Single Electricity Market

Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism

Decision and Further consultation Paper

13th February 2007

AIP/SEM/07/14

I. INDEX

II. INTRODUCTION

On 15th September 2006 the Commission for Energy Regulation and the Northern Ireland Authority for Energy Regulation ("the Regulatory Authorities") published a consultation paper entitled *"Fixed cost of a new entrant peaking plant for the capacity payment mechanism"*[1]. The paper set out three possible methodologies for determining the price of peaking capacity for setting the annualised capacity pot and discussed the issues involved in each of these approaches setting out the pros and cons.

Comments were invited on the methodologies set out in the consultation document by 13 October 2006. Responses were received from ten 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.

Certain aspects of the previous consultation will also be further consulted upon and are addressed in section VI & VII. These sections will look into both the criteria for selecting the preferred BNE technology, and also the methodology for obtaining an infra marginal rent estimation for the BNE peaking plant.

A decision paper on the issues raised in this consultation will be published on the 27th April 2007. This paper will also include the final BNE number to be used in the calculation of the CPM annualised pot for 2007.

The structure of this document is as follows:

Section II introduces the consultation paper and describes the contents within;

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

Section IV concludes on the RA's preferred methodology of calculating the Price element for setting the annualised CPM pot;

Section V examines further the technology options available in considering which generation set represents a best fit for the BNE peaking plant;

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

Section VI considers participant responses and concludes on the derivation of the non technology specific capex costs;

Section VII considers the options in deriving an estimation for the infra marginal rent that the selected BNE peaking plant might expect to earn from both the energy and ancillary service market;

Section VIII invites participants to comment on sections VI & VII of this consultation relating to technology choice and infra marginal rent derivation; and

Appendix 1 outlines the RA's response to comments received from the last consultation paper on calculating the fixed costs of a BNE peaking plant.

Views are invited on any of the issues raised in this consultation document. These are requested by 13th March 2007 and should be sent to peter.halligan@ofregni.gov.uk. The RAs intend to publish all comments received. Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential.

III. BACKGROUND

In July 2005 the Regulatory Authorities (RAs) set out the High Level Design Principles of the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM). In the High Level Design Principles the RAs indicated their proposal to develop a fixed revenue capacity payment mechanism that 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 July 2005 were incorporated in the design of the CPM and in the Trading and Settlement Code (TSC). In December 2005, the RAs published a draft version (Version 0.10) of the proposed All-Island TSC for the SEM that included the provision for a number of input parameters to be set by the RAs. Following industry discussion, Version 1.0 of the TSC was published in February 2006. In March 2006 a consultation document was published that incorporated a more detailed consideration of the comments received on the design of the CPM and put forward a number of alternative options for the CPM and the processes that the RAs propose for determining the annual capacity payment and the general process by which it is proposed that input parameters to the CPM would be set.

The March 2006 paper reiterated the proposed outline of the CPM for the SEM suggesting that annual capacity payments should be fixed and that the annual fixed sum be divided into a number of within year pots, i.e. Capacity Periods. The paper also set out proposals for the determination of the annual capacity payment. The paper proposed that the annual aggregate capacity payments should be set by multiplying an appropriate level of required generation capacity by the relevant fixed costs of a best new entrant peaking generator.

The RAs proposed that, for the purposes of determining the annual total for the CPM, the cost of new entrant generation should be assessed in terms of a 'Best New Entrant' (BNE) peaking plant. The figure calculated would be expressed in €/kW per year (as an annualised payment) and multiplied by the capacity requirement as determined from the analysis described above to calculate the annual capacity payment. As there currently exists in the Republic of Ireland (RoI) a mechanism for determining the costs of a BNE *baseload* plant, it was proposed that the same basic methodology should be used to determine the annual fixed costs of a BNE peaking plant.

In determining "Best" when considering our new entrant, a range of commercial considerations have been taken into account whilst deriving the fixed costs, these include: TUoS, gas and electrical connections, gas charges and tax; all of which apply to an IPP generator.

Responses to the September 2006 consultation broadly supported methodology 2 for determining the cost component of the annual fixed sum; however some reservations were expressed over the proposal to account for SMP and Ancillary Service market revenues when determining the fixed costs of a BNE peaking plant to be used for the purposes of setting of the annual sum.

This paper broadly considers the issues raised in considering how to determine an appropriate annual capex value of a BNE peaking plant to be used for the purposes of setting the annual sum. Section VII looks at options for deriving both the energy and ancillary service rents a BNE peaking plant might expect to earn from in the new market.

IV. PREFERRED METHODOLOGY

The CPM identified for the SEM requires the calculation of the fixed capital costs of a best new entrant peaking plant. In September 2006 the RAs consulted upon three alternative costing methodologies that it considered potentially appropriate to estimate the annualised cost of a BNE or marginal cost of incremental capacity peaking plant in the SEM. These were:

1) Assessing the market equilibrium price of a peaking plant (marginal cost of incremental capacity) in the SEM based on an assessment of VOLL, LOLP and the peaking plant's forced outage probability.

2) Assessing the cost of peaking capacity in the SEM by estimating the full project costs that would be incurred by a developer of a new BNE peaking plant and taking into account the estimated infra marginal rent realised from participation in the energy and ancillary service markets.

3) Assessing the cost of peaking capacity in the SEM based on a narrowly defined role for the peaking plant, that of a 'social benefit' operating as contingency reserve only, and adjusting the investment criteria for a BNE peaking plant given this narrow role.

1. Methodology One

All respondents considered Methodology One – an assessment of the market equilibrium price for peaking plant in the SEM – to be inappropriate for application to the SEM. Most of the respondents' concerns regarding the application of Methodology One to the SEM surrounded the 'correct' calculation of a single figure for the value of lost load (VOLL).

As was suggested in the consultation document, determining the 'true' value of lost (unserved) load (VOLL) is problematic and although in a perfectly competitive market VOLL should represent the willingness of consumers to pay to ensure continued load, no consumer has an identical willingness to pay. Determining a single VOLL value for application to the SEM will therefore involve a degree of subjectivity. Most respondents agreed with the inherent difficulty associated with the calculation of VOLL for the SEM. One respondent suggested that there is no accepted methodology for calculating VOLL and others pointed to the subjective nature of any potential assessment of VOLL for the SEM. Another suggested that insufficient time was available to attempt to calculate a true VOLL for the SEM, even if the approach was appropriate.

One respondent suggested that the application of Methodology One was further complicated by the potential correlation between VOLL and the Loss of Load Expectation (LOLE) – also referred to as Loss of Load Probability (LOLP) – given that VOLL is often back calculated as the number necessary to maintain a given LOLP security standard. The RAs agree that there is a correlation between VOLL and LOLP. If the spot price was allowed to reach a 'true' VOLL, and thereby in theory result in generation adequacy, uncertainty of capacity adequacy may still prevail due to the unique nature of the commodity 'electricity.' Firstly, electricity cannot be stored therefore supply and demand must match simultaneously throughout the day. Secondly, the pattern of electricity supply and demand fluctuates considerably throughout the day and over the course of a year. Thirdly, the electricity system must be in physical supply and demand balance at every point on the network continuously to meet physical constraints of voltage, frequency and stability. In addition the fundamentals underpinning the operation of the electricity market are far from perfect – in particular the demand for electricity is a notoriously inelastic derived demand that responds relatively poorly to price signals.

The combination of these distinctive characteristics helps define the role of generating technologies in the electricity market as each plant is characterised by a set of capabilities and broad definitions that allow it to respond, either significantly or in a limited way, to changing supply and demand requirements. Attempting to reflect the uncertainty inherent within electricity generating technologies is calculated using the probability that load may be lost by any plant type at any time, or Loss of Load Probability (LOLP). LOLP is intended to take into consideration the quantity and mix of the available capacity in relation to the forecasted load and the probabilities of forced outages and is defined as the probability that, at any particular time, demand will exceed available generation. As a result LOLP may also be considered an expression of generation adequacy and is correlated to VOLL.

In summary the RAs agree that difficulty surrounding the determination of VOLL for the SEM is likely to result in sub optimum assessment of the market equilibrium price of a peaking plant. As a result the RAs do not propose to adopt Methodology One to determine the price of a new entry peaking plant for the SEM.

2. Methodology Three

All respondents considered Methodology Three - assessing the cost of peaking capacity in the SEM based on a narrowly defined role for the peaking plant, that of a ‘social benefit’ operating as contingency reserve only, and adjusting the investment criteria for a BNE peaking plant given this narrow role – as inappropriate for application to the SEM.

Most respondents argued that the cost of a BNE peaking plant should be assessed on the basis of commercial/merchant new entry, and therefore evaluated using a commercial WACC and amortisation period rather than that applied to a notional ‘social good’ as outlined in Methodology Three. One respondent suggested that using the measure of ‘social benefit’ would not deliver efficient commercial entry without the backing of a mutualised public vehicle to secure long term finance. It was argued that this would operate against the principle of the market driven SEM.

