Power NI Energy Limited
Power Procurement Business (PPB)

Possible Cancellation of Generating Unit Agreements in Northern Ireland

Consultation Paper

March 2014

Response by Power NI Energy (PPB)

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Power Procurement Business

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Executive Summary

Power NI Energy's Power Procurement Business (PPB) welcomes the opportunity to comment on the Utility Regulator's (UR's) consultation on the possible cancellation of Generating Unit Agreements (GUAs) in Northern Ireland.

PPB has sought to understand the basis of the UR analysis to identify why it is showing the GUAs to be a £35m cost for customers which contrasts with the UR's analysis from April 2012 that showed a benefit of £79m, despite there being no material change in the market fundamentals. PPB has identified a number of areas in the UR analysis where (i) material errors have resulted in over-stated costs and under-stated revenues, (ii) the analysis has failed to take account of certain revenues and avoided costs and (iii) the analysis has incorrectly assessed the limited downside risk and substantial upside benefit to customers.

Our review of the UR's analysis highlights a number of material errors and omissions even before considering the Plexos modelling (which for example, also under-estimates the value of the GUAs by ignoring the RoI generators' inclusion of the cost of short term gas capacity in their bids) which, when adjusted for, shows the value to customers to have been understated by a minimum of £166m which is summarised in the following table, and the application of which would change the economic assessment from a loss of £35m to a benefit of at least £131m. As the key economic consideration is the forecast effect on PSO charges, it is imperative that the economic analysis undertaken to support any decision on cancellation is rigorous, robust and defensible.

Cost/Revenue item	Increase in Customer benefit	
	Annual	**Over GUA term**
Use of Correct Gas transportation capacity charge	£1.5m	£13.5m
No reservation of firm gas capacity from October 2015	£12.4m	£99.6m
Use of Correct GTUoS charge	£0.1m	£0.7m
Inclusion of additional Ancillary Services (contracted since Nov 2013)	£0.7m	£6.3m
Unavoidable costs in PPB price control	£1.0m	£9.0m
Inclusion of CfD Risk Premium revenue	£2m - £3m	£18m - £27m
Other items (detail provided confidentially to the UR)	£2.1m	£18.9m
Aggregate increase in Customer Value	**£19.9m – £20.9m[1]**	**£166m - £175m**

[1] This represents the total annual increase from October 2015 and the aggregate for 2014/15 is £7.5m - £8.5m.

The GUAs are currently beneficial for customers as is evident from the fact that the PPB Amount was set to rebate c£3m to customers in 2013/14 tariff year while the actual position is that the GUAs have out-turned £6m ahead of forecast in the first 6 months of the year. PPB also forecasts the GUAs will remain extremely valuable for customers throughout the period to September 2023, with an aggregate value under the base case of £202m (in 2014 prices).

PPB is concerned that the Utility Regulator has published a “minded to” decision, based on incomplete and incorrect assumptions and information, which would result in a material detriment to Northern Ireland customers. At a time of significant concern over the prices of electricity in Northern Ireland the draft decision to instruct the early cancellation of the remaining GUAs, which will otherwise reduce costs for customers, would be particularly unwelcome and contrary to the UR’s objective to promote the interests of customers.

PPB has conducted comprehensive monthly modelling of the GUA value for the period to September 2023 and the results of this analysis show that the GUAs provide significant value for Northern Ireland customers totalling £202m (in 2014 prices) compared to the UR’s estimated cost of £35m.

