Single Electricity Market

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

Final Decision Paper

18th May 2007

AIP/SEM/07/187

I. INDEX

II. SUMMARY OF DECISIONS

- The chosen technology for the BNE peaking plant upon which the price element of the Annual Capacity Payment Sum ($APCS_y$) for 2007 for the Capacity Payment Mechanism (CPM) will be based upon a distillate running Alstom 13E2 with a notional lifetime net plant output of approximately 182MW.
- The fuel choice for this BNE peaking plant is to be solely Distillate.
- The unadjusted BNE peaking plant annualised fixed cost for 2007 is €85.04/kW/yr
- The preferred methodology for deducting the inframarginal rents is Methodology 2 b) utilising two Plexos runs to establish firstly a commitment schedule and secondly a calculation of the rents.
- The estimated annual inframarginal rent earning for the BNE peaking plant from the energy market for 2007 is €14.19/kW/yr
- The estimated annual revenue earned from Ancillary Service arrangements by the BNE peaking plant for 2007 is €6.12/kW/yr
- The total deduction to be made from the unadjusted BNE peaking plant annualised fixed cost is €20.31/kW/yr
- The final adjusted BNE peaking plant annualised fixed cost for 2007 is **€64.73/kW/yr**

III. INTRODUCTION

On 13th February 2007 the Northern Ireland Authority for Energy Regulation and the Commission for Energy Regulation ("the Regulatory Authorities") published a consultation paper entitled *"Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism, Decision and Further consultation Paper"*[1]. The paper set out the Regulatory Authorities preferred methodology for estimating the price of peaking capacity in the SEM for the purposes of setting the annualised capacity pot (known as the Annual Capacity Payment Sum – $ACPS_y$) for the Capacity Payment Mechanism (CPM). The document also provided decisions in respect of a number of revenue and cost assumptions.

In addition to the above the document also sought further views on the technology options outlined in the paper, the implications of new shorter term gas capacity products, the liquidity of the secondary gas capacity market and methods for deriving an estimation of infra marginal rents.

Comments were invited on these methodologies and the other issues set out in the consultation document by 13 March 2007. Responses were received from seven organisations and the non-confidential elements of these responses were published on the AIP website on 3rd April 2007.

This paper sets out the Regulatory Authorities responses to the comments received and presents the conclusions of the Regulatory Authorities in the matters addressed by the consultation.

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1 http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=3a72c290-e714-42ee-97b3-4c8ff691f42e

IV. BACKGROUND

In July 2005 the Regulatory Authorities set out the High Level Design Principles of the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM). In the High Level Design Principles the Regulatory Authorities indicated their proposal to develop a fixed revenue capacity payment mechanism that would provide a high 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 Regulatory Authorities 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 Regulatory Authorities. 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 as well as setting out the processes that the Regulatory Authorities proposed for determining the Annual Capacity Payment Sum and the general process by which it was proposed that input parameters for the CPM would be set.

In relation to the matter of determining the Annual Capacity Payment Sum, the March 2006 paper proposed that the sum should be set by multiplying an appropriate level of required generation capacity (the Capacity Requirement) by the relevant fixed costs of a Best New Entrant (BNE) peaking generator. The costs of such a BNE plant would be expressed in €/kW per year (as an annualised payment) and 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 September 2006, the Regulatory Authorities published a consultation paper setting out a number of matters for consideration in the determination of the fixed costs of a BNE peaking generator. Responses to that consultation broadly supported Methodology 2 for determining the cost component of the annual fixed sum, however some reservations were expressed over fuel choice and the treatment of gas capacity charges, technology choice and the methodology to account for infra marginal rents and Ancillary Service market revenues.

The Regulatory Authorities published a decision and further consultation paper published on 13 February 2007 which considered these issues and section VII of that document examined options for deriving both the energy and ancillary service rents a BNE peaking plant might expect to earn in the new market. This paper concludes on the technology choice, fuel choice and the methodologies to be employed in calculating both the Energy Market and Ancillary Service revenues and presents the final figure to be used as the price element in determining the Annual Capacity Payment Sum for 2007.

V. TECHNOLOGY CHOICE

Section V of the further consultation document identified that there are relatively few commercially available gas turbines from which to select a BNE peaking generator on which to base the price calculations for the CPM. The document identified that of the six commercially available units, two failed to meet criteria associated with start-up time and a proven track record.

The remaining four units were subject to screening curve analysis to compare the generation costs. This analysis resulted in the exclusion of a further unit leaving three units for consideration. With all three units having met the criteria and having similar generation cost characteristics, the Regulatory Authorities referred to the Integrated Pollution Prevention and Control (IPPC) directive relating to Best Available Technology which considers unit efficiency. Based on this criteria the Alstom 13E2 was identified as being the most appropriate technology upon which to base the BNE peaking plant.

No comments were received relating to the specific technology proposed in the consultation document and therefore the Regulatory Authorities have determined that the BNE peaking generator for 2007 shall be based upon the Alstom 13E2.

One comment was received regarding the possibility for technology choices to change from year-to-year, either as a result of new machines becoming available which are able to better meet the Regulatory Authorities selection criteria or as a result of the Regulatory Authorities changing their criteria. The specific concern raised was that this could result in investment in mid-merit or peaking plant being stranded.

In undertaking two consultations on the BNE peaking costs the Regulatory Authorities have recognised the importance of establishing a repeatable, mechanistic process through which the fixed costs of a BNE peaking generator can be determined. It is not therefore the intention of the Regulatory Authorities to change the criteria against which technology options will be assessed in the future unless a clear reason for doing so emerges. Nonetheless as the respondent identifies it is possible for the technology choice to change in future years as improved units enter the market, although a period of sustained operation of any new technology would be required before it could be considered for selection as the BNE peaking plant given the need to meet the “proven track record” criteria. However the Regulatory Authorities consider that this is an underlying market risk which would exist anyway, even if the market were an energy only market, and therefore no further action is required.