The RAs consider that Methodology Three is inappropriate for application to the SEM.

3. Methodology Two

Of those respondents who commented on the proposals, all broadly supported the proposed approach outlined in Methodology Two - assessing the cost of peaking capacity in the SEM by estimating the full project costs that would be incurred by a developer of a new BNE peaking plant and taking into account the estimated infra marginal rent realised from participation in the energy and ancillary service markets. A CPM based on the cost of a BNE peaking plant is intended to address the shortcomings of an energy only market by compensating all market participants by an amount equivalent to the capital cost of a peaking plant providing the marginal unit of generation for the market.

Although all respondents considered Methodology Two to be the most appropriate methodology to determine the cost of new entrant peaking plant for the SEM, a number of issues were raised, in particular those regarding:

a) Revenue assumptions

b) Cost assumptions

c) Fuel choice

d) Technology issues

(a) Revenue assumptions

Some respondents questioned the intention to take into account infra marginal rent when calculating the fixed cost of a BNE peaking plant. The RAs have indicated that, in the assessment of the costs of a BNE peaking plant, an expectation of profits from the energy and ancillary service markets that such plant will reasonably expect to earn will be deducted from the fixed cost of a BNE peaking plant. The BNE peaking plant will expect to earn infra marginal rent from operation in the energy market. Similarly the plant would be expected to earn revenue in the ancillary service market, in particular for the provision of Primary, Secondary, Tertiary, Replacement Reserve and Reactive Power. Revenue derived through these Ancillary Service (AS) arrangements will not need to be adjusted for any production costs incurred as these will be compensated through the energy market and therefore a reasonable estimate may be obtained by reference to existing contracts and AS rates for similar peaking capacity in ROI. The RAs note that this approach may underestimate the AS revenue since it is possible that the peaking plant would in reality be constrained on over and above its estimated running schedule and may be asked to provide greater amounts of reserve, however this is difficult to estimate and the RAs have decided that it will not be taken into consideration.

If a CPM was based on the capital costs of a BNE peaking plant without taking into account infra marginal rent earned in the energy and ancillary service markets, over compensation would occur as the CPM would be based upon the fixed cost of a peaking plant that primarily provided only reserve and was wholly compensated for that provision only by the CPM. In reality compensation is very likely to also occur through activity in the energy market and the ancillary service market, if this is not taken into account; the CPM will over compensate all generators.

Several respondents raised concern over the calculation of energy market revenue; given the limitations of price forecasting. Respondents suggested that identifying both energy and ancillary service revenue may be difficult and subjective and could therefore erode confidence in the long-term price signals for new investment.

The RAs accept that any fuel/energy price forecasts carry a statistical uncertainty. However the link between fuel prices and the calculation of SMP will remain relatively constant – higher fuel prices will lead, all things being equal, to higher SMP. Therefore the assessment of energy market operation of a peaking plant will also remain constant even though its variable costs will increase in line with fuel prices.

Some respondents suggested that, although a peaking plant might make infra marginal rent in the energy market in the early years of operation, as the plant aged and its efficiency subsequently declined, so would its corresponding energy market revenue.

The RAs consider that a peaking plant might have an economic life considerably in excess of the book life assumed in the consultation document. As a result the peaking plant will continue to earn some energy market revenue beyond the 15 year life over which the investment is amortised.

Another concern raised was that adjusting the BNE capital cost to account for energy and ancillary service market revenue would lead the peaking plant to seek to recover this money through higher bids into the energy market.

Given that our notional peaking plant will be making normal profits after the deductions for Energy and Ancillary Service payments the RAs are of the view that such a bidding strategy would lead to over compensation for the peaking plant, they would run the risk of not being scheduled, and also be in contravention of the bidding principles which advocate SRMC bidding for all plant types.

It was suggested by one respondent that a peaking plant will be obliged to recover its start up and no load costs in the energy market but that, given the design of the Uplift mechanism, it will be unlikely that any infra marginal rent will be earned above the marginal cost of the unit plus start up costs. However, the RAs note that the design of the uplift mechanism as set out in consultation AIP/SEM/230/06 does not preclude the possibility of the BNE peaking plant from making infra marginal rents from the Uplift mechanism per se.

The RAs will be investigating the potential infra marginal rents earnings from the SMP through the methodologies set out in section VII of this paper.

Some respondents felt unable to comment in detail on the assumption of ancillary service revenue as they were unable to replicate the figures. One suggested the figures appeared reasonable, but others suggested that the assumed ancillary service revenue was too high and questioned the rationale underpinning the removal of ancillary service revenue.

As discussed above, the RAs consider it appropriate to remove ancillary service revenue from fixed cost a new entrant peaking plant – if the CPM included a reserve payment made under the auspices of an ancillary service payment, then plant would in effect be paid twice for providing an element of reserve under the CPM and via ancillary services. However, the RAs recognise concern over the calculation of ancillary service revenue and the estimated ancillary service revenue is described in greater detail in section VII part 2.

One respondent suggested two alternative approaches that might mitigate the forecasting uncertainty surrounding the calculation of peaking plant revenue. These included not deducting ancillary service and energy market revenues, but applying an index to the fixed costs, or introducing an annual 'k-factor' that would correct ex post and under/over estimates of revenue.

It is not clear how the application of an index to fixed costs would remove uncertainty as the index rate to be applied would be subject to change. Correcting revenue ex post would distort the CPM by introducing volatility into investment signals, and failing to fully reflect the capacity requirement of the market going forward.

(b) Cost assumptions

Several respondents suggested that the indicative BNE capital cost assessment did not fully take into account the gas capacity charge a gas-fired peaking plant operating in the SEM would incur. Given that gas capacity must be booked on an annual basis it was suggested that the cost of gas capacity might amount to around €9m. At present the gas capacity charge is an annual fee determined by the volume of gas transmission capacity booked by the relevant shipper – therefore a peaking plant operator will be required to book sufficient transmission capacity to ensure daily operation – even though in reality he may expect to operate on only a limited number of days in the year. For illustrative purposes, a 180 MW gas-fired plant might incur an annual capacity charge of less than €6 million. However, the secondary market allows shippers to trade their daily capacity positions so a gas-fired peaking plant operator will not incur the full annual gas capacity charge associated with its plant. Clearly the ability of the peaking plant operator to recover its gas capacity charge will depend on the liquidity of the secondary market.

The RAs are also aware that BGE are proposing changes to the capacity booking duration, moving to a day ahead facility in June. Such a facility would allow the BNE peaking plant to purchase its gas capacity requirement based on the day ahead indicative schedule as published by the SMO. In effect this facility would eliminate the stranded fixed cost of booking gas capacity on an annual basis.

The RAs seek the views of respondents both on the liquidity of the secondary market and of the effect of the proposed changes to BGE's gas capacity booking arrangements under the oversight of the CER in complying with directive EC 1775.

Several respondents suggested that the delivered price of gas assumed in the consultation appeared low. In September 2006, when the consultation was published, the forward price for the 2007 gas year was around 55p/therm. In January 2007 this had fallen to below 40p/therm. The changing fuel price forecasts serves to illustrate the difficulty associated with attempting to define the variable operating cost of a new entrant peaking plant in a changing market. However, as discussed above, the variable cost will affect the operation of the plant and its assumed revenue, but the impact on the BNE capital cost will be limited due to the corresponding upward impact on SMP.

Several respondents suggested that the weighted average capital cost (WACC) adopted in the consultation document, that was based on that adopted in the BNE baseload plant, was too low, with most considering 10-12% a more acceptable estimate of the real cost of capital. One respondent suggested that a higher WACC might be applied to peaking plants given that most of its income would be derived from the volatile CPM with additional regulatory risk.

The RAs are not persuaded that a peaking plant in the SEM would face more systematic (i.e., undiversifiable) risk than a BNE baseload plant and should therefore require a higher rate of return. This is largely because of the design of the market: the RAs have deliberately chosen to include an explicit capacity payments mechanism in the market design, and one with a significant degree of certainty over when and at what price available capacity will be paid. A peaking plant's income will therefore be no more variable (relative to the state of the economy) than that of a baseload plant in the SEM. A peaking plant's income might be more variable compared with what a baseload plant would earn in an energy only market, but the SEM is not an energy-only market.

A number of respondents questioned the use of a tax rate applicable to the RoI to determine the cost of a new entrant peaking plant, suggesting that it would discriminate against new entrants in NI.

