Payments for Generation Capacity Margin

A Consultation Paper Issued by
the Director General for Electricity Supply
(Northern Ireland)

August 2002

Capacity Payments for Generation Security

1. Background

1.1 Prior to mid-1999, Northern Ireland Electricity's Power Procurement Business (PPB) as part of its licence duties was required to maintain a Generation Security Standard (GSS) for Northern Ireland. This standard required that NIE must have sufficient generation plant under contract to ensure that a minimum level of system black-outs and brown-outs (caused by generation shortfall) were experienced.

1.2 The European Directive on the Internal Market in Electricity (IME) required, amongst other things, that the electricity market for generation be opened partly to competition and the top tranche of consumers (35% by annual demand) have the right to opt for a wholesale energy provider other than NIE PPB. Until IME became law NIE PPB was in a monopoly / monopsony position in the Northern Ireland wholesale electricity market. Under the regulations put in place at privatisation in 1992, PPB was required to buy almost all generation output in NI via long term contracts and then derive a Bulk Supply Tariff which was made available to all suppliers, and from which all suppliers were required to source their energy.

1.3 In a system of this type it was appropriate that PPB should have the responsibility for the GSS, as its costs were met by all customers. Given that the continuing liberalisation of the electricity industry will mean that the PPB share of the total NI market will diminish, and with generation competition there will be no generation purchase obligation, the PPB cannot be tasked with maintaining any future capacity margin.

1.4 It is necessary to place the obligation for GSS with a body which will continue to operate in the market, and which is considered to be an impartial participant. The most obvious choice is the Transmission System Operator.

In NI the TSO function is presently carried out by System Operator Northern Ireland (SONI), which carries out the licence duties in relation to transmission system operation placed on NIE. NIE is the current owner of SONI. Ofreg is now considering responses to its recent consultation paper "An Independent Transmission System Operator for Northern Ireland" (March 2002) (http://ofreg.nics.gov.uk/) which sought views on the future ownership and structure of the TSO. It is accepted that the development of the market will require that the TSO be divested from NIE, and the decisions to be taken will relate to what form of ownership and duties the divested structure will have.

1.5 Views are sought on the appropriate body to manage the GSS.

1.6 The most important initial duty is that of producing a statement of future generation capacity. This was produced by NIE up to market opening in 1999. Its prior format was a yearly updated seven-year projection of generation capacity, demand, load growth and expected sources of new generation, retirements and differing projections of availability. This developed a matrix of likely outcomes over the following seven-year period.

1.7 Ofreg and SONI have agreed that this licence obligation should be re-instated as part of the TSO licence section, and will be passed on as a core duty of SONI when it is demerged from NIE.

1.8 Following the preparation of such a statement it is possible that an advanced warning of generation shortfall could act as a signal to the market to invest in new plant. However it is equally possible that no new generation proposal comes forward, and that a generation shortfall occurs.

1.9 One means to remedy this problem is to recover revenues from customers to contribute to a capacity margin payment, paid to all connected generators on the NI system who provide generation capacity.

1.10 The format of such a payment in the open market will need to guard against gaming by independent plant operators, and must be designed to prevent perverse outcomes. The detail of a capacity payment will be developed in conjunction with SONI, the Department of Enterprise Trade and Investment (DETI) and electricity licensees.

1.11 There are number of issues which need consideration, once the decision has been taken that a capacity margin or generation standard should apply. These are:

(i) what form should a standard take?

(ii) what value should be placed on capacity?

(iii) when should intervention take place if a standard is not likely to be met?

(iv) who should intervene?

(v) when, how and by whom should a standard be reviewed?

2. Format

2.1 In order to consider the most appropriate form of GSS, it is useful to establish some basic assumptions regarding the NI electricity sector.

2.2 The maximum demand on the system is approximately 1700 MW. The generation available to meet his demand is composed of both indigenous and interconnected capacity and the degree to which the interconnectors can be relied upon for capacity must be considered.

2.3 To summarise, from 2005 onwards there will be between 1739 and 1869 MW of indigenous connected capacity on the NI system, assuming a new 400MW power station is built at Coolkeeragh, including fast start gas turbines, and allowing for the differing capacity of Kilroot Power Station on coal and oil. It is reasonable to use the value of 1800 MW to approximate indigenous capacity. Using, for illustrative purposes only, prudent measures of interconnector reliability – 80 MW North-South, and 250 MW on Moyle (i.e.

allowing for single-pole failure), the total capacity available to the market could be calculated as 2130 MW.

2.4 The GSS in force prior to 1999 may be interpreted as being equivalent to a 20-25% capacity margin over peak demand. With peak demand of 1700 MW, the capacity margin at 25% would require there to be 2125 MW of generation capacity. The analysis above shows that, even including some interconnector capacity, the available generation capacity would be 2130 MW in 2005. Based on information available now regarding new generation build, there will be an absolute dependence on interconnectors to provide generation security in future. It is also worth noting that indigenous generation is estimated from 1739 to 1869 MWs – a figure marginally above the NI system peak.

2.5 A capacity margin of 25 % over system peak would require a further 425 MW of system capacity – i.e. 2125 MW.

2.6 Views are sought from respondents on:(i) the basis on which a capacity margin should be set, and particularly the size of margin, (ii) the basis on which interconnectors can or should be included, (iii) the value of generation capacity and (iv) the timing of its introduction.

2.7 The existing market structures in NI already place a value on capacity, through the Bulk Supply Tariff produced by NIE PPB. The value is set at £36 per kW. The value of capacity for the purposes of this consultation should not however be constrained to this valuation. Respondents are asked to comment on potential valuation methods, with particular reference to the relative position of generation capacity payments in the Republic of Ireland. The valuation of capacity should be considered to be revisable over time as circumstances in the market change.