Operational Performance

Having identified the technology upon which to base the BNE peaking plant a number of further technology related matters need consideration. These are set out and addressed in the following sub-sections.

Efficiency

For an OCGT plant, the Regulatory Authorities consider a reasonable plant efficiency degradation factor to be 0.97. One respondent suggested that a factor of 0.96 would be more appropriate based on their industry experience however the advice provided to the Regulatory Authorities by the specialist employed to assist in the determination of the BNE costs indicates that 0.97 reflects efficiency rates being currently quoted by leading manufacturers. Thus, the Regulatory Authorities have employed a 'lifetime' mean operational efficiency of (0.97 x 34%) = 33.3% net which gives a notional lifetime net plant output for the BNE peaking generator of approximately 182MW..

Planned Outage Duration

The Regulatory Authorities estimate annual planned outages for maintenance for this type of technology and configuration and for peaking operation at 13 days. The Regulatory Authorities consider that this reflects current practice adopted by generators operating in a competitive market environment.

Forced Outage Rate

The Regulatory Authorities expect an open cycle plant of the technology and configuration adopted to have a mature forced outage rate (“FOR”) of approximately 2% per annum.

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VI. FUEL CHOICE

In the consultation paper the Regulatory Authorities identified that gas was considered to be the preferred fuel choice for the BNE peaking generator but highlighted that concerns regarding the gas capacity charges had been raised. As a consequence the Regulatory Authorities sought views from respondents regarding the liquidity of secondary gas trading so as to assess the feasibility of trading out of such charges or perhaps purchasing gas on a short term basis.

A number of respondents considered the liquidity in the secondary market to be low and that there would be difficulties purchasing gas on a short-term basis, particularly at times of system stress. Consequently respondents in general considered that the full gas capacity charge needed to be reflected within the fixed costs of the BNE peaking plant.

The Regulatory Authorities have also investigated the possible introduction of new short term Gas Capacity products by BGÉ in accordance EU directive 1775[2] and have explored the possibility of the BNE peaking plant relying on these products to submit generation offers to the market. Whilst the impact of these possible new products may be taken into consideration in future years, at present there are no short term products currently commercially available and therefore have not been taken into consideration in deriving the BNE price.

Having taken the above information into consideration the Regulatory Authorities have concluded that the BNE peaking plant should be based on distillate fuel. This approach was specifically suggested by one respondent to the first consultation. As a consequence there is no requirement for a secondary fuel source (the dual fuel requirement which currently exists in RoI only applies to gas-fired plant) and therefore the costings which follow in this document are based on distillate running only.

[2] http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32005R1775:EN:HTML

VII. INVESTMENT COST SUMMARY

This section sets out the investment costs used in the determination of the annualised fixed costs of the BNE peaking plant, which in turn is based on the selected technology of the Alstom 13E2. Key comments received on these matters are addressed within the relevant section below.

Breakdown of the Investment costs

Investment costs can be subdivided as follows:

- site procurement costs;
- pre-financial close costs; and
- post-financial close costs:

The estimated cost of each of these is discussed in the subsections below.

(a) Site Procurement

In considering the optimum location for the BNE peaking plant on an all-island basis the approach was to examine the matters which an investor would consider in deciding where to locate a plant. This would include all costs associated with the delivery of the facility and the on-going operational costs. Thus the Regulatory Authorities have reviewed a number of different costs including locational transmission charging, differences in financing costs and site availability. On the basis of the matters considered, the Regulatory Authorities have concluded that the BNE peaking plant should be assessed based on being sited in the south-west region of RoI. This is consistent with the conclusions expressed by the Commission for Energy Regulation in its decision document regarding the 2007 BNE baseload model and with the Transmission Forecast Statement 2005-2011 prepared by Eirgrid.

Investment costs are therefore based on the cost of a plant located in the south-west region.

The estimate of the cost of purchasing a suitable site is estimated to be €2.5m.

(b) Pre-Financial Close Costs

The pre-financial close costs include the Developer's costs, Environmental Impact Assessment (EIA), engineering costs, legal and financial costs. The estimate for such pre-financial close costs amounts to a total of €1.5 million.

(c) Post-Financial Close Costs

The post-financial close costs consist largely of the Engineering, Procurement and Construction (EPC) contract costs, but there are a number of other costs incorporated into this heading too. Further detail on all of these are provided below.

(i) EPC Contract

The estimated cost of the EPC contract is based on the plant configuration discussed previously and budget quotations from EPC contractors with knowledge of these types of machines and construction in Ireland. Provision of €3m has also been made for Selected Catalytic Reduction (SCR) technology within the capex, which will allow the distillate only peaking plant to meet all its environmental and Grid Code Minimum Stable Generation (MSG) requirements.

The estimated cost of the EPC contract price, including contingency, for the type of OCGT plant under consideration is €66.744 million.

In addition the EPC would address connection to the Transmission System. The capital cost estimate for the grid connection is €2.5 million, bringing the total EPC Contract cost to €69.244 million.

(ii) Other Costs

There are a range of miscellaneous costs that would be incurred which have been included under this heading. Estimates calculated as percentages of the value of the EPC contract have been used, based on historical data and experience. These are set out below.

Owner's engineering costs

An allowance is made for project management, engineering and insurance from financial closure to commissioning of the plant. A value of 1.5% of the EPC contract price is used, equivalent to €1.039 million.

Spare Parts

In addition to the above base price, allowance has been made for a reasonable amount of spares, which would be expected to be kept on site to ensure the efficient operation of the station within a competitive market environment. These have been valued at 3.5% of the EPC contract price, amounting to €2.424 million.

Pre-Operation O&M Costs

The up-front cost of O&M mobilisation is estimated to be in the region of €0.350 million.

Interest During Construction

Interest during construction has been calculated based on a 2-year construction period and a Weighted Average Cost of Capital of 7.83%. This amounts to €2.574 million. It is assumed that a disbursement schedule of 90% and 10% in the years Y_{C-1} and Y_C will respectively apply (where Y_C is the year of commissioning).