Based on current system dynamics and subsequent locational signals, gas connections costs, gas capacity charges and tax a BNE IPP peaking plant would have sited in ROI. The fact that ROI has a lower WACC is a function of the differing tax regimes north and south which is beyond the remit of the RAs. It is important to note that increasing the WACC to account for the higher corporation tax in NI will still not make it more likely for an IPP peaking plant to site in NI all other things being equal i.e. increasing the WACC to account for higher corporation tax will simply increase the opportunity cost of citing in the North opposed to the South for rational profit maximizing IPP peaking plant; whilst the differential is accounted for in the CPM, the differing tax regimes will still exist. Therefore the RoI tax rate is deemed appropriate. However, this does not preclude the possibility of future BNE prices being based on a notional plant citing in the North which would take into account the higher rate of corporation tax.

(c) Fuel Choice

It was suggested in the consultation document that fuel choice for a peaking plant would be natural gas and the technology choices reflected this assumption. One respondent suggested that a gas-fired peaking plant would not be viable unless located adjacent to an existing gas-fired facility given the high costs associated with gas connection infrastructure spread over a relatively small number of operating hours. Cost uncertainty surrounding purchasing a daily forward gas option, the gas capacity charge and high price of winter gas (when a peaking plant might be expected to operate) led to the suggestion that a peaking plant operating on distillate might be a more appropriate technology choice for the SEM.

However, as observed by VPE, Clause 6 of CER's 'Authorisation to Construct' a power station contains a requirement for dual fuel capability at a generating unit. For the basis of this paper it is assumed that the notional peaking plant will be compliant with this requirement and that its primary fuel source is natural gas. However, the RAs will reassess fuel choice with reference to the relevant dual fuel requirements in place in ROI prior to publication of the final number and in light of responses received on the liquidity of the secondary market for gas capacity and of new BGE capacity booking arrangements.

(d) Technology Options

These will be discussed in the next section V

In Summary the RAs deem Methodology 2 as appropriate in deriving the price element of the CPM for the SEM.

V. TECHNOLOGY OPTIONS

This Section clarifies the proposed approach and key assumptions for determining the optimum technology which is proposed for the role of a new entrant peaking plant in the CPM in accordance with Methodology Two.

Size

There are relatively few commercially available gas turbines to choose between in deciding the most appropriate one for the role of a new entrant peaking plant in the CPM.

In the range 40-180 MW there are only half a dozen or so open-cycle gas turbine options:

GE LM6000 PD SPT	44 MW
GE 6FA	74 MW
GE LMS100	92 MW
GE 9E	124 MW
Siemens SGT2000E	159 MW
Alstom 13E2	177 MW

Note: net power output based on natural gas at ISO (International Organisation for Standardisation) conditions.

Start-up

As previously stated, peaking duty requires a plant which is reliable and flexible to operate. In particular, it suits a generation technology with short start-up and shut-down times.

All of the gas turbines listed above have achieved full output within about 20 minutes (or less) from notification to start. The only exception is the GE 6FA which requires a sustained period (30 minutes) at limited output to allow for thermal expansion. With an overall start-up time of 70 minutes, the RAs do not consider this to be an appropriate choice of gas turbine for the CPM as it falls far outside the TSO's criterion for Replacement Reserve, i.e. 20 minutes start-up.

Proven track record

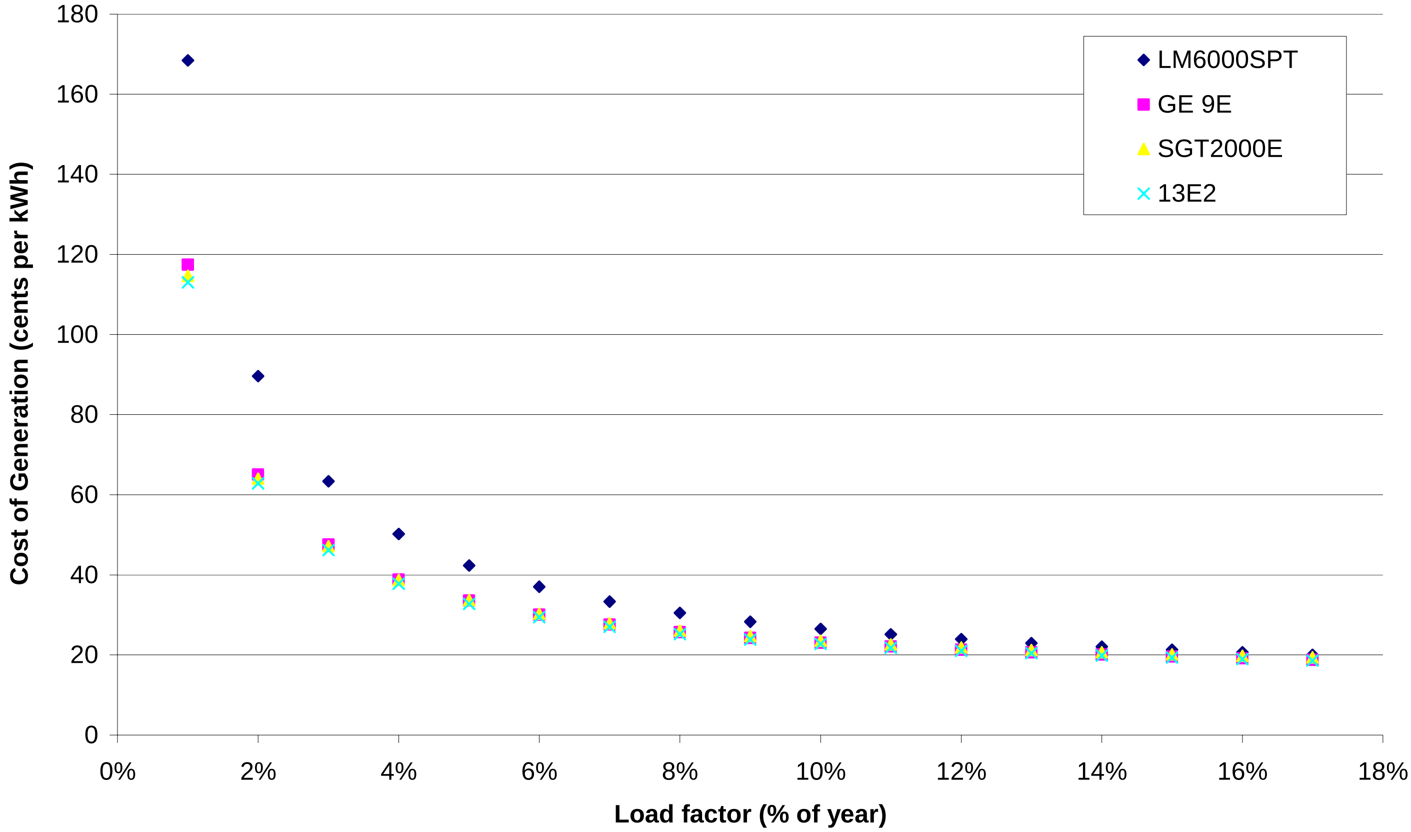
The peaking plant chosen for the CPM should be commercially available and appropriate, both in terms of fuel type and technology, to the existing All-Island electricity system.

The GE LMS100 is a new gas turbine that combines components from both heavy-duty and aero-derivative gas turbines (commonly referred to as a *hybrid* gas turbine). Although it offers higher cycle efficiency than all of the others, it can be argued that it's limited operational experience makes it an unsuitable choice for the best new entrant peaking plant at the present time.

Cost

Some respondents suggested that a smaller aero-derivative gas turbine was more appropriate for peaking duty than the alternative heavy-duty industrial type. The RAs note that while both the Rolls-Royce Trent and GE LM6000 have faster start-up times, this comes with additional costs of perhaps a 50 per cent premium on the specific EPC price (€/kW) over larger heavy duty industrial gas turbines.

The graph below provides a comparison of the total costs of generation for each of the candidate gas turbines having excluded the ones noted above.



On the basis of least cost, the RAs propose that the best new entrant plant for the CPM should be based on a large open-cycle heavy duty industrial gas turbine (i.e. from the above analysis the LM6000SPT is also excluded).

Best available technology

Of the three remaining gas turbines that did conform to all the selected criteria, the RAs have selected the generation set which is most consistent with the IPPC directive relating to the use of "Best Available Technology" (BAT) i.e. the machine with the best efficiency rate.

GE 9E	33.5%
Siemens SGT2000E	34.0%
Alstom 13E2	36.3%

Note: net efficiency (LHV) based on natural gas; this may change with fuel choice

In summary, therefore, the RAs propose to employ a notional BNE peaking plant on the technical and cost characteristics of an Alstom 13E2 for the purposes of deriving the price element of the CPM.

VI. DECISION ON NON TECHNOLOGY SPECIFIC CAPEX

The BNE base load costing methodology previously[2] employed by the Commission for Energy Regulation uses a range of assumptions that broadly fall into four categories. All respondents felt that such an approach should be applied to the new entrant peaking plant.

