level of support for each of the NI and RoI systems based on assumptions on capacity availability across the existing North / South interconnect. This reporting is inconsistent with the CPM calculations of a single SEM standard, in essence public reporting is against two separate different standards. The nature of the North / South transmission constraint means that the total generation adequacy required is greater than if the SEM was not significantly constrained. The public reporting should be consistent with the CPM calculation – essentially customers should be told what they are paying for.	It is clear that customers will be paying (in the context here) against the requirement established under the CPM, not against the adequacy assessment report produced by the TSOs since the TSO reports are not associated with payments. The TSO reports will provide indications of surpluses or deficits in their respective jurisdictions given operational considerations. This may be of use to investors wishing to optimise usage of existing or new capacity. The CPM will provide the commercial signal.

NIE	We would be concerned if the requirement determined for the CPM was on a different basis to how the TSOs propose to assess generation adequacy. This will have the effect of sending mixed signals to potential investors and is likely to result in a lower capacity requirement for the CPM than the TSOs indicate is required. The effect could be an increased risk to security of supply for customers and general confusion for potential participants / investors. The alternative is to adopt a single all-island approach but add back capacity to represent the limitation imposed by the interconnector capacity. It would be prudent to do the calculations, with both separate and overall standards (adjusted for interconnector reliance), to check that they are consistent. However, the discussion above (in Section 2.1) suggests that further work on the standard may be required. A single standard should be considered in addition to the use of Approach 1, probably using elements of all of Approaches 2-5, but care must be taken that the definition of both the individual NI and RoI standards and any overall standard is appropriate for the calculations being made.	See earlier comments.
	Input Data	

ESB PG	*Input data - Forecasting demand* The document states that the RAs will use the “forecasts that they believe are the most likely to reflect the demand in the relevant year in each jurisdiction”, likely to equate to a central case estimate. The approach of using a central case estimate of demand, as opposed to stochastic estimates of demand, is that the model will under-represent the probability of “tail-event” demand spikes. As a result, the report LOLE will, so will under-estimate true LOLE/Expected Unserved Energy, since genuine loss of load events can be expected to be correlated with demand spikes as well as high coincidence of forced outages. Ideally, the TSOs would use stochastic demand scenarios as well as stochastic forced outage scenarios. *Input data- Generation effective capacity assumptions* We are of the view that estimates of generation capacity should suggest that this should be sourced direct from generators, as per the current RoI practice. The RAs preferred approach of basing the estimate on Connections Agreements (as modified by formal notification) may fail to reflect all appropriate degradations in capacity, and over-estimate effective capacity.	*Demand Forecasting* In forecasting the forward demand the TSOs use all relevant available data over a 30 year period to estimate the demand growth. This includes world trade trends (a factor which impacts RoI more than NI) as well as domestic growth trends. The aim is to develop a forecast which minimises the error and proves the best forecast. The development of separate forecasts for RoI and NI is necessary as the underlying drivers for the two jurisdictions differ, but the aim is to prepare an overall forecast for the island which is as accurate as possible. In discussion with the TSOs, the RAs will determine which forecast to be used for each jurisdiction for determining the Capacity Requirement and will aim to select the forecast which best represents the likely demand. The RAs believe this to be a reasonable and practical approach. *Generator Unit Capacity* As set out in the main text the intention is to write to the Generators to provide the required data under the relevant Licence condition and that the provided data will then be subject to review by the TSOs.