Contingency

An explicit contingency has been allowed for in considering the Developers costs. A contingency of 2% of the EPC contract price has been included, amounting to €1.384 million

Based on the above, and as shown in Table 1, the total investment cost estimate for the BNE generating plant is €81.015 million. To convert this to an annualised figure a lifetime of 15 years has been employed and a Weighted Average Cost of Capital (WACC) of 7.83% - this latter figure results from the siting of the unit in the RoI. One respondent argued that employing a WACC based on RoI Tax rates would undermine the all-island nature of the SEM through the presumption that all new peaking plant must locate in RoI to make a reasonable return. Another respondent commented that since a peakers' revenue would be more dependent on the CPM than the energy market and the CPM was less certain than the energy market as a result of it being subject to greater regulatory discretion, the Regulatory Authorities assertion that the applicable WACC should be the same as for the BNE baseload plant was incorrect and the risks would suggest a higher WACC to be more appropriate. Other comments received included concerns that the WACC was being calculated using both real and nominal market return, that a gearing ratio of 70% may not be realistic and the potential for fluctuation in

EPC cost in the short or medium term could lend volatility to the BNE price from one year to the next.

The Regulatory Authorities do not consider that employing the RoI Tax rate to determine the WACC undermines the SEM or presumes that new peaking plant must be built in RoI. As explained above, the Regulatory Authorities considered a number of factors in determining the optimum location for the BNE peaking facility so as to identify the site where an investor would choose to site. In sizing the CPM pot the regulatory Authorities determined that a Best New Entrant peaking plant would provide the basis of the price element – this is the most appropriate technology delivered for an optimum price. Having accounted for all the various factors, including the impact of the differences in the Tax regimes, the Regulatory Authorities concluded that an investor would locate in the south-west of RoI. This is having assessed the matter on an all-island basis, consistent with the SEM. If the Regulatory Authorities had selected another, more expensive location upon which to base the CPM pot, anyone building a peaking facility would still site it in the most advantageous position (i.e. in south-west RoI), thus incurring less cost than accounted for in determining the BNE peaking plant (and the CPM pot) and would make additional profit from the CPM. Thus, the Regulatory Authorities consider that in assessing the optimum siting on an all-island basis and accounting for all relevant factors, the decision is consistent with the principles of the SEM.

Regarding the risk profile of a peaker versus a baseload plant, the Regulatory Authorities note that one of the purposes of the introduction of the CPM into the SEM design was to provide a more stable, predictable revenue stream for generators and to reduce some of the volatility in the energy market. The fact that a peaking plant will derive a greater proportion of its revenue through the CPM than will a baseload plant suggests that a baseload plant is, in fact, exposed to a greater risk since its revenue is more dependent on the energy market, payments through which are less predictable and stable than through the largely predictable CPM. It should be remembered that 70% of the CPM pot is allocated in advance of the Trading Periods to which it applies, providing a significant degree of predictability. Whilst there are a number of parameters in the CPM which are established by the Regulatory Authorities, the Regulatory Authorities have established and published methodologies for the determination of many of the variables and for the remaining variables the Regulatory Authorities have stated on several occasions that the values assigned to these variables will not be changed without significant justification and not without careful consideration of the impact of any changes by the Regulatory Authorities.

Given these matters, and the comments raised regarding the market return and gearing ratios used in calculating the WACC, the Regulatory Authorities have had the proposed WACC reviewed by expert independent verification which has concluded that the settings described are credible for the WACC calculation and consequently the Regulatory Authorities do not consider a lower level of gearing or any other adjustment resulting in a higher WACC is necessitated.

Regarding the volatility of the EPC cost, the Regulatory Authorities recognise the potential for variation of EPC costs on a year on year basis, however it is the case that investors would be exposed to these variations in an energy-only market and therefore reflecting such variations within the BNE pricing mechanism is, in the Regulatory Authorities opinion, a reasonable approach. The application of a smoothing mechanism or, as has been suggested, placing limitations on the extent to which the price can vary from year to year could distort the market signals. Some how tying the BNE price to capacity constructed within a particular year as has also been suggested would create a highly complex mechanism and which could be considered as discriminatory, especially in regard to older plant for which such prices would have to be nominated. The Regulatory Authorities do not consider such discrimination or complexity to be either reasonable or justified and therefore intend to retain the year on year BNE pricing mechanism as proposed.

Table 1 below shows the breakdown of costs to determine the total investment cost of €81.015 million. Employing the WACC of 7.83% and the 15 year lifetime, this cost can be converted to an annualised Investment Cost of the BNE peaking plant. The resulting annualised cost is €9.367 million.

Table 1 Investment Cost Estimate for 'Best New Entrant' Peaking Plant (€ '000s)

Site procurement	**2,500**
Pre financial close costs	
Project developer's cost	1,000
EIA	150
Engineering	100
Financial and legal costs	250
Total	**1,500**
Post financial close costs	
E.P.C. Contract	
EPC (including contingency)	66,744
Electrical interconnection	2,500
EPC Total	**69,244**
Other Costs	
Owner engineering, project management	1,039
Spares	2,424
O&M mobilization	350
Cost of IDC	2,574
Contingencies	1,384
Other Costs Total	**7,771**
TOTAL INVESTMENT COST	**81,015**

VIII. ANNUAL NON-FUEL OPERATION COST

(a) Operation and Maintenance

This heading considers matters typically addressed through a Long term Service Agreement and also includes owner's salaries. The estimated cost of these items is €0.564 million per annum.

(b) Insurance

Insurance costs are estimated to be €1.836 million per annum and reflect the stabilisation in the risk profile of power plants as observed by global insurance markets and insurance costs prevailing for similar power plants.

(c) Rates

The estimated cost of Rates is €1.854 million per year.