- Operational performance
- Economic and financial assumptions.
- Investment costs
- Recurring costs of operation and maintenance

Operational performance

The BNE peaking plant has an as-new net output of 177.4 MW in open-cycle configuration when fired on natural gas. This has been reduced to 172.0 MW to account for the degradation in power output over its lifetime of operation.

It has as-new net efficiency of 36.3 per cent (lower heating value) but this has been reduced to 35.6% to take account of the degradation in efficiency over its lifetime of operation.

The average annual plant maintenance outage time has been estimated to be 13 days per year. The forced outage probability is assumed to be 2 per cent. This results in an overall plant availability of about 95%.

Economic and financial assumptions

Current price (nominal price) is a term used to define costs and benefits and includes the effect of general price inflation. Constant Price (real price) refers to a value from which the overall effect of general price inflation has been removed. Using constant prices ensures that the future cost and benefits are estimated in the same units as the cost and benefits measured at the time the decisions to invest in the project are made. The BNE is calculated using constant price.

[2] The CER's BNE Price is currently in its eighth revision.

The rate of return earned by a new entrant must be sufficient to cover the risk of entering the SEM. The RAs have reviewed the proposed weighted average cost of capital (WACC) value in light of responses to the previous Consultation. After review, the RAs consider that the WACC figure of 7.83% is appropriate for the BNE Peaking Plant as it was for the BNE base loader cost derivation in ROI, and do not agree that a peaking plant will carry any greater risk than a base load plant in the SEM. As previously stated the RAs have chosen to include an explicit capacity payment mechanism in the market design, and one with a significant degree of certainty over when and at what price available capacity will be paid. A peaking plant's income will therefore be no more variable than that of a baseload plant in the SEM. .

It is also useful to note that although the plant life expectancy is 25 years, an economic life of 15 years has been chosen to reflect the maximum period of time an IPP developer would be prepared to recoup its full investment cost.

Investment costs

Since publishing the Consultation in September 2006, the RAs have re-visited the estimated capital costs of developing a BNE Peaking Plant:

– Procurement of site: A notional cost €2.5 million is deemed to represent the value of a permitted site suitable for the development of a peaking plant.

– Soft costs comprising the developer's own internal costs, environmental impact assessment, engineering, and financing and legal costs: €1.5 million

– Plant and equipment (engineer, procure and construct basis) along with shallow costs for electrical and gas transmission connections: €69.6 million (including 3 per cent contingency on the EPC contract)

– Other costs (including owner's engineering, O&M mobilisation payment, contingency, spares and interest during construction costs: €7.8 million

The total capital cost of developing a notional 177 MW open-cycle gas turbine is estimated to be €81.4 million which is equivalent to €473 per kW.

Non-fuel operation and maintenance costs

Non-fuel operation and maintenance comprises both fixed and variable costs. The allocation of fixed and variable costs is very subjective. For the purposes of this consultation, we assume that the long-term service agreement (LTSA) is structured:

– LTSA fixed operation and maintenance costs: €560,000

– Variable operation and maintenance costs: €¢1.39 per kWh

Other fixed costs

– Transmission charges: €920,000

– General and administrative costs: €730,000

– Insurance: €1,730,000

– Rates: €1,750,000

Annualised cost of capacity

Based on the assumptions described above, the fixed annualised cost of BNE Peaking Plant before adjustment for infra marginal rent and ancillary service revenue is estimated to be €87.9/kW per year:

VII. DERIVATION OF INFRA MARGINAL RENT ESTIMATION

1. *Options for the estimation of energy infra marginal rents*

In order to assess the infra marginal rent a BNE peaking plant might expect to receive from the energy market, critical assumptions must be made about the future value of SMP realised in the trading periods in which the peaking plant is assumed to be active in the energy market. It is assumed that, as a profit maximising entity, the BNE peaking plant will operate in all those trading periods that provide it with infra marginal rent – more commonly referred to as a positive *spark spread*. The data from which the infra marginal rent will be derived will be validated and bench marked as per the current RA model validation work stream. There are two broad potential options for calculating the Infra marginal rents derived from the energy market.

1.) Calculate the infra – marginal rents using validated plexos SMP outputs & BNE SRMC, Start Up and No Load costs.

This methodology involves calculating the SRMC of the BNE peaking plant and is then compared to the shadow price estimations to give an indicative unit commitment for our peaking plant, from this running schedule we would then be able to calculate the infra marginal rents by subtracting the combined BNE marginal cost of generation (including no load and start up) from the SMP (including uplift) estimations from the validated model. Note that trading periods where the BNE SRMC is less than the shadow price, but the combined cost of running our BNE peaking plant is greater than the SMP including uplift in a particular trading period will not be accounted for. This will be done in an iterative process.

$$IMR = \sum_i \left(SMPWU_i - SRMC_i - NL_i - SU_i \right)$$

for all i where:

$$SRMC_i \leq SMPMU_i \quad \& \quad SRMC_i + NL_i + SU_i \leq SMPWU$$

Where:

IMR = Infra-Marginal rent earned by the BNE peaker

i = scheduled trading period

$SMPWU_i$ = System Marginal Price (including uplift) in period i

$SRMC_i$ = short-run marginal costs of best new entrant peaker in period i

NL_i = no-load costs of BNE peaker in period i

SU_i = start-up costs of BNE peaker in period i

$SMPMU_i$ = System Marginal Price minus uplift (=Shadow Price) in period i

2.) Introducing the BNE peaking plant into the Plexos run.

One of the drawbacks to the first option is that it fails to derive a realistic running schedule for the peaking plant. Inputting the notional BNE peaking plant into plexos run will give a more realistic running schedule and accurate proxy for determining the infra marginal rent. This option has two variations;

a) The first being to input a scaled back BNE peaking plant so as not to dampen the SMP prices, i.e. a 1MW mini peaker would be introduced into the Plexos run with other associated parameters also scaled back. However the Plexos software could prove problematic in the treatment of such a small unit.

b) The second option is to complete two plexos runs, one with the BNE peaking plant and all its true characteristics and one without. A unit commitment schedule would be derived for the BNE peaking plant from the first plexos run and the actual infra marginal rent calculation would then be derived using the original SMP estimations from the plexos run without the BNE peaking plant included.

2. Methodology for the derivation of Ancillary service revenue

A further deduction to the BNE plant cost will be made to account for revenues earned through the Ancillary Service arrangements. The key revenue stream for a peaking plant is the provision of Primary, Secondary, Tertiary and Replacement Reserve. Revenue derived through these Ancillary Service (AS) arrangements will not need to be adjusted for any production costs incurred as these will be compensated through the energy market and therefore a reasonable estimate may be obtained by reference to existing contracts and AS rates for similar peaking capacity in ROI. As previously noted, this estimation is likely to be understated given the likelihood of the peaking plant being constrained on and providing greater levels of operating reserve during periods of synchronisation. However, given the difficultly in deriving such an estimate it has not been taken into account for the purposes of this revenue estimate.

An estimation of future peaking plant earnings from the Ancillary Service arrangements has been derived using 2007 ROI rates for Operating Reserve and Reactive Power[3]. A proxy based on ROI data was chosen given that this is where a BNE peaking plant should locate based on current system dynamics and subsequent locational signals.

The assumptions made in the production of the estimated earnings for each of the ASs are set in the paragraphs below. It should be noted that the estimates produced here are based on EirGrid's existing AS arrangements. SONI and EirGrid are currently reviewing their respective AS arrangements (termed System Support Services in NI) with a view to harmonising them under a single set of arrangements. It is therefore highly likely that new AS arrangements will apply in the future and will be taken into consideration when determining the Price element of the CPM annualised pot in future years.

<u>Operating Reserves</u>

Operating Reserve payments are based on the availability of the generator to provide each category of reserve (see reserve category list below). In order to provide Primary, Secondary, Tertiary 1 and Tertiary 2[4] reserve it is assumed that the generator has to be synchronised, i.e. the generator must be 'on-line'. The amount of time that a BNE peaking unit is 'on-line' should, by its very nature, be relatively low but is subject to market and operational conditions, the estimate used in this analysis will be based on running hours as determined by the analysis carried out in deriving the hours the BNE peaking plant is likely to run (see earlier in the discussion of the estimation of infra marginal rents). It is assumed that Replacement reserve can be provided when the unit is 'off-line' but available. The availability of the unit will be based on information for the selected notional unit. As the availability to provide Replacement reserve is much higher than the availability for the other categories of reserve, payments for

[3] EirGrid's rates for Ancillary Services can be found in the 'Ancillary Services Statement of Payments for 2007' on the EirGrid website www.EirGrid.com.
[4] Depending on the notional BNE machine dynamics, TOR 2 provision maybe available when generation set is "off line".

Replacement reserve are much higher than for the other categories of reserve. Also listed below are the €/MWh rates currently employed by Eirgrid for the provision of reserve (note that these rate are reduced when there is over provision of the service). The exact MW amount of reserve that the BNE peaking plant will provide in each of these categories will be dependent on the size of the unit that is ultimately chosen.