	£ms (2014 price base)									
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
UR Base Case	-4.7	-2.9	-2.9	-2.9	-7.1	-5.7	-4.3	-2.9	-1.5	**-35**
PPB Base Case	18.6	21.7	21.8	20.7	24.3	27.6	29.5	24.9	13.3	**202**

There is also considerable strategic value in the GUAs as they provide substantial potential upside value with little downside risk. This provides a significant value skew for customers which is supported by the effective one-way hedge for customers who can harvest any such additional benefits with the comfort that the GUAs can be cancelled with 180 days notice should, in the unlikely scenario, the GUAs become uneconomic for customers. Examples of where additional value may arise include:

- the sensitivities with higher and lower gas, and higher demand show increased value;
- any additional revenues captured under the DS3 proposals to support increased renewable penetration;
- any re-balancing of revenues to ensure appropriate remuneration of mid-merit generators;
- any delay in the commissioning of renewable generators or earlier exit of conventional generators; and
- unplanned outages on plant ahead of the units in the merit order.

This upside bias in favour of customers is particularly valuable when there is significant market uncertainty arising from the requirement to reform the SEM and the retention of the GUAs provides insurance for customers through this period of change.

In relation to the wider policy considerations, of promoting effective competition; security of supply; diversity of supply and environmental sustainability, PPB believes there are negative implications from cancellation which the UR has not considered. While PPB considers that prices are the primary concern for customers these wider policy considerations provide further reasoning for not cancelling the remaining contracts.

The UR’s only potential wider policy benefit relates to simplification of the new I-SEM arrangements. However PPB does not agree that cancellation would materially simplify the new I-SEM arrangements and indeed the presence of the GUAs will ensure PPB’s knowledge and expertise will provide beneficial input into the design to ensure, for example, the role of intermediaries is appropriately provided for.

PPB considers there is a high risk that forward market liquidity could actually reduce as we understand PPB is the only participant that provides CfD volumes based on its higher level of constrained output.

As recognised in the consultation paper, it is very obvious that local market power would increase with cancellation of the GUAs and this would affect not just the energy market but also the contract and ancillary service markets. Avoidance of market power is clearly preferential to enhancing it and then seeking to implement measures to mitigate it, particularly as they may be more difficult to structure in the I-SEM.

PPB was surprised by the UR’s assessment of the value of the CCGT GUAs. The contracts were designed (when they were negotiated in 2000) to provide economic benefit to customers from April 2012 when availability payments reduced by 60%.

PPB had expected that the contracts would be maintained given both its own valuation and the value shown by the UR’s previous analysis, which was published less than two years ago (in April 2012). There is a very significant gap between the UR’s latest analysis and both the UR’s previous analysis and PPB’s latest analysis. Such a material change in the UR’s analysis demands an explanation and begs the question what has caused such a change. Further, given the design of the contracts to deliver significant value from April 2012, one would have expected the UR to examine in detail the underlying factors giving rise to such a paradigm shift, not least as a sense check on the analysis.

Modelling of the electricity market, and the value of the GUAs within it, is complex given the range of factors that influence it. A decision to cancel the GUAs is irreversible and hence an incorrect decision has major consequences for electricity costs for customers. Given the finality of a cancellation decision, it is imperative that the decision is based upon rigorous and robust economic analysis of all of the costs and benefits to Northern Ireland customers. This analysis must consider the full range of potential variations to assumptions, to ensure the information upon which any cancellation decision is made is properly founded and that the UR has met its legislative obligations.

PPB concludes that the GUAs, even at a low point in the revenue streams of mid-merit generators, will provide significant benefits for Northern Ireland customers with scope for significant further upside and with low downside risk, which is in any event mitigated by the ongoing right to cancel with 180 days notice.

Introduction

Power NI Energy's Power Procurement Business (PPB) welcomes the opportunity to comment on the Utility Regulator's (UR's) consultation on the possible cancellation of Generating Unit Agreements (GUAs) in Northern Ireland.

Section 1 of this response considers the results of the UR's analysis and in particular the assumptions and information used to underpin the UR analysis;

Section 2 provides specific comments on the consultation paper; and

Section 3 provides a summary of PPB's detailed analysis.

1. Comments on the UR Consultation paper and analysis therein

PPB was surprised by the UR's assessment of the value of the CCGT GUAs. The contracts were designed (when they were negotiated in 2000) to provide economic benefit to customers from April 2012 when availability payments reduced by 60%.