(d) Owner's general and administration costs

Owner's general and administration costs include all administration costs as well as costs associated with the required Generation License and Market Operator charges. These are estimated to be €0.776 million per year.

(e) Transmission charges

Generation users pay locational Use of System charges depending on the relative costs imposed on the system. For a BNE plant that is located in the south-west and connected to the transmission system at 220kV, indicative annual transmission charges are approximately €0.970 million.

(f) Fuel Storage

An allowance of €0.110 million has been made to reflect the working capital costs of storing fuel on site.

Based on the above the estimated annual non-fuel operational costs are estimated to be €6.110 million.

IX. INFRA MARGINAL RENT DERIVATION

(a) Preferred Methodology for Deriving Energy Market Inframarginal Rents

A number of parties provided comments on this element. Of those who expressed a preference regarding the three methodologies (1, 2(a) and 2(b)) one considered Methodology 1 to be too simplistic and possibly impractical given the potential for the solution not to converge, while Methodology 2(a) could give unreliable results. Consequently this respondent preferred Methodology 2(b) though it considered it to be important that Plexos be configured to use half-hour periods rather than hourly in order not to overstate running requirements. Another respondent recognised the limitations of Methodology 1 but considered the approach in Methodology 2(b) to be unrealistic since it used the unit commitment from one schedule and prices from another. Overall this respondent preferred methodology 1, perhaps enhanced to limit the number of starts.

It has been suggested that infra-marginal rents should not be deducted from the BNE price at all, as it conflicts with the underlying economic theory of the BNE unit being marginal in an equilibrium setting. The Regulatory Authorities have on previous occasions stated that the deduction is necessary in order not to over-remunerate plant. These rents accrue due to the currently sub-equilibrium settings of the plant mix on the island and therefore the Regulatory Authorities consider that it is correct that they be accounted for.

The Regulatory Authorities concur with the view that Methodology 2 is more likely to provide a better estimation of the operational schedule for the peaker than Methodology 1. The key drawback of Methodology 1 is the manual assessment of the running schedule based on shadow prices which, as commented by one respondent, may not provide a converged solution. Furthermore of the remaining two options Methodology 2(b) is preferred over 2(a) by the Regulatory Authorities as it utilises a representative dataset rather than a pseudo dataset for a mini peaker. The Regulatory Authorities note the comment regarding the use of different Plexos runs for deriving firstly the unit commitment schedule and then calculating the infra marginal rents however, in the underlying theory of the CPM it is assumed that the market is in equilibrium and therefore the RAs are interested in establishing the inframarginal rent resulting from the current competitive system state and not an artificial scenario whereby the SMPs have been dampened as a result of an additional generator.

The Regulatory Authorities have decided to utilise Methodology 2(b) for the calculation of Energy market infra marginal rents. This option completes two Plexos runs, one with the BNE peaking plant and all its characteristics and one without. A unit commitment schedule will 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 SMP estimations from the second Plexos run (without the BNE peaking plant included).

Regarding the configuration of Plexos the Regulatory Authorities preferred approach is to match the timings in the Trading and Settlement Code and therefore the runs would be based on half-hour periods, however the validation exercise undertaken for the Regulatory Authorities by KEMA was against a version of Plexos with hourly periods as a technical limitation within Plexos prevented half-hourly periods being employed. The Regulatory Authorities wish to conduct any modelling against a validated version of Plexos and therefore hourly periods have been used in determining the inframarginal rent, however if the limitation which has had to be applied has had a material impact it is more likely that the inframarginal rents may have been understated rather than overstated.

Comments were also received regarding the derivation of the SRMC for the BNE peaker. One respondent noted that the second Plexos workshop identified a number of costs which had not previously been considered in the context of SRMC. The Regulatory Authorities note that the choice of fuel type for the BNE peaking plant means that a number of the costs identified by the respondent are not relevant (since they refer to gas costs). Furthermore the approach utilised by the Regulatory Authorities in estimating the inframarginal rents for the BNE peaker for 2007 was to utilise the Plexos model and dataset produced through the Plexos validation workstream undertaken by KEMA, applying the relevant technical and cost characteristics to the BNE peaking plant except for the variable O&M cost which in the first instance was set to zero to establish whether the BNE peaker would be in merit purely on consumable costs. The modelling results estimated that the BNE peaker would be in merit but for only a limited period of time. The Regulatory Authorities subsequently reviewed the variable O&M data and together with advice from expert consultants derived a view of a reasonable variable O&M cost based on the underlying assumptions contained within the variable O&M costs for the other plant in the dataset. The modelling was then re-run and resulted in an estimated inframarginal rent for the BNE peaker for 2007 of €2,582,510, equating to €14.19/kW.

(b) Ancillary Service Revenue Derivation

Two respondents argued that the use of ROI ancillary service rates would disadvantage NI generation since they receive lower ancillary service payments than is assumed in the derivation of the CPM prices. The Regulatory Authorities consider that the use of Ancillary Service revenues based upon RoI rates is a consequence of the unit being sited in RoI (the reasons for which have been addressed earlier). To apply NI rates would not be representative of the income a BNE peaker located in RoI might be expected to earn and would result in the fixed cost estimate being over-stated. The existing differentials between RoI and NI Ancillary Service arrangements are recognised by the Regulatory Authorities and work is ongoing to review the Ancillary Service arrangements under the SEM with a view to harmonising them in the future.

The Regulatory Authorities remain of the view that estimating the Ancillary Service income for the BNE peaker based on RoI rates and the results of the Plexos modelling work undertaken for the inframarginal rent determination for 2007 is the most appropriate approach given the proposed location of the BNE peaker. Given this, the different types of reserve and the applicable 2007 rates are set out below. It should be noted that the estimates produced have been based on EirGrid's existing Ancillary Service arrangements.