	Input data - Forced outage probabilities We do not think that it is appropriate to postulate an immediate improvement in RoI forced outage rates to NI levels, for the following reasons. Firstly, PG already works under a regime with incentives to improve forced outage rates, so the paper over represents the implementation of the SEM as a step change in incentives on PG to reduce forced outages. Secondly, in our view, sinking investment in aged plant (to a level not justified by market returns) would not necessarily be an economically effective way to bring forth new capacity, and should not be the assumption underpinning modelling of requirements. *Input data - Wind* The RAs propose to model wind as a reduction in load, using capacity credit approach modified to reflect wind's net contribution to the capacity requirement. In principle we believe that wind should also be modelled stochastically, and that capacity credit approach will lead to understatement of LOLE, as there are likely to be tail risk events of low/no wind, combined with high demand which are not reflected in the capacity credit approach. As wind becomes more material in terms of its contribution to All-Island capacity, the capacity credit approach should be reviewed.	*Forced Outage Probabilities* The Objectives set out for the CPM include the requirement to "encourage the construction and maintenance of available capacity". The RAs do not believe establishing a CPM pot on the basis of poor plant performance to be consistent with this objective since it will lead to an inflated pot. Therefore an alternative approach is required and in the view of the RAs it is reasonable to establish FOPs on the basis of a review of those achieved in NI as these were in response to the incentives placed upon NI plant by the introduction of Availability payments in the PPAs. The RAs could have chosen to set the FOPs on the basis of the best performing plant in order to maximise the incentive for availability improvement, however the RAs believe an average of the values for these plant would be a more reasonable approach. The RAs note that the CPM will effectively replace the existing scheme for improvement referred to by the Respondent and the suggestion by the Respondent that improving the availability of existing plant may not be economically efficient. The performance of RoI plant has historically been poor. Review of recent GARs shows that forecasts of performance have been consistently over-estimated by Generators in RoI. This document also shows that while Availability in the five years from 2001 to 2005 (inclusive) has been as low as around 77%, it has been 10% higher than this value too and therefore there is scope for achievable improvement. The RAs do not therefore consider setting the CPM Capacity Requirement on the basis of average NI FOP values to be unreasonable.

		Wind The approach for modelling Wind is, in the view of the TSOs, the best way to treat the output from wind generation when assessing generation adequacy (and is the approach taken by the harmonised Adequacy Assessment process on which the determination of the Capacity Requirement is based). The use of a capacity credit approach is a recognised method, however as the depth of wind penetration increases it may be necessary to keep this approach under review.
ESBI	*Input data - Forecast Demand* Given the differences between the two jurisdictions, and the experience and expertise of the two TSOs, the preferred approach of summing their separate forecasts seems to be practical. We would prefer to see an ultimate land usage forecast than one based on actual demand at existing substations and perhaps this could be considered in future. ESBI recognises the oversight role of the RAs in such matters but is extremely concerned at the proposal that they would "*select the forecasts which they believe are most likely to reflect the demand in the relevant year in each jurisdiction*". This is not the function of a regulator but of an independent system operator, which EirGrid already is and which SONi is on the way to becoming. These are the entities with the resources and capability to develop demand forecasts and the paper does not provide any rationale for them to be second-guessed by another entity. For the RAs to intervene in some way in the demand forecasting process will increase the perception of regulatory risk in the SEM and, since the RAS will have to acquire the relevant expertise, is likely to increase the cost to electricity customers of regulation.	*Forecast Demand* The RAs consider that the establishment of a market signal for the value of capacity is a function within the scope of their duties and do not therefore consider their role in the establishment of the demand forecast to be used for the purposes of setting the Capacity Requirement to be inappropriate. The TSOs will be asked to produce a set of demand forecasts and the RAs, in discussion with the TSOs, will identify the forecast which is most likely to reflect the demand in the year in question. The RAs are satisfied that this is a reasonable duty for them and do not believe this will increase the perception of regulatory risk as suggested.

	Input data - Capacity ESBI agrees with using the connection agreements for generator capacity but notes that these agreements will have to state capacity consistently. In NI, for example, Coolkeeragh's CCGT connection agreement is in MW but the other generator's connections are denominated in MVA, which can be open to interpretation depending on what power factor is assumed. *Input data – Forced Outage Probabilities* We do not, however, agree with the RAs' preferred approach (option 3) of applying NI rates to all generators. EirGrid's estimate of 100MW impact on GAR for each 1% change in FOP is mentioned but without knowing thedifference between RoI and NI FOP rates we have no context for assessing this option. NI generator availability isnot published so respondents to this consultation are not in a position to compare the impact of applying the NI figures in both jurisdictions with using RoI availability information published by EirGrid. To base CPM on a notional capacity requirement which is lower than the TSO's published GAR will send mixed signals to the market and to new entrants, and increase the perception of regulatory risk.	*Capacity* See above. *Forced Outage Probabilities* See above.
	ESBI agrees with adopting the approach described as option 2, at least initially, of using historical availability and thinks that the answer lies in the statement about NI generators that *"Overall availability levels in NI improved significantly following the introduction of the Power Purchase Agreements (PPAs) in the early 1990s, which provided generators with an explicit incentive to improve availability."* Rather than prejudging the RoI generators and assuming that their availability will not respond to incentives, our view is that the RAs should adopt a historical availability approach, ie a CPM based on GAR, and only review this if RoI generation availability does not respond by improving.	