3. Allocation of Capacity Payments

3.1 There are varying means of rewarding capacity, but the two options which are under consideration in this paper are a capacity based approach and an energy based approach.

4. Capacity Based Approach

4.1 Under this approach a daily assessment is made of spare capacity on the system, at the time when the capacity margin is at its minimum. Assuming that an individual generator's capacity does not reduce below this level during the day, then a daily system level of available but unused MW of capacity is calculated. It is then possible to allocate the capacity margin fund across those generators which have available unused capacity. It would be based on the capacity margin figure, and in a situation where the capacity margin for that day was greater than the standard, the payment would be scaled back accordingly.

4.2 To illustrate this method (and for illustration only), we can assume (based on the present BST capacity charge of £36 per kW with a margin of 425 MW) that a fund of £15.3 million is available per annum to meet the cost of generation capacity margin payments. Assuming further that this fund is allocated equally across the days in the year, then there is a daily allocation of £41,918 for capacity margin. With the assumed plant margin requirement of 425 MW, then the payment per MW per day is £98.63. If on a given day the system demand is 1500 MW, and there is a declared availability by generators of 1925 MW, then the system margin is being precisely met. If it is deemed that three generators are contributing to system margin such that generators A, B and C provide 100, 150, and 175 MW respectively then under these simple assumptions, A receives £9,863, B receives £14,795 and C receives £17,260.

4.3 If we use the same base assumptions as above, but the system demand is now 1300 MW and the available generation remains at 1925 MW, then the capacity margin is being exceeded by 200 MW. In this case the capacity payment would be adjusted downward such that the per MW allocation becomes (425/625 * £98.63) or £67. The daily allowed cost of capacity remains unchanged, but as it is now allocated across an additional 200 MW, the payment per MW is diluted.

4.4 Conversely, if the system capacity margin was narrower than the required margin then the payment per MW would increase. Long term situations where there was a capacity payment premium of this nature would act as a signal of a generation capacity shortfall.

5. Energy Based Approach

5.1 This method would allocate a capacity payment on the basis of undelivered energy or energy which could have been delivered. The approach could be based on the system peak and the indigenous generation capacity. Given that on average we can expect say 90% availability from generators, and that the NI system load factor is 64%, it is possible to calculate the potential energy production of local plant over the year, and the actual produced to meet the system demand. The difference in the two values would equate to the undelivered energy potential of local generators. A capacity value could be applied to each "undelivered" unit, and paid to generators depending on their output, load factor and availability.

5.2 This may be illustrated as follows: assume that there is 1800 MW of connected capacity on the system, with 90% availability. This could be expected to deliver 14,191 GWh over the year (i.e. 1800 MW*0.9 availability * 8700 hours per year). Further assume that a peak of 1700 MW will require delivered energy of 9,531 GWh (i.e. 1700 MW * 8760 hours * 0.64 system average load factor). This represents an undelivered potential of 4660 GWh per annum. Using the assumption above of £15.3 million capacity value, this equates to a flat rate of £3.28 per MWh.

6. Problems

6.1 The use of either a flat daily energy or capacity charge is open to criticism that it may be gamed by generators, and that it does not necessarily take into account the seasonal variation in the need for, and value of, capacity.

6.2 In the case of an energy payment, it is possible to value the daily unused energy potential according to a seasonal weight, which would be determined in advance and published. Short term changes to capacity, for example plant outages, could also be factored in to the weights, and capacity payments adjusted accordingly.

6.3 The capacity based payment could be further refined to allow the trading day of 48 half-hour settlement periods to each be used as a calculation base for available, used and spare capacity. Hence a close to real time approach could be developed to allocate GSS payments. It is worth noting that his approach is being followed in the Republic of Ireland.

6.4 Views are sought on the appropriateness of method chosen, and whether a capacity margin should be weighted seasonally or to adjust for time of day.

7. Other issues

7.1 It is important to note that the introduction of a capacity margin payment to generators will not grant new revenue to those generators which are under long term contract to NIE Power Procurement. The payments made to generators under the long term contracts will remain unchanged. It will however be necessary to calculate the capacity margin provided by contracted PPB plant in order to determine the allocation made to any other independent generation which qualifies for capacity payments. The payments made to generators by PPB should also separately account for the element of the contract cost which is deemed to be a generation capacity margin payment.

8. Consultation

Responses are sought on all the issues raised in this paper, and should be sent to

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Please include a one page summary with submissions. The closing date for submissions is Friday 6 September 2002.

Copies will be made available (on request) in large print, Braille, Audio Cassette and a variety of relevant minority languages.

Glossary of Terms

BST (Bulk Supply Tariff)	the tariff of that name published by NIE under Condition 3 of Part III of the Transmission Licence for sales of electricity by NIE acting through the Power Procurement Business (as defined in the Transmission Licence)
KW (kilowatt)	this is equal to 1000 watts
KWh	one "unit" of electricity
MW (megawatt)	this is equal to 1000 kilowatts or one million watts
GWh (gigawatt hour)	this is equal to the electrical energy produced, flowing or supplied by an electrical circuit during one hour (where 1 GWh is equal to 1000 MWh, 1 MWh is equal to 1000 kWh and 1 kWh is equal to 1000 watt-hours)
Load	the amount of electric power delivered or required at any specific point or points on a system
Load factor	is equal to the ratio between average usage and maximum demand
Peak demand	the maximum load during a specified period of time