The different Reserve types and their corresponding 2007 rates are defined as follows:

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

The Reactive Power rates are as follows:

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

The Plexos generation results for the BNE in 2007 yielded an estimated Ancillary Service revenue for 2007 for the BNE peaking plant of €1,114,101, which equates to €6.12/kW/yr to be deducted from the estimated annualised investment cost and the estimated annual non-fuel operational cost of the BNE peaking plant.

X. FINAL BNE PRICE

The Regulatory Authorities have decided that, based on an analysis of the latest data, the BNE peaking plant price for 2007 is €64.73/kW/yr. The costs are summarised in Table 2 below.

The following are the key points in relation to the calculation of the BNE for 2007:

Table 2: BNE Component Summary

Costs		***BNE 2007***
Annualised capital cost		
Capex	€ '000	81,015
Plant life	years	15
WACC	% p.a.	7.83%
Annualised cost	**€ '000**	**9,367**
Fixed costs		
LTSA	€ '000	564
Transmission charges	€ '000	970
Owner's general and admin costs	€ '000	776
Insurance cost	€ '000	1,836
Rates cost	€ '000	1,854
Fuel Storage	€ '000	110
Total	**€ '000**	**6,110**
Capital plus fixed costs	**€ '000**	**15,477**

	€/kW/yr
Unadjusted BNE Cost	85.04
Energy Market Infra Marginal Rent	(14.19)
Ancillary Service Revenue	(6.12)
Final BNE Cost	**64.73**

APPENDIX 1 – RESPONSE TO COMMENTS

Comments Received on the Fixed Cost of a New Entrant Peaking Plant Decision and Further Consultation paper 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 CPM, Decision and Further Consultation**
Document Ref Number:	AIP/SEM/07/14
Comments to be returned by:	13/03/2007
Comments returned to:	Peter Halligan (peter.halligan@ofreg.gov.ni)
Document Author:	Peter Halligan

Respondee	Heading / Comments	Response
	Technology Choice / Capex	
Viridian	A future change in technology could strand the investment in a mid-merit or peaking unit that is made today. This risk needs to be priced by a prospective investor. This risk could also include the risk of the regulatory authorities changing their technical assumptions, for example assumptions on fuel type or fuel transportation (eg. whether gas capacity is a fixed or variable cost)	It is possible that the BNE technology could change over time, though any new machine would need to have sufficient operating history to meet the “proven technology” criteria, but this is a reflection of reality. Similarly the fuel choice could change for the BNE as world prices or infrastructure costs change but this again would reflect reality. The Regulatory Authorities are not seeking to eliminate the underlying market risk that is already present in the energy only market which the CPM seeks to replicate.

Viridian	The global market for power plants has a significant cyclical nature. The recent increase in EPC prices is an example of this – the prices quoted in the consultation are already 20-30% less than the current market prices as recently quoted to VPE from manufacturers.	The Regulatory Authorities are conscious that from the time the annualised CPM pot has been set until its review the following year, EPC costs may vary up or down, However the Regulatory Authorities believe that an annual recalibration of costs strikes the right balance in estimating the price of peaking capacity.
NIE	The derivation of the BNE costs in Section VI of the paper makes no reference to the capital cost of constructing fuel storage and handling facilities. There is also no reference to the capital cost of actually holding backup fuel stocks. These costs should be included.	The cost of constructing fuel storage and handling facilities is included in the EPC cost (NB the capital cost used in the February Consultation Paper was for a dual-fuel plant). Re: fuel stocks, if it is assumed that the BNE held a notional 3500 tonnes of distillate in stock at a price of €400/tonne (see "Fuel Price and Generator Maintenance Assumptions for use in SEM Modelling", December 2005) the purchase cost would be c.€1.4m. However, the cost to the project is the additional cost of working capital tied up in fuel, about €110k per annum using a WACC of 7.83%. This has now been included in the recurring cost determination for the BNE peaker.

	Fuel Choice / Gas Capacity Charges	
ESBPG	There is limited liquidity in the secondary market in gas capacity in Ireland and PG believes that there is very little if any liquidity in Northern Ireland. A new entrant peaker could not rely on the secondary market in gas capacity as capacity may not be available on the day. This leaves the proposed short term products proposed by BGE. If a peaker is scheduled to run in the indicative actual schedule (IAS) they would be able to purchase such day-ahead capacity. However, if they were not scheduled in the IAS they would not purchase capacity and if they were required to run on the day they would be relying on the illiquid secondary market. As there is no guarantee that capacity would be available in this market the peaker may have to burn distillate and therefore would have to factor into its bids the probability and impact of this.	After review of the comments received from respondents on both the liquidity of the secondary market and the stage of development of short term gas capacity products, the Regulatory Authorities have concluded that the BNE peaking plant should run on distillate only since this has a lower overall cost than a gas-fired plant and, therefore, an investor would select a distillate only plant over a gas-fired plant.
ESBIE	It is the view of ESBIe that the costs of booking gas capacity should be included in the fixed costs of the plant, albeit that this capacity may be interruptible.	See above.

Airtricty	The BGÉ principles state that transportation revenue will not be adversely affected by new short-term services. Based on the bilateral market above, demand from BGÉ short-term services may well be concentrated in winter. This suggests a need for premium pricing, compared with annual pro-rata daily charges, if gross income is not to be affected. Furthermore, booking priority is given to annual and then monthly services. As daily services can only be booked up to 8 days in advance, there is therefore no guarantee that any daily peak capacity service will actually be available from BGE in winter. The proposed day ahead interruptible service is therefore unlikely to be useful to peaking generators as they cannot offer dual fuel bid prices, to allow for within-day interruption.	See above.
Synergen	The key issue is not the general development within the Irish gas capacity market rather the likely market liquidity and daily gas capacity prices at times of system stress. It is not clear to Synergen that a BNE Peaking Plant would be able to buy gas capacity at times of electricity system peak as we understand that this daily gas capacity will be non-firm. Furthermore, it is not prudent to assume that all unwanted portions of an annual gas capacity can be sold at anything other than a "fire sale" price. Therefore, Synergen considers it prudent to assume (until the gas capacity market has matured) that: (1) there is no liquidity in the secondary gas capacity and (2) the off peak value of gas capacity is low. Accordingly, the full costs of annual gas capacity should be included within the BNE Peaking Plant cost basis.	See above.