BGE	*Input data - Forecast Demand* Demand planning should be based on peak winter demand requirements (e.g. a 1 in 25 winter); There should be a regular assessment on TSO forecast accuracy and adjustments required if there is any observed bias to under or over estimate demand. *Input data – Capacity* Basing capacity values on connection agreement values will have the effect of overstating capacity. Real life temperature and degradation effects should be considered when establishing capacity for each unit. Historical day/night monthly average should be applied as a minimum to obtain a reasonable capacity value. *Input data – Scheduled outages* The proposed approach seems to ignore the potential for prolonged outages at peak and the risk to supplies that this entails. There is usually a higher probability for a unit to be out at a particular point in time. A simulation approach may provide a more robust analysis if this is reflected in the disappearance ratios. More discussion is required on this issue.	*Forecast Demand* The forecast process for NI used to consider peak demand only however in harmonizing the adequacy assessment process the TSOs concluded that forecasting demand for a 52 week year provided a better solution and a more accurate estimate of adequacy. The Capacity Requirement therefore is to adopt this approach. *Capacity* See above *Scheduled outages* The RAs original proposal had been to utilize the Outage Programme and modify it to remove atypical events in order not induce year to year changes in the level of the requirement which would not represent the long-term requirement. However, the RAs have determined that using historic outage durations, combined with the use of CREEP to schedule such outages in the relevant year, provides the best solution given the objectives of the CPM.

	Input data – Forced Outage Probabilities We do not believe it is appropriate to apply historic NI forced outage rates to ROI plant. ROI plant was designed, built and operated to different criteria than the NI plant. For example, the ROI market was bigger and additional spend to maintain the system for security of supply was less essential. The ROI plant makes up the majority of SEM plant and the historical rates should be applied in all cases as in order to market any fair assessment. The CPM should be an incentive for all plant, so their availability should improve over the medium term. We would propose a review after 5 years of operating history of the SEM. *Input data - Wind* Wind is highly volatile and a substantial discount to installed capacity would seem appropriate to reflect this. We would suggest taking the lowest % operating MW observed in any hour over the peak 30 hours (typically taken as the minimum running assumed for the most expensive but flexible plant on the system). If system demand forecasts are adjusted to account for embedded generation, their contribution should be adjusted for assumed forced and maintenance outages.	*Forced Outage Probabilities* See above. *Wind* The RAs agree that the contribution of wind is highly volatile however the proposal to use a capacity rating as described is considered a reasonable mechanism as this captures this variability. Valuing wind on the basis of the lowest contribution over the peak 30 hours as suggested could give rise to volatile estimates year on year. Regarding embedded generation, either they are removed from the stack and the demand is adjusted or they are retained and have appropriate SOD and FOP values. Mixing these approaches, as appears to be suggested here, would incorrectly account for the contribution of these generators.