The different Reserve types are defined as follows:

Reserve Type	Response Time	2007 ROI Rate (€MWh)
POR	5 - 15 secs	1.91
SOR	15 - 90 secs	1.73
TOR 1	90s - 5mins	1.58
TOR 2	5 - 20 mins	1.58
RR	20m - 4 hrs	1.19

Reactive Power

Reactive power revenues are divided into Utilisation and Availability payments. Given that a peaking unit is likely to have a relatively low utilisation factor but a high availability factor, the revenue here is mostly related to availability. The same availability and utilisation factors are used here as for Operating Reserve calculations.

Reactive Power Payments	Rates (€/MVArh)
Leading Availability	0.152
Lagging Availability	0.152
Leading Utilisation	1.28
Lagging Utilisation	1.28

VIII. VIEWS INVITED

Views are invited on any of the issues raised in this consultation document. These are requested by 13th March 2007 and should be sent to peter.halligan@ofregni.gov.uk. The RAs intend to publish all comments received. Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential.

APPENDIX 1 – COMMENTS RECEIVED ON THE FIXED COST OF A NEW ENTRANT PEAKING PLANT CONSULTATION DOCUMENT AND RESPONSES FROM THE REGULATORY AUTHORITIES

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 are in agreement with proposals or analysis set out in the consultation are not included.

Document Title:	**Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism**
Document Ref Number:	AIP/SEM/124/06
Comments to be returned by:	13/10/2006
Comments returned to:	Peter Halligan (peter.halligan@ofreg.gov.ni)
Document Author:	Peter Halligan

Respondee	Heading / Comments	Response
	Methodology 1	
ESBI	The VoLL approach has been used in various markets and is conceptually attractive. The discussion presented in the paper, and further examples from the literature, demonstrate the fatal flaws, however. There is no generally accepted and proven method for calculating the key VoLL figure, which can vary significantly according to economic conditions, infrastructure, between customers and by season and time of day. Rather than discussing the various figures in the paper any further, ESBI proposes that this methodology should not be considered as it is not appropriate for a market where participants are already concerned about revenue adequacy.	The RAs are of the view that Methodology one has merit in its simplicity and transparency, it would also allow for a stable year to year peaking price. However the RAs also accept the limitations of methodology 1 in accurately reflecting the true cost of peaking capacity.

NIE	NIE considers that <u>Method 1</u> is not appropriate because of the uncertainty inherent in both its independent variables. • It relies on estimates of the Value of Lost Load (VoLL) and the desired generation security standard expressed in terms of the Loss of Load Expectation (LoLE). However, VoLL is extremely difficult to accurately assess, particularly if a single figure is used to cover the totality of customers. • In addition, it is inherently circular since VoLL and LoLE are correlated - a given value for VoLL implicitly defines LoLE (indeed, VoLL is often back-calculated as the number necessary to maintain the existing LoLE standard). Furthermore, if the value of LoLE implied by the chosen value of VoLL is different from the security standard used to determine the quantity of capacity required, then the market will receive conflicting signals. • The inherent uncertainty and circularity in Method 1 is unlikely to produce the correct capacity price signal and customers will either experience a security of supply below what it should be, or they will have to pay more for unnecessary capacity.	As was suggested in the consultation document, determining the 'true' value of lost (unserved) load (VOLL) is problematic and although in a perfectly competitive market VOLL should represent the willingness of consumers to pay to ensure continued load, no consumer has an identical willingness to pay. The RAs agree that there is a correlation between VOLL and LOLP. If the spot price was allowed to reach a 'true' VOLL, and thereby in theory result in generation adequacy, uncertainty of capacity adequacy may still prevail due to the unique nature of the commodity 'electricity.' Firstly, electricity cannot be stored therefore supply and demand must match simultaneously throughout the day. Secondly, the pattern of electricity supply and demand fluctuates considerably throughout the day and over the course of a year. Thirdly, the electricity system must be in physical supply and demand balance at every point on the network continuously to meet physical constraints of voltage, frequency and stability. In addition the fundamentals underpinning the operation of the electricity market are far from perfect. The combination of these distinctive characteristics helps define the role of generating technologies in the electricity market as each plant is characterised by a set of capabilities and broad definitions that allow it to respond, either significantly or in a limited way, to changing supply and demand requirements. Attempting to reflect the uncertainty inherent within electricity generating technologies is calculated using the probability that load may be lost by any plant type at any time, or Loss of Load Probability (LOLP). LOLP is intended to take into consideration the quantity and mix of the available capacity in relation to the forecasted load and the probabilities of forced outages and is defined as the probability that, at any particular time, demand will exceed available generation. As a result LOLP may also be considered an expression of generation adequacy and is correlated to VOLL.

VPE	We do not agree that the first method, using VOLL and the security standard to derive the value of capacity, is a valid approach in any circumstances. The security standard cannot determine the value of capacity without reference to the balance between benefits and costs, and any attempt to do so introduces a high degree of subjectivity and results in a wide range of possible output values. It is for the market / customers to determine the maximum price they are prepared to pay to avoid disconnection, and for the plant development market to decide what the delivered cost of capacity can be. These two components then determine the appropriate value for the security standard against a failure probability criterion. A reverse solution cannot deliver a practical valuation of determinate value and is against the basic principles of market economics.	As was suggested in the consultation document, determining the 'true' value of lost (unserved) load (VOLL) is problematic and although in a perfectly competitive market VOLL should represent the willingness of consumers to pay to ensure continued load, no consumer has an identical willingness to pay.
	Methodology 2	
SYNERGEN	The assumed costs should be broken down in more detail, presented to participants and open for consultation; and There should be demonstration that for a BNE peaker all costs are covered through the CPM or SRMC based bidding (plus reasonable assumptions on other pool revenues). This should include a specific breakdown of all the costs and technical capabilities between: ▪ output and efficiency characteristics, taking into account ambient conditions across the year ▪ the BNE cost base; ▪ pool revenues under the SRMC bidding principles.	Cost breakdown is addressed Output, efficiency and cost characteristics are detailed Assessing the energy revenue a BNE peaking plant might expect to make is modelled taking into account the BNE peaking plant's position in the merit order based on a full assessment of its underlying costs and adherence to SRMC bidding principles.

ESBI	ESBI's experience indicates that the RAs' figures understate the capital costs and overstate the output of an OCGT based on an ABB 13E2 under Irish conditions. The annual cost estimate does not identify what is included or otherwise, which makes it difficult to form a judgement on how representative the estimate might be.	The performance of a gas turbine, both in terms of output and efficiency, is predicated by choice of fuel and ambient conditions. For the purposes of the BNE, it is assumed that the primary source of fuel is natural gas and the plant is operating at ISO conditions, however this maybe reassessed as per consultation paper. On this basis, the RAs have revised the assumptions used and propose to employ an as-new net power output of 177 MW and an as-new net efficiency of 36.3%. The RAs have adjusted the as-new characteristics of the BNE peaking plant to take account of the degradation in performance over time. The output degradation is assumed to be 0.97 whereas the efficiency degradation factor is assumed to be 0.98. The applicable values for output and efficiency are therefore assumed to be172 MW and 35.6%, respectively. Since publishing the first consultation document, the RAs have revisited their initial capital cost estimate to take account of recent changes to international prices for gas turbines. For the purposes of deriving the BNE peaking plant in 2007, it has been assumed that the plant and equipment costs €70 million which includes an allowance for shallow connection costs to the electrical and gas transmission networks.
ESBPG	As technologies improve the annualised cost of capacity falls, taking all factors into account the annualised cost of capacity of the GT13E2 has fallen from ~ €90/kW/y to ~ €75/kW/y over the last 15 years. The NEPP calculation must take account of this.	The BNE price will be revised annually and therefore any improvement in performance or change in capital cost will be captured in subsequent decision papers.