Viridian	The decision argues that these costs can be considered as variable and thus excluded from the capacity payment mechanism whereas the SMP modelling review by KEMA assumes that the costs are fixed and thus excluded from the SMP. Gas transportation costs must be recovered somewhere in the market if power plant owners are to receive a reasonable return on their investments.	See above and note that the KEMA view expressed at the Workshops was also on the basis of an understanding of a lack of liquidity in secondary trading.
NIE	if a peaking plant is to be "available" each day and declares itself available, it must have the gas capacity available to support that declaration: otherwise it is making a fraudulent declaration (probably in breach of the Grid Code). Hence on a daily day ahead basis (and for the duration of the trading day) it needs to have the gas capacity regardless of whether it is actually called upon by the System Operator to run. Hence gas transportation capacity is a sunk/fixed cost. Moreover, the SRMC bids do not recognise gas capacity costs as a legitimate marginal cost and hence the RAs proposals effectively exclude the recovery of fixed gas transportation costs in the market.	See above and note the remark regarding the KEMA validation work above.
ESRI	The issue of the cost of a gas connection and gas capacity is discussed. As a peaking plant will, by definition, produce very little electricity, higher fuel costs could easily be dominated by higher fixed costs. This suggests that a peaking plant should run on gas diesel rather than gas, if connection and storage for gas are not already present at the site of the peaking plant.	See above.

	Infra marginal Rent	
Airtricity	The paper proposes two methods for calculating energy rents: • One based on a hypothetical unit commitment based on "as is" SMP/SPh forecasts and one based on inclusion of a new peaking unit in a Plexos run. We are concerned that the hypothetical schedule could potentially be infeasible/impractical due to a high number of start/stops, though periods when SRMC is greater than SPh are excluded. However, we note that periods when FULL costs are greater than SMP are also excluded, which will not necessarily occur in real outturn MSQs. Such periods will reduce energy rents. • The second option is a Plexos analysis, using either a 1MW proxy or full sized (180MW) unit. With the full sized unit analysis unit commitment is derived from adding the unit to the existing plant database, but the prices derived are based on another run that assumes that the new plant does not exist. The logic of this approach is not immediately apparent, as this scenario could never exist in practice (i.e. the unit exists but does not affect prices). If the alternative Plexos option is chosen, logic would suggest that a run using both the unit commitment *and prices* resulting from addition of a notional 180 MW unit is the only internally consistent option.	The Regulatory Authorities have ruled out option 1 for the reason that the commitment schedule derived is over simplistic and does not take into account Start Up and No Load costs of the BNE peaking plant. Option 2a has been ruled out given the nature of the Plexos software and the sensitivity surrounding the commitment of such a small unit. The CPM theory is predicated on the underlying assumption that the market is in equilibrium, having established this principle the Regulatory Authorities are interested in establishing the infra marginal rent resulting from the current competitive system state and not an artificial scenario whereby the SMPs have been dampened by the inclusion of the BNE peaking plant. This is why Option 2b proposes using two Plexos runs, the first to establish a running schedule for the BNE plant and the second to identify the possible rents which such a plant would earn against that running schedule but using prices forecast to outturn based on the actual plant mix.

Synergen	In order to produce a reasonable estimate of infra marginal rent for the BNE Peaking Plant it is important to ensure that the key assumptions are robust. A key element is the SRNC bidding assumptions for all plant. The slides from a second workshop on the PLEXOS model have recently been published as AIP/SEM/07/43 and this document highlights a number of potential components of SRMC that had not previously been assumed within the modeling. These were set out as: • loss of capacity payments from a constrained plant; • cost of credit lines and broker fees; • gas Transport Charges; • higher SRMC for testing days of back up fuel; and • costs of switching from main to back up fuel to increase maximum capacity.	The Regulatory Authorities note that the choice of fuel type for the BNE peaking plant means that a number of the costs identified are not relevant (since they refer to gas costs). Furthermore the approach utilised by the Regulatory Authorities in estimating the inframarginal rents for the BNE peaker was to utilise the Plexos model and dataset produced through the Plexos validation workstream undertaken by KEMA, applying the relevant technical and cost characteristics to the BNE peaking plant except for the variable O&M cost which in the first instance was set to zero to establish whether the BNE peaker would be in merit purely on consumable costs. The modeling results estimated that the BNE peaker would be in merit in some periods. Subsequently the Regulatory Authorities reviewed the variable O&M data together with advice from expert consultants, in order to derive a view of a reasonable variable O&M cost based on the underlying assumptions contained within the variable O&M costs for the other plant in the dataset.
Viridian	The insistence of the regulatory authorities to value this as part of a BNE OCGT annual price setting introduces new variables to an investment decision over which a generator investor has no control, eg: other generator availabilities, projected fuel and carbon prices, system demand.	The Regulatory Authorities have previously stated that failure to take account of the infra marginal rents a peaking plant might expect to earn in the market will lead to overcompensation in the market. The Regulatory Authorities note however that it would be assumed that the matters identified would be considered by any potential investor in determining whether or not to construct new capacity or re-furbish existing capacity and their inclusion in the BNE costing is therefore consistent.