VPE	Input data – Scheduled Outages It is critical that outage scheduling is done on a fair and transparent basis, given the commercial implications for market participants. Whilst there is a constraint on the North/South Interconnector it will be necessary to schedule outages on a jurisdictional basis. The TSOs should adopt a common agreed approach to outage scheduling in both jurisdictions up until the North/South Interconnector constraint has been removed, after which a single outage schedule can be produced on an all island basis. Forced Outage Probabilities The determination of each unit's FOP is fundamental to the determination of not only the MWs of generation capacity requirement for the purposes of CPM under the SEM but also for operational considerations in having adequate generation to meet the adequacy standard. The danger for the System Operators is that over-estimating the availability of plant would result in a generation capacity shortage and a resultant high LOLH on the system. VP&E question the proposed application of the historic availability values for generators in NI to all generation plant on the island of Ireland. Is the rationale for the application of the higher availability generators in NI to poorer availability plant in ROI sound? The basis of this	*Scheduled Outages* The RAs remain of the view that scheduling of outages is a matter for the Grid Code, as the involvement of the TSOs in outage planning is a matter not confined to the CPM. Forced Outage Probabilities See above. In addition it should be noted that under the SEM a baseload generator will receive SMP as stated and that this will, for a baseload and any other in-merit plant, provide a contribution to its fixed costs. Therefore a comparison of the PPAs and the SEM needs to consider the whole payment stream and should not seek to equate the CPM directly against the Availability payments under the PPAs. The RAs are of the view that it is therefore reasonable to set the CPM pot by reference to the improved availability of NI plant so as not to double pay generators – i.e. paying for fixed costs in the SMP and then overpaying further fixed costs in the CPM. It is for this reason that the RAs have proposed to establish the BNE Peaker fixed cost by taking account of the contribution to fixed costs such a plant would receive if it operated in the energy market.

	assumption is that poor availability generation will have an improved availability due to the financial incentives under SEM from day 1. This assumes that the financial incentives for availability in the SEM are equal to the incentives provided to generation in NI at the time of privatisation, which is not the case. Under the PPAs (Power Purchase Agreements) after privatisation a base load generator in NI received an availability payment plus fuel costs. Under the SEM a base load generator will receive the SMP as well as a Capacity Payment (equivalent to a BNE OCGT peaking plant) for generating. The Capacity Payment is considerably less under SEM than the availability payment in NI under the PPAs at privatisation, as only part of a base load generator's capacity is necessarily in the CPM. Another assumption is that the ROI units with poor availabilities will feasibly be able to make the necessary physical and operational changes required to improve their abilities for day 1 operation of the SEM. VP&E would caution against the real danger of overestimating the extent to which availability improvements can be made to poor availability units in ROI. The financial incentives to improve availability under SEM are not as strong as those in NI at the time of privatisation. It is also questionable whether the poor availability units in ROI are exactly the same as those in NI at the time of privatisation and whether the improvements can be achieved for day 1. We therefore consider that a historical view of	
	plant availability on the system should be taken from the SOs (System Operators) from the GAR (Generation Adequacy Report) in ROI and the seven year statement in NI. The SOs should also be charged with providing a forward view of the forced outage probability for each individual generator, based on that plant's historic availability. Where a generator's availability is particularly poor it should be considered as a unit under test, not counted as available capacity and not considered for Capacity Payments under SEM.	

AES	*Input data - Wind* Energy delivered from wind generation is largely unpredictable; it cannot be dispatched and is not responsive to frequency changes. Even if the annual average capacity factor is, say, one third, there still remains a high risk that this energy will not be delivered when it is needed for security of supply. AES considers that it is much too optimistic to include a capacity credit for wind generation based on forecast annual capacity factor and that awarding a Capacity Payment based on actual energy delivered over-compensates for the service provided[9]. In reality, flexible capacity will be required as back-up to the forecast energy delivered from wind. Yet this will not be reflected in the adequacy assessment.	*Wind* See above.

[9] Studies have been carried out realistic capacity credits. See, for example, “The Costs and Impacts of Intermittency”, page 48, by the UK Energy Research Centre .

	Input Data – Scheduled Outages Using a long-term average Scheduled Outage Factor (SOF) in the Capacity Required determination may produce a smother long term investment signal. If the RAs intend to use one-year data, this should not be adjusted for atypical events like FGD installation. During this period the plant will not be available and this fact cannot be ignored in any adequacy assessment for that particular year. *Input Data – Forced Outage Probabilities* It should not be assumed that FOPs for plant in the RoI will immediately reach NI levels. This is because ownership structures and incentives are different. A more accurate approach would be to use rolling historic averages, say for three or five years. The concern of the RAs that poorly performing plant would be rewarded is, in our view, short-sighted. In an energy only market, with prices derived by competition rather than regulation, poor performers would still enjoy the market price for their available plant. The RAs need to allow inefficiencies to be competed away by new entry, rather than introducing a barrier to new entry by artificially correcting for inefficiencies up front.	*Scheduled Outages* The RAs concur that the use of historic data would remove atypical events (in order to avoid year to year swings in the requirement calculation) and have decided to adopt this approach. *Forced Outage Probabilities* See above. The RAs do not accept that the use of average NI FOPs as proposed would introduce a barrier to new entry, nor would it remove the ability for inefficiencies to be "competed away". The CPM pot is based on a BNE peaking plant which recognises that new entrant plant below peakers will earn a contribution to fixed costs from the SMP market as well as from the CPM. The RAs believe the proposed CPM to be consistent with rewarding new entry while incentivising improvements in existing plant.