ESBCS	ESBCS considers that some modification of this method may be necessary to mitigate the level of subjective judgement required and the implementation effort required. ESBCS suggests two possible options: don't deduct forecast energy and ancillary services revenues and determine an index to apply to the determined fixed costs each year for a period of 5 years: i. subjectivity is reduced and stability is increased; ii. implementation effort is significantly reduced with a major review only required e.g. every 5 years; iii. there is a risk of "double-paying" generators however the "infra marginal energy and AS revenues" could be treated as a market incentive to encourage entry and arguably the overall investment signal is not biased in favour of exit at the expense of a dampened entry signal; introduce an annual k-factor to correct in the subsequent year for any over or under estimates of energy and AS revenues based on outturn SMPs: iv. this would remove the fuel price forecast error component for the calculation over a reasonable timescale; v. however, the implementation effort would be increased on an annual basis.	If a CPM was based on the capital costs of a BNE peaking plant without taking into account infra marginal rent earned in the energy and ancillary service markets, over compensation would occur as the CPM would be based upon the fixed cost of a peaking plant that primarily provided only reserve and was wholly compensated for that provision only by the CPM. In reality compensation will also occur through activity in the energy market and the ancillary service market, if this is not taken into account, the CPM will over compensate all generators. A correctly operating CPM should provide sufficient market incentive to encourage entry and facilitate exit in line with market requirements. It is not clear how the application of an index to fixed costs would remove subjectivity as the index rate to be applied would be subjective. Correcting revenue ex post would distort the CPM and fail to fully reflect the capacity requirement of the market going forward. The RAs accept that any fuel/energy price forecast will carry a statistical uncertainty. However the link between fuel prices and the calculation of SMP will remain relatively constant – higher fuel prices will lead, all things being equal, to higher SMP. Therefore the assessment of energy market operation of a peaking plant will also remain constant even though its variable costs will increase in line with fuel prices.

NIE	The estimate of the cost of capital seems low. A real rate of less than 8% is more appropriate to a regulated network's price control rather than a competitive generation plant. The equity beta, while apparently high at 1.8, is not so in the context of 70% debt finance. The asset beta is only 0.54. 10-12% would be a more commonly accepted estimate of the real cost of capital. The plant is assumed to be new and to be more efficient than existing peaking plant. This implies that there is technical progress and the plant's earnings will decline over time. This effect is normally modelled by adding the rate of technical progress to the cost of capital. Truncating the period of the return from 25 to 15 years has the effect of adding 2%-2.7%[5] and so there may be no need for a further addition, but there may be an element of double counting since generation cost of capital numbers are often quoted in the context of periods that are already truncated. It would be prudent to assume a 12% WACC.	The RAs are not persuaded that a peaking plant in the SEM would face more systematic risk than a baseload plant. This is largely because of the design of the market. The RAs deliberately chose to include a capacity payments mechanism in the design, and one with a significant degree of certainty over when and at what price available capacity would be paid, to encourage entry and the retention of plant on the system. A peaking plant's revenues/returns will therefore be no more variable (relative to the state of the economy) than that of a baseload plant in the SEM. They might be in an energy-only market, but the SEM is not an energy-only market. In this regard, the RAs believe that 7.83% is appropriate for the purposes of deriving the BNE peaking plant in 2007.

[5] Depending on the size of the cost of capital.

VPE	The paper assumes that natural gas will be used as the fuel for the unit. However, unless a peaking generation facility is built alongside an existing operational gas fired generation facility or as part of a far wider generation portfolio (which in either case would preclude its definition as a "New Entrant") VPE considers it to be entirely inappropriate to contemplate the use of natural gas for this type of duty because the small number of operating hours simply do not justify either the significant capital expenditure on gas connection infrastructure, or the high fixed costs of reserving gas transportation capacity. Unless the current authorisation prescription is changed by the Regulatory Authorities then it will be necessary for the BNE Peaking Plant to be assessed on the basis that it will be provided with full gas and oil dual firing capability (including the facility for on-site oil storage and the means to achieve NOx suppression through water injection where appropriate). This will result in material additional costs to the construction costs noted in the Consultation Paper. To keep the plant available, a gas option would have to be bought forward to ensure that gas was available if needed. In most days, it would not be required and so the cost of the option would have to be born by the peaking plant operator. The cost of buying daily forward options needs to be included in the fixed cost of operation, and the added risks associated with this included in the assessment of WACC; To access the gas system, the generation facility must incur the BGE fixed gas transport costs. The unit cannot be said to be available if it does not have the capacity available instantaneously to be supplied with gas. This would add more than €60/kW pa to the fixed costs of the unit;	The costs of the annual gas capacity charge is high – the cost of gas assumed in the paper did not include the full gas capacity charge. In RoI the annual booked capacity may be traded on the secondary market – although the extent to which this is possible depends on liquidity. In NI the secondary market is extremely limited. The RAs are seeking views on this particular issue. The RAs recognise that the additional costs of water injection and fuel storage for a single liquid fuel need to be considered in the light of newly proposed gas transmission costs and additional gas compression plant for natural gas firing. The present capital cost estimate includes allowances for both natural gas and liquid fuel. The overarching assumption is security of supply and the need for dual fuel capability which is subject of an ongoing consultation by the CER. The RAs will clarify these issues in the forthcoming decision document.

	Methodology 3	
ESBPG	Methodology three is not appropriate for the SEM as it assumes new entry will not be merchant entry rather under terms that reduce the risks to the plant and therefore the required WACC. In order for the SEM to operate successfully all entry should be assumed to be merchant and therefore requiring a market WACC.	See above comments
BGE	We believe that the basis for the proposed discount rate should be an appropriate level of WACC for a peaking plant (on the basis that the plant may be built with private funds?) and the appraisal should be based on a plant's economic rather than its book life. Alternatively, the discount rate could be based on long-term borrowing rates for 10-15 years. Therefore, the main benefit of this approach is that the peak unit price could be fixed for, as a minimum, for 5 years and potentially up to 10 years. Alternatively, the cost could simply be indexed to a suitable manufacturing index for a period of 15 years. We propose that under this approach any periodic reassessment of costs is awarded to reputable independent engineering consultancies.	See above comments and note the RAs intention to reexamine the BNE peaking plant cost on an annual basis from 2008.
	Appendix 1 – Technology Options	
ESBI	The ABB 13E2 is stated as having a net output of 180MW and net efficiency of 36.9%, but this is the gross output of the machine at ISO conditions. ESBI's modelling indicates under Irish conditions the net output would be around 172 MW at a net efficiency of around 35.6%. These are both 'as new' figures typical of design conditions, plant suppliers will usually only guarantee performance slightly lower than this and lifetime degradation would reduce this by another couple of percentage points.	See above comments

ESBPG	*While PG have not undertaken a detailed technical review of the figures in Appendix 2 an initial review has raised the following issues* ▪ The output of the GT13E2 is 180MW gross but the Alstom website quotes a net figure of 172MW. The ROI BNE uses net figures. ▪ The efficiency quoted (36.9%) is gross and does not have any degradation factor. A more accurate new full load net efficiency would be 35.68%. The ROI BNE applies a degradation factor of 0.98. Applying this factor gives a net efficiency of 34.96%.	See above comments
NIE	The capacity increment used is too large and limits the choice of new entrant peaking plant to a very limited number of options if the economy of scale in plant size (i.e. single unit) is to be captured. A key issue in the selection of the appropriate technology is also the requirement for fast start capability (i.e. 5-10 minutes) which is a key role of peaking plant and the requirement for which is likely to increase as the penetration of wind generation increases. The issue of the fuelling is unclear. If the capacity is to be gas fired, the capital cost must reflect the gas connection and gas control costs. In addition, gas fired plant is currently required to have the capability to operate on a back-up fuel. This will also increase the capital cost (plant capability and fuel storage and handling).	See above comments
PPL	Full load efficiency is used to calculate the marginal cost of an 180MW Unit. In reality the fixed energy costs are relatively high on Open Cycle Gas Turbines (OCGT's) and variable costs are relatively low. In other words the part load efficiency of the machine will be considerably less than full load efficiency and part load dispatch is therefore unlikely (or a higher bid price required). This would considerably reduce the number of hours that the BNE Unit could earn revenue from Energy Market.	The RAs have assumed that the peaking plant will be dispatched at full load for the relatively few number of hours that it will be required to run.

BGE	By definition a peak plant will be used at low load factors and therefore the efficiency itself will have a limited impact on carbon emissions. Other emissions such as NOx and SOx may be more important in assessing what constitutes the best available technology. Furthermore, the overall environmental cost in use over the plant lifetime should be considered. For example, a rarely used lower efficiency machine running at low load factors may require less materials to construct, and hence have lower overall lifetime emissions. We believe that a smaller unit is more appropriate for the all-island SEM given its size. Arguably, three 72MW units would offer greater capacity reliability and system flexibility than one 180MW unit. Investment Costs Certain costs appear to be underestimated. ▪ While the proposed BNE peaking plant has 45% of the installed capacity of a 400MW base load plant, certain cost would be expected to be largely fixed regardless whether a 180MW or 400MW plant is built. In particular, this would apply to development costs such as environmental impact assessment, legal, financing, engineering, etc. ▪ The site procurement cost appears to be under estimated versus the equivalent base load plant. Operating Costs ▪ Gas transportation capacity costs appear to be missing. Transportation capacity costs for a peaking plant are expected to be higher than for an equivalent base load plant. Discount Rate ▪ A higher discount rate may be appropriate for a peaking plant than for a base load plant due to its higher inherent risk. This is because the majority of the peaking plant revenue is derived from capacity payments which are volatile based on annual capacity requirement.	A more comprehensive explanation of the approach employed to select the BNE peaking plant is provided in this consultation document. The rationale for choosing a notional 180MW takes account of the appropriateness of size relative to the interconnected system whilst ensuring certain economies of size minimise the specific capital cost of the BNE. See previous comments

VPE	While the paper lists the criteria used in choosing the type of unit, these are not defined, nor are there any details which show why some of the GT types have been rejected. To help in understanding the selection process, the role of the peaking unit, (including system support, start times, wind support etc) needs to be set down in more detail than is included in the paper because the costs and characteristics of the selected plant is subject to far more variables than would be the case for a "base load" BNE plant. To determine the preferred practical choice of the best new entrant peaking facility, a more detailed technical and economic analysis needs to be carried out of each plant type that might be expected to be available. This then needs to be set against the full requirements that have been derived from the expected role of the peaking unit.	On the basis of least cost, the RAs are of the view that the best new entrant plant for the CPM should be based on a large open-cycle heavy duty industrial gas turbine. Section V of the paper examines this in more detail.