NIE	If there is technical progress this should be allowed for in assessing the cost of capital and so raise the cost estimate in other ways but, in their response to NIE's comments (p44), the RAs say, "there is little evidence to suggest that the cost of peaking plants will decrease over time or that efficiencies will dramatically increase." If so, this source of energy credits is excluded. If there are smaller less efficient peaking plant in place this suggests that the increment being considered by the RAs is too large, significant disadvantages of size are being ignored and the capital costs are understated (rather than that it is legitimate to deduct an energy credit). NIE has argued this in previous responses and remains of this view. It may be possible to argue that it was efficient to install smaller, more expensive plant when the systems were separated and before the SEM but that the larger scale is now appropriate. However, the argument is not very persuasive and, even if valid, implies only a transitional impact.	The Regulatory Authorities have stated that Infra marginal rents may be earned by a BNE peaking plant and this has been investigated using the validated Plexos results. As previously stated the Regulatory Authorities are of a view that failing to account for these rents will lead to over compensation in the market. The Regulatory Authorities have consulted with both the TSOs and independent technical consultants as to the Best New Entrant peaking plant and are confident that the notional peaking plant selected represents a suitable choice on which to derive the value of peaking capacity on the Island.	

ESRI	The logic behind the capacity payments scheme is that capacity payments should make it profitable to invest in a peaking plant if capacity is below the desired level and unprofitable if it is above that threshold.[3] In principle, where capacity is 1MW below target, that 1MW of investment should be incentivised by the capacity payment regime. However, as it might be the last MW of capacity in the dispatch order it might not run at all in the year. Thus for it to be built, it should be able to get all its costs back from the capacity payment. (The exception to that is the payment for reserve and ancillary services.) Thus the proposal to deduct an estimate of potential profits over and above energy costs (from actually producing electricity) from the capacity payments seems inappropriate, as it reduces, perhaps even eliminates the incentive to build peaking plants.	The capacity payment seeks to capture the amount of money over and above SRMC based pricing needed by the industry to allow a BNE peaking plant to cover its fixed costs whilst also making a normal rate of return through the inclusion of an appropriate Weighted Average Cost of Capital (WACC). The CPM does not take account of a potential shortfall or oversupply of installed capacity, for the purposes of setting the annualised fixed pot it is assumed that the market is in equilibrium and that the notional peaking plant has already entered the market. If, as suggested by the comment, the modelling had indicated that the BNE peaker will not operate, no deduction for energy revenue would be made. However the modelling suggests that the peaker would operate, the Regulatory Authorities thus consider it appropriate to deduct an estimate of the profit such a peaker would make in the energy market in order to avoid any element of double payment (the energy market profit would contribute to the fixed costs already being covered by the CPM leading to a double payment).

[3] Obviously they also have a vital incentive effect driving new investment across the spectrum, including base load.

	Other Issues		
ESBPG	The RAs examined a single new entrant peaker entering the market rather than an economic efficient number entering to displace more expensive units. PG believes that it would be more correct to assume that entry is efficient and therefore more than one unit would enter.	It is possible that there may be a number of new entrants into the market once it is implemented and furthermore such new entrants may not all be peaking plant. However in determining the size of the CPM "pot" the Regulatory Authorities have selected a method which seeks to emulate the pricing in an unconstrained energy only market so as to identify the 'missing money' which Generators would otherwise receive in the absence of a CPM. This money is identified at the peak where prices are set by peaking plant and such prices would be paid to the entire volume of scheduled plant. The volume is determined in the CPM as that capacity required to meet the security standard and the price is set by a BNE peaking plant. There are of course other methodologies which could have been employed but this was the Regulatory Authorities preferred approach. Hence pricing is by reference to a single BNE peaker and not an estimate of other possible market entry scenarios.	
ESBIE	ESBIe consider that the power output degradation of 4% would be more appropriate than the 3% level quoted, based on ESBI industry experience.	After independent technical advice, the Regulatory Authorities consider a 3% degradation to be appropriate in this instance.	

Airtricity	The paper suggests that a peaking plant will have an availability of 95% (13 days planned, 2% FOR). However, each start of a plant incurs the equivalent of a certain number of operating hours, e.g. 8-16 hours for each start. If peak plants are started frequently, eg twice per day, then this assumption of availability may be unduly optimistic. We believe that additional Plexos modeling is essential before an informed decision can be reached on the value of this fundamental parameter.	The Regulatory Authorities have received independent technical advice on this parameter and are satisfied that the number quoted is appropriate.

Synergen	The BNE Peaking Plant's overall revenue is likely to comprise a higher proportion of CPM payments than a baseload plant – which would expect to see a majority of its revenue come from energy payments. The CPM regime (as currently envisaged) is subject to regulatory discretion in a number of areas when setting the level, and potentially the allocation of CPM revenues. As uncertainty increases the risk profile of a generator, the BNE Peaking Plant can reasonably be expected to have a higher risk profile compared with a BNE Base Loader. Thus Synergen does not accept RAs assertion that the risk profile for a BNE Peaking Plant is the same as for a BNE base load plant. Thus, the RAs should allow the BNE a higher WACC than the 7.83% suggested in AIP/SEM/07/14. The RAs' hourly modelling is of concern. It is plausible that PLEXOS will schedule a plant for a one hour period but with exactly the same data the ABB market software would only schedule the unit for 30mins - therefore halving the related infra marginal income. This matter is potentially material, in the extreme the estimated infra marginal rent could be double that like to arise once the SEM is live. It is unclear whether the RAs present modelling approach is expected to be based on half-hourly modelling (but previous modelling has not been). Synergen believes that any modelling that is utilised to underpin commercial decisions should be clearly based on a model that is validated as being wholly aligned to the T&SC.	The Regulatory Authorities 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 Regulatory Authorities 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 base load plant in the SEM and under the suggested scenario its income would be more certain since its exposure to the energy price would be less than for a baseload plant. The Regulatory Authorities are committed to aligning the Plexos modelling as much as possible and have recently completed a validation process which included industry participants. In determining the BNE inframarginal rent, the Regulatory Authorities have employed this validated model and associated dataset. The validated model uses an hourly period due to a technical limitation in Plexos however the Regulatory Authorities consider that this is acceptable and further it would, if anything, understate the possible inframarginal rent rather than overstate it.