<table>
<tr>
<td>PPL</td>
<td>Input data

Currently the NI TSO uses connection agreements to determine plant capacities. PPL believes this is not a sufficiently accurate method of determining the capacity available to the system. It reflects the capacity of the connection and not the unit connected which in some cases can be markedly different. We therefore support the proposal in 6.2.1 to source the capacity of generating units directly from the Generators.

PPL believe that the Northern Ireland Seven Year Statement should not be regarded as being a good model for inputs. PPL are on record previously as having difficulties with the input assumptions. Some items from our previous comments are: -
• Moyle interconnector is included at 450MW but this is dependent on the being capacity available in Great Britain – no assessment is made for this. The capacity should reflect physical contracts in place.
• New plant is inherently less reliable in early years.
• It is not reasonable to assume replacement plant will perform the same as the plant it replaced.</td>
<td>The RAs agree that sourcing unit capacity from generators is a better solution and propose to write to all Generators under the provisions of the Generation Licences requesting unit capacities for use in the Capacity Requirement.

Whilst the RAs agree that ascertaining the availability of the Moyle Interconnector on a short-term basis needs to be by reference to secured trades (hence the CPM payment structure for Interconnectors), in a year ahead forecast the RAs consider it is reasonable to assume a high availability of the Moyle Interconnector. The other points relate to the FOPs to be adopted – see above.</td>
</tr>
</table>

	• The running regime has changed. During the winter months there is now substantial Generation on back-up fuels. Generation capacity can be markedly different and in is likely that FOP's are increased. The capacity requirement should reflect the capacity that is required by the system in Ireland. It should not reflect some theoretical system with theoretical planned and forced outages. This means that atypical scheduled outages should be included in the calculation and a best estimate should be made for the forced outage rates of installed capacity (based on expected reality). This should be relatively easy to do as the capacity requirement is worked out one year in advance so it is unlikely that there will be major differences from the recent historical position for FOP's and scheduled outages will be known. *Input data – Forced Outage probabilities* PPL regard the proposal to use the average FOP for NI plant and apply this to all plant on the island as risky. While there was a decrease in forced outages and average time for planned outages following privatization of the NI Generators, this was as a result of substantial investment by the Generators based on a long term view of return on investment. It is not clear to PPL that the same level of incentive will exist in the SEM.	
Airtricity	Airtricity cannot see how the regulatory authorities are better positioned than the TSOs to select the most appropriate demand forecast. Airtricity believe this decision should be made by the TSOs.	See above.

	Forced Outage Probabilities Airtricity strongly disagree with the notion that the FOP of the generation plant in RoI should be based on the average historic FOP for generation in Northern Ireland. The historic data clearly shows that much of ESB generation has a poor availability rate and high forced outage rate. There is no particular reason to expect this would change in SEM. The paper mentions that an improvement was noticed in the FOPs of generation in Northern Ireland in the early 1990's following the introduction of the PPAs. This event provides no indication as to the possible change in ESB plant performance in the SEM. The ESB portfolio consists of generators of different ages, technologies and manufactures than those in NI in the 1990's. This alone indicates at a straight comparison between FOR changes are not appropriate. Perhaps more significantly, ESB generation is part of a state owned regulated utility which may behave differently to market incentives than other generators.	See above.