	Appendix 2 – Derivation of Costs	
ESBI	***Investment Costs*** It is not clear whether the capital cost includes the €3m or so that the developer would be charged by the gas transporter for the above ground installation (AGI). The budget would also have to include €2m for a gas compressor (plus 100% standby) as Irish pipe-line pressure guarantees tend to be lower than the inlet pressure required by the 13E2. The assumption in the Methodology Three costings that the plant is constructed on "*land already owned by the TSO and therefore site procurement costs are zero"* does not appear to be consistent with the suggestion elsewhere that the plant might be located in the south, i.e. in RoI and thus owned by EirGrid. Since the latter is a system operator rather than an asset owner it would have to purchase the site, unless the RAs are proposing that ESB own the site, in which case there should be an imputed rent included in the fixed annual cost. If the plant were to be built in NI, then the same would presumably apply once SONi is separated from Viridian Group. ***Fixed non-fuel operation costs*** An open cycle gas turbine would not normally be maintained under a long-term service agreement, which are more typical of base-load CCGT. It is not clear whether the general and administrative costs include SEM-specific costs such as licensing, SMO fixed costs, etc. Fixed transportation costs account for a very high proportion of Irish delivered gas costs, which does not appear to be taken into account and it is not clear how the plant would be staffed. ***Variable operation costs*** Gas turbine operation and maintenance costs are shown per kWh without any reference to the additional cost per start which would be levied on the owner and which can vary depending on the type of start, ramp rate, etc.	All costs for the project have been taken into consideration. See section VI of the consultation paper for non technology specific cost breakdown decision.

ESBPG	▪ It is not apparent that a contingency has been added to the EPC costs. The ROI BNE uses a contingency of 5%. ▪ There is no annual cost for Gas Capacity. If the Peaker were to purchase gas capacity to allow it to run at full output for a full day it would cost about €9 million. This should either be included in the costs or the unit should be assumed to run ion distillate.	A contingency of 3% has been applied to the EPC cost. The paper considers & seeks views on whether gas capacity charges should be included as a fixed cost.
NIE	The cost of the peaking plant should be comprehensive. It must include all connection charges, commissioning costs, the cost of reserving gas pipeline capacity, fuel stocking costs for backup fuel, TUoS charges, TSO charges, MO charges, licence fees etc. It is not clear that this has been done.	All relevant capital costs have been included in the BNE price model. Including all those listed.

PPL	Based on PPL's knowledge, Capex of E394/Kw seems low. A recent PB Power report to Institute of Chartered Surveyors suggests E495/Kw as reasonable. Should the revised (harmonised) Grid Code require a dual fuel gas fired plant (as seems likely) Capex will increase. WACC of 7.83% is based on a corporation tax rate of 12.5% compared to UK's 30%. The paper infers this is because BNE Plant would be built in RoI. This adversely impacts NI generators and seems unfair as the CPM is designed to reward capacity in both jurisdictions. An assumption of 5 days planned outage per year is optimistic. While the BNE Plant is unlikely to incur significant running hours scheduled Hot Gas Path Inspections and Major overhauls are required. Generally Original Equipment Manufacturers do not advocate an interval frequency beyond 5 to 6 years in spite of the Equivalent Operating Hours (EOH) (although EOHs will be increased by a large number of starts). In PPL's opinion an assumption of 13 days planned outage is more realistic. An assumption of site procurement costs of €1.4m is considered low given the likely competition for strategic sites and soaring retail values.	Capex costs have risen since the publication of the previous consultation. The current BNE peaking plant figure is €473/Kw which includes dual fuel capability. Based on current system dynamics and subsequent locational signals, gas connections costs, gas capacity charges and tax a BNE IPP peaking plant would have sited in ROI. The fact that ROI has a lower WACC is a function of the differing tax regimes north and south which is beyond the remit of the RAs. After technical review, 13 planned outage days has been included in the BNE price derivation for the Alstom. The RAs have reviewed and revised the site procurement costs to €2.5 million.

Airtricity	The derivation of costs does not address the additional costs which generators will incur under the SEM and which are not included under the existing BNE methodology. These include:
	
	• SMO Tariff Charges
	  o Generator Testing Charges
	  o Market Operator Charges
	  o Currency Charges
	• Accession and Participation Fees
	• Administration associated with bidding principles and Market Monitor
	
	The WACC figure applied to a base load plant may not be appropriate for a peak plant. This is because the majority of the peak plant's revenue is derived from CPM, which is volatile based on annual capacity requirement and additional regulatory risk. A higher WACC must be applied to peak plants.
	
	Capital Costs
	It is noted that although the peak BNE plant has 45% of the installed capacity of the base load BNE plant. The table below shows the percentages of the various capital cost categories given for the peak plant versus the base load BNE plant.
		An estimation of Admin costs have been made for the BNE peaking plant. See previous comments and section VI of the consultation paper.

VPE	**WACC** – the parameters that drive this are all taken from the recent BNE 2007 pricing paper, which have been presented as being appropriate for a base load CCGT in the RoI. However, a peaking gas turbine servicing the whole of Ireland is likely to have a higher WACC for two reasons; ▪ Firstly, as mentioned above, if the unit operates on gas, the operators will have to buy gas forward to be sure that it has gas available. It will also have to ensure that it has sufficient carbon credits. As the actual running of a peaking unit is much more uncertain than that for a base load CCGT, all of these factors increase the risks associated with the costs and income of the peaking unit. This should be represented by an increase in the equity beta in the WACC calculation. Our assessment suggests that the current value of 1.83 should be increased to at least 2.0; ▪ The second reason is the assumed tax rate. The Republic of Ireland has a significantly lower tax rate than all other major western economies, including the UK. With the introduction of the SEM, we now have to consider the tax regime in Northern Ireland as well as the Republic. If a non RoI company were to build a peaking unit in Ireland then it will end up paying its home base rate of tax on repatriated dividends, even if the tax rate in the RoI is significantly lower. Using the RoI corporation tax rate therefore biases against non RoI developers and over time will significantly reduce competition in this segment of the electricity market. The tax rate should then be set to that which is representative of the major western economies and 30% is considered a more reasonable value. ▪ **EPC Costs** – we have reviewed the EPC costs for a 13E2 for both the gas only option and when dual fuel capability is included – the latter includes distillate and de-mineralised water storage and also filling the tank with a working stock of fuel. We consider that the value in the paper is too low for either option. Our estimates would put the cost at €65m for the gas only option and €70m for dual fuel use. For a broadly comparable Trent aero derivative package with 3 units and dual fuel capability, the CapEx is estimated to be €85.5m for 155.7 MW of net sent out capacity. ▪	See previous comments and section VI of the consultation paper

	Appendix 3 – Derivation of Infra Marginal rents	
ESBPG	Wile a peaking plant may make a pool surplus in its initial years of operation this should quickly be eroded either by the entry of other similar technology peaking plant or by improvements in peaker technology. To assume that the peaker will make pool surplus for 15 years is unrealistic. The heat rate of the GT13E2 has improved by 5% over the last 15 years, meaning that a 15 year old GT13E2 would not be recovering any pool surplus. PG cannot replicate the calculation of the revenue from the Ancillary Service (AS) market as the assumptions underlying the calculation are unclear. It should be noted that an increase in Size of Peaker plant will not necessarily result in a proportional increase in reserve supplied to the system. PG request that the RAs carry out a more detailed calculation of the AS income prior to determining the NEPP cost to be adopted for the SEM.	Degradation of plant performance has been taken into account in the paper. The Alstom has as-new net efficiency of 36.3 per cent (lower heating value) but this has been reduced to 35.6% to take account of the degradation in efficiency over its lifetime of operation. Ancillary Service estimates will be derived using current ROI AS rates given the location of our BNE peaking plant. This is described in more detail in section VII of the paper.