Viridian	This annual target is set on a security standard which could change and even if it remains constant the generation requirement will be based on assumptions of forecast demand, forced outage rate assumptions and scheduled outages. Generator capacity in excess of the standard requirement will reduce the capacity payment below the BNE OCGT value In the VPE response to the T&SC, v1.2, we set out our concerns that the complicated formula for capacity pot distribution result in a baseload plant mathematically always receiving a higher payment than an equivalent peaking plant (with the same capacity and availability). VPE suggest that the solution to this is not to increase the BNE OCGT price but to alter the distribution formula in the T&SC. The former approach would increase the cost to customers and still result in a bias in favour of baseload over peaking plant. There at least two areas where the RAs have presumed that the BNE OCGT must be sited in Ireland rather than Northern Ireland, namely: a. The WACC is based on a corporation tax of 12.5% rather than the 30% that would apply to a plant that was sited in Northern Ireland, or to any company that was based outside Ireland but investing in Ireland. b. The ancillary service income in Northern Ireland could be as much as [40%] lower by comparison to Ireland. This lower ancillary service income would result in a higher capacity price.	In the event of over capacity (as suggested in the comment) it is true that the per unit payment under the CPM would fall relative to a situation where capacity was just sufficient, however this is a correct signal since it provides an incentive for the 'correct' level of capacity. As noted in the recently published responses to the comments on T&SC v1.2, the Regulatory Authorities are currently reviewing the comments provided regarding this matter as part of their work in establishing the values of VOLL and PCAP to which the comment relates. In considering where a BNE peaker would site the Regulatory Authorities considered a number of factors including current system dynamics, subsequent locational signals and corporation tax. In addition any investor would also consider the applicable Tax regime and therefore the Regulatory Authorities have considered this too. Having considered all of these factors the Regulatory Authorities are of the view that a BNE peaker would site in RoI. With regards to Ancillary Service revenue, the Regulatory Authorities are committed to harmonising the arrangements North and South and are taking this forward.

Viridian	VPE note that the decision/consultation document uses the above figure [the BNE Price] on an installed basis, but this must be calculated on an available basis. No power plant is available 100% on a sustained basis and thus the income per available MW must be higher. The RAs recognised this in their original consultation but this factor has been lost in the most recent decision/consultation VPE do not disagree with the availability assumptions in the paper, but note that they must be applied to the income stream.	The matter of availability is considered in the establishment of the Capacity Requirement. To do so here as well would double count the impact.
NIE	In section 3(a), "Revenue Assumptions", the proposal is to use RoI ancillary service rates. This will disadvantage NI generation since they are receiving lower ancillary service payments than is assumed in the derivation of the CPM prices. Similarly, the use of the lower RoI corporate tax rate means that, even if the other items in the WACC calculation were correct, the cost would be based on a cost of capital lower than is available in Northern Ireland.	See above.

ESRI	The decision to opt entirely for *Methodology 2* over *Methodology 3* is questionable. If the SEM market were to survive indefinitely as currently outlined, investors in peaking capacity would face a very different risk on their investment than would investors in base load plant. If any modelling is done of the expected life cycle costs and benefits for an investor, it should separate out the sources of revenue and take account of differential risk. Both types of plant face the possibility of serious plant failure outside of their guarantees from the manufacturer. A new base load generator faces considerable uncertainty about future fuel and carbon prices as well as about the rate at which new firms enter the market and how technical progress will affect their efficiency. It also faces regulatory uncertainty about how long the promised capacity payments regime will persist. A peaking plant only faces the regulatory uncertainty. These arguments suggest that the cost of capital for a new peaking plant should be much below that for a base load plant. While because of regulatory risk and risk of plant failure it may not be as low as would be suggested for a totally safe investment, the cost of capital assumed in *Methodology 2* must be too high. If regulatory uncertainty is important for new entrants, consideration should be given to how such risks could be reduced or hedged in the interests of both investors and consumers. The decision to run with *Methodology 2* rather than *Methodology 3* has met with the approval of most if not all those who have commented. However, no comments have been received from the consumer interest.	The Regulatory Authorities opted against Methodology 3 as in order to attract commercial investment in all sectors of the generation stack, 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 3. The cost of capital outlined in methodology 3 relies on public ownership, and as previously stated the Regulatory Authorities value competition in the market, something which publicly owned peaking plant would fail to achieve. Whilst it is true that the costs identified are faced more by a baseload plant than a peaking plant they are costs which such plant would be likely to reflect into their SRMC and which, in turn, would influence the level of SMP in the energy market. Regarding the CPM itself, the Regulatory Authorities do not accept that there is a credible risk of the CPM being removed from the design of the SEM, however if such a risk did exist it would be faced by all parties equally and would not differentiate in the way suggested.

ESRI	The assumption that any new peaking plant will be an independent plant seems unduly restrictive. Because of the very different nature of a peaking plant to a base load plant, there may be substantial economies of scale arising from co-location with other plant. This has been the pattern in Ireland North and South in the past (and I suspect elsewhere) reflecting such economies of scale. Because the cost of ignoring such economies of scale would be reflected in capacity payments to all generators, it could substantially but unwarrantedly raise the costs for consumers. The costs from underproviding generating capacity may be greater than the cost of over providing. For this reason, given the uncertainties about the way the market may operate, it may be right to err on the side of generosity in incentivising new investment. However, provision will need to be made to gradually adjust the incentives to provide the correct long-term incentive. That implies that capacity payments will fall. How can this be done while maintaining the credibility of the new market?	There are two points to make here. 1.) Choosing an IPP as the basis for the capex determination does not preclude existing generators or use of existing generation sites. 2.) Allowing for an IPP to reflect the BNE proxy allows for the entry of new players, increasing competition in the market to the benefit of all customers. If the CPM were based on incumbent costs only such new entry could be compromised. The Regulatory Authorities are seeking to replicate the missing money of the SRMC based pricing market which assumes market equilibrium, and consider the best way to instill market confidence is to objectively set and maintain the current methodology & reduce perceived Regulatory risk.