MOYLE	Input data – Scheduled outages The adequacy assessment should use the most recent programme for scheduled outages. Where outages are known but not yet scheduled then the CREEP analysis programme can be used to schedule these efficiently. We have considerable reservations about the proposal to remove atypical events from the forecast as this could dilute its objectivity. As we commented in relation to demand forecasting, the process needs to be as transparent and consistent as possible. Input data – Forced Outages In relation to Forced Outage Probability (FOP), the Capacity Requirement as calculated for the CPM needs to be credible and to reflect what is reasonably achievable in the medium term. If capacity is expected to be inadequate for whatever reason then the economic signal through higher CPM payments should be at a level that will incentivise both availability improvement and investment in additional generation capacity. The price signal will then disappear. Reference has been made in the consultation paper to the availability improvements achieved in NI as a result of the introduction of the PPAs in the early 1990s. The improvements were due to the incentive effect of the availability payments based on previous rather than expected performance. The lesson is that the SEM Capacity Requirement should be based on availabilities achieved in the recent past rather than what is expected. This should not be	*Scheduled outages* See above. *Forced Outages* See above.
	seen as a reward for poor performance but an incentive to improved performance. Based on these considerations, the approach used in NI to date, as described in the consultation paper, seems to be generally appropriate, although there is evidence that actual availabilities have not been as high as assumed in recent adequacy assessments and a review of these may be timely.	

SYNERGEN	*Input data – Generation Capacity* Synergen prefers for generation capacity to be based on connection agreement data and modified by any formal notifications by the generator as provided to the TSO because this removes any element of subjectivity. Synergen entirely opposes any Regulatory Authorities review to strip out atypical events. If some smearing methodology is required (and Synergen is not persuaded that there is a need) then this should be algebraically set out by the TSOs, and be subject to cap and floor arrangements to ensure stability. *Input data – Forced Outage Probabilities* Synergen would not support utilisation of generators predictions for FOPs as it could be considered as the submission of a “commercial” parameter and therefore subject to manipulation – initial consideration suggests that generators would have an incentive to take more pessimistic views of reliability to drive up overall capacity requirements (and hence payments) and this clearly unsustainable. On the same basis Synergen opposes Regulatory Authorities exercising discretion or having a direct involvement in determining FOPs. The concern is that as the choice of the values (particularly in the first year of the SEM) could be primarily driven by considerations as to the cost of various FOP assumptions, instead of working out the most accurate prediction and having that value feed into the assumed capacity calculation.	*Generation Capacity* See above. *Forced Outage Probabilities* See above.

	Input data – demand Synergen does not believe that the Regulatory Authorities should select "*the forecasts that they believe are most likely to reflect demand in the relevant jurisdictions*". This introduces a level of regulatory subjectivity that is entirely inappropriate. Furthermore, demand forecasting is not usually considered to be core regulatory function and therefore the Regulatory Authorities would need to procure additional expertise to replicate the TSOs' core expertise which appears an inefficient use of resources. The TSOs should produce a central demand forecast assuming average weather conditions consistent with international best practice for each jurisdiction. The demand forecast should be developed utilising a defined common methodology (upon which the TSOs consult prior to utilisation) without any Regulatory intervention. There should then be a process of consultation to allow all stakeholders to comment prior to the TSOs publishing the final demand forecast.	*demand* See above. In seeking to forecast the demand in their respective jurisdictions, the TSOs aim to produce as accurate a forecast as possible. The involvement of the RAs in selecting an appropriate forecast for the year in question reflects the RAs role in supporting the market arrangements. The selection will be made after discussion with the TSOs on the forecasts and the assumptions made. Since the aim of the TSOs in forecasting demand is to establish the best forecast they can, the RAs do not see any advantage to be gained in undertaking a consultation on the forecasting process.
NIE	*Input data – Forced outage probabilities* Forced outage probabilities (FOPs) should be based on historical performance. An understanding of the reasons behind the post-privatisation increase in the availability of NI plant confirms that the RAs' proposal to apply the average NI FOPs to generating units in RoI would be likely to lead to a capacity shortfall. *Input data – Scheduled outages* In the interests of the stability of the CPM, scheduled outage durations (SODs) should be based on historical data on planned outages averaged over a number of years to remove the effect of atypical circumstances. The proposal to use actual planned outages will produce swings in the capacity requirement solely because of the generator maintenance cycles.	*Forced outage probabilities* See above. *Scheduled outages* See above.