NIE	As previously stated the inclusion of the infra-marginal rent implies technical progress and a return that will decline over time. We think that it would be better to exclude the item altogether. As time goes by, it is likely that the cost of peaking plant will continue to reduce thereby resulting in a lower capacity cost than is necessary to remunerate the plant over the financing period. Similarly, the efficiency of the next new peaking plant built is likely to be higher and hence reduce any infra-marginal earnings. Any upside in the early years is likely to be offset by losses in the later years of the plant's operation. It may be argued that the cost of peaking plant may not fall or that efficiencies will not continue to improve. However, this will create a risk that will compromise security of supply (by delaying the efficient construction of new plant and thereby increasing the capacity payments). The solution is either to ignore any contribution from infra-marginal rent or else to increase the WACC to reflect this additional risk. Ancillary Services in NI are based on a payment of 50p/MWh of plant availability. With 92% availability, this amounts to circa €5.6/kW before deductions are taken off for rebates (failure to deliver). This is much less than the €9.68/kW quoted in the paper. It should also be noted that this difference in value also appears to contradict the statements in the consultation paper (AIP/SEM/96/06) and decision paper (AIP/SEM/160/06) which considered the Day 1 Ancillary Service arrangements and indicated the level of payments for these services in N. Ireland and RoI are broadly equivalent. On the basis of the figures used in this paper and the actual payment rates for System Support Services in N. Ireland, this is clearly not the case and the deduction of the higher RoI based figure would discriminate against N. Ireland generators.	As mentioned above the degradation of the plant's efficiency has been taken into consideration within the paper. At present there is little evidence to suggest that the cost of peaking plants will decrease over time or that efficiencies will dramatically increase. In the case of the former the opposite is the true, since the publication of the first BNE consultation and this paper the capex cost of a peaking plant has actually increased by appox. 20%. The RAs have conducted detailed costing analysis in determining an optimal BNE peaking plant including AS arrangements. The RAs are committed to harmonising AS arrangements in both jurisdictions and detailed work is ongoing to address this issue.

	A peaking plant will run for short periods of time. When dispatched on, the plant must also recover its start-up and no-load cost in the SMP. The design of the uplift mechanism will cause an increase in the SMP during the hours the plant is dispatch which must be sufficient to cover its start up and no load costs. In effect the peaking plant will usually just break even during each period of continuous operation. Given the design of the uplift mechanism it is unlikely that any material infra marginal rent will be eared above the marginal cost of the unit plus start up costs. None of this is considered in the consultation paper. Other factors concerning infra-marginal rent are also ignored. A 180 MW peaking plant, or perhaps several will be dispatch on in the hours identified with high SMP. The fact that these units will be dispatched on will mean that it is less likely that there will be units on system with a higher SRMC to set a high price. In effect the existence of the plants will destroy the prices visible in the market before they are built. Also, during peak days gas prices may well be in excess of gasoil prices, therefore there would be a change in the merit order and this will cause a further reduction in the likelihood of infra-marginal rents to the peaking gas plant.	The RAs note that the design of the uplift mechanism as set out in consultation AIP/SEM/230/06 does not preclude the possibility of the BNE peaking plant from making infra marginal rents from the Uplift mechanism per se. The RAs will be investigating the potential infra marginal rents earnings from the SMP through the methodologies set out in section VII of this paper. In the underlying theory we assumed that the market is in equilibrium, having established this principle we are interested in establishing the infra marginal rent resulting from the current competitive equilibrium and not an artificial scenario whereby the SMPs have been dampened. Validated assumptions will be made surrounding fuel prices in loop 3 of the plexus run which will set the indicative running schedules for the BNE peaker.

	Net Energy Income – we concur with the view expressed in the paper that this is very difficult to forecast. However, we believe that the approach used in the paper is too simplistic for two major reasons: ▪ Firstly, it is not sufficient to just look at the number of trading periods when the market price is expected to be above that of the peaking unit. With the size chosen of 180 MW, it is a major perturbation to the merit order and so would significantly influence the price during the periods when the current price forecasts are above the cost of the peaking unit. Our assessment indicates that this would substantially reduce the net income from the energy market. This assumption is of course for the use of gas. If distillate is used, then there would be little or no net energy income; ▪ Secondly, the view taken in the paper is only valid for next year. In time, as new peaking plant are brought on line to provide the necessary capacity for retired plant and increases in demand, the current plant will operate less and less and its net energy income will degrade significantly over time.	As outlined above, If we go back to the underlying reason for using the CPM approach, we are attempting to calculate the amount of money that a competitive energy market in equilibrium would need to recover over and above SRMC-based prices, in order for the BNE peaker to just break even. The efficiency set out in the paper takes account of degradation.

	Ancillary Income – we have a major concern about the inclusion, within the BNE capacity value evaluation, of income based on payments for reserve. Under the proposed SEM principles, any plant on the system (including a new peaking unit that is available but not running) will qualify for the capacity payment under the current CPM proposals. They will also qualify for the Eirgrid “Replacement Reserve” payment. Provided the receipt of <u>both</u> payments is confirmed as applicable under the market rules, and the level of payment currently applicable to Replacement Reserve is guaranteed to be maintained going forward, then we would agree that these reserve payments should be taken into account for the purposes of calculating an appropriate level of fixed capacity income for the BNE peaking facility. However, it is possible (indeed likely) that this will not be the case because Replacement Reserve is only payable when the unit is NOT operating, and this implies that the capacity value of a MW that is in reserve is greater than that for a MW that is actually delivered to the system. There can be no distinction between the value of operating and reserve capacity, and so the payment for replacement reserve should arguably be covered in the CPM capacity payment rather than being separate. If there were a difference in the value of operating and reserve capacity, then it could lead to units that are at or near the margin to bid an elevated SRMC to reflect this inequality since avoided dispatch would lead to additional reserve income. This mechanism would have the overall effect of increasing the SMP, which is clearly an undesirable outcome. In addition to this, if the replacement reserve income is included in the calculation of capacity income, then it will be necessary to ensure that the calculation is in accordance with the current Eirgrid rules. VPE has assessed the replacement reserve income, that might be payable using the current rules, and the value of the reserve income is much less that the €9.68/kW pa set out in the Consultation Paper. VPE estimates reserve income under SEM conditions to be in the region of €1 – 3/kW pa,	The AS arrangements for day 1 will include Replacement Reserve payments. This issue has been previously identified and is being considered by the RA’s Ancillary service work stream. A detailed analysis on reserve revenue estimation will be conducted in accordance with Eirgrid’s methodology and 2007 rates once technology choice has been decided upon and when running hours of the BNE peaking plant have been established.

	depending on the required level of replacement reserve and the plant that is available but not running. For the purposes of this Response Paper we have included €2/kW, as an estimated value for Replacement Reserve, as a receivable income within the calculation because this is the simplest way to deal with the situation at this point in time. However, it must be recognised that the income it represents is a required portion of the income needed by a real world peaking unit to become a justifiable investment proposition, and if Replacement Reserve payments were to become smaller or no longer permitted under the future SEM structure, then an amount corresponding to the reserve payments foregone needs to be added back into the BNE Peaker calculation.	The RAs will be using Eirgrid's methodology for deriving AS payments for 2007.
	Other comments	
PPL	Once a methodology is decided upon and assumptions agreed there should be limits regarding the frequency and extent of changes. This would dampen volatility in the CPM revenue stream thus providing more certainty for long term decision making.	The RAs are committed to delivering a robust methodology that sends efficient investment signals.

VPE	The Emergency Generation peaking facilities which are owned and operated by ESB Power Generation, following their prior assessment of the appropriate security requirement, have been approved, designed and installed to operate on distillate gas-oil only; One of the most potentially advantageous aspects of OCGT peaking facilities is recognised to be their ability to support and facilitate the further expansion of renewable energy by providing fast responding and flexible power output to correspond with the unavoidable variations in wind powered electricity output. It is largely the case that network locations with the highest propensity for wind development are those areas with little or no access to gas supplies; A primary function of a peaking installation would be to provide support to the power system in locations prone to voltage or reactive power variations arising from their remoteness or other power system restrictions. Such locations are almost invariably distant from a practical supply of natural gas; If a peaking installation is to provide the incremental security needed to assure continuous supplies during periods of potential shortfall, then it is imperative that the source and ready availability of the fuel is secured and immediately available for use. On site oil storage is by far the most practical and economic means of achieving this.	Clause 6 of CER's 'Authorisation to Construct' a power station contains a requirement for dual fuel capability at a generating unit. For the basis of this paper it is assumed that the notional peaking plant will be compliant with this requirement and that its primary fuel source is natural gas. However, the RAs will reassess fuel choice with reference to the relevant dual fuel requirements in place in ROI prior to publication of the final number and in light of responses received on the liquidity of the secondary market for gas capacity and of new BGE capacity booking arrangements.