PPB had expected that the contracts would be maintained given both its own valuation and the value shown by the UR's previous analysis, which was published less than two years ago (in April 2012). There is a very significant gap between the UR's latest analysis and both the UR's previous analysis and PPB's latest analysis. Such a material change in the UR's analysis demands an explanation and begs the question what has caused such a change. Further, given the design of the contracts to deliver significant value from April 2012, one would have expected the UR to examine in detail the underlying factors giving rise to such a paradigm shift, not least as a sense check on the analysis.

PPB obtained the detailed analysis from the UR that supported the results published in the consultation paper and has examined the information to identify gaps in the analysis.

Gaps Identified in the UR's Economic Analysis

PPB has sought to understand the basis of the UR analysis to identify why it is showing the GUAs to be a cost for customers. PPB has identified a number or areas where (i) over-stated costs and under-stated revenues have been used, and (ii) the analysis has failed to take account of certain revenues and avoided costs.

The aggregate of these shows a very significant under-valuation of the benefit of the GUAs for Northern Ireland customers, and that is even before any consideration of the UR's detailed market modelling which we believe also understates the value of Inframarginal Rent that would be captured by the generating units, for example, because it does not reflect the value arising under the GUAs from the bidding in of gas capacity by non baseload gas fired generators in RoI.

The effect of correcting for the various cost and revenue items is summarised in the following table (with references to the sections of this response where the issues are addressed in greater detail).

Cost/Revenue item	Increase in Customer benefit		Reference in Detailed Comments
	Annual	Over GUA term	
Use of Correct Gas transportation capacity charge	£1.5m	£13.5m	*Section 2.1.2.1*
No reservation of firm gas capacity from October 2015	£12.4m	£99.6m	*Section 2.1.2.2*
Use of Correct GTUoS charge	£0.1m	£0.7m	*Section 2.1.2.3*
Inclusion of additional Ancillary Services (contracted since Nov 2013)	£0.7m	£6.3m	*Section 2.1.6*
Unavoidable costs in PPB price control	£1.0m	£9.0m	*Section 2.1.7*
Inclusion of CfD Risk Premium revenue	£2m - £3m	£18m - £27m	*Section 2.1.8.1*
Other items (detail provided confidentially to the UR	£2.1m	£18.9m	*Section 2.1.8.2*
Aggregate increase in Customer Value	£19.9m – £20.9m[2]	£166m - £175m	

Other areas where the value of the GUAs is under-stated

The analysis in the consultation paper also understates the value of the GUAs in other ways.

As we noted earlier, the UR model is not using the latest Commercial Offer Data bid structures that are being bid by generators in the SEM, including in relation to the bidding of short term gas capacity products (see Section 2.1.4). This means the Inframarginal rent earned by the units is underestimated which therefore results in the value of the GUAs being understated. It is not possible for PPB to quantify the level of under-statement as this could only be identified by re-running the UR's Plexos model. PPB's modelling approach captures this value inherently.

Similarly, PPB believes the methodology the UR uses to determine margins earned between what PPB is required to bid into the SEM in accordance with the Bidding Code of Practice and what it actually pays under the GUAs does not capture the full value and hence again under-values the benefit of the GUAs for customers (see Section 2.1.5). It is not possible, using the UR's methodology, to place a value on the magnitude of under-statement although again PPB's modelling inherently captures the value.

[2] This represents the total annual increase from October 2015 and the aggregate for 2014/15 is £7.5m - £8.5m.

In addition we expect the GUAs will deliver additional economic value for customers from the provision of ancillary services under the DS3 programme to support existing and increasing intermittent wind generation (see Section 2.1.6 for further details). The generating units were designed to be flexible and should therefore capture additional remuneration. Any such value would further increase the value of the GUAs for customers.

Policy Considerations

PPB believes the cost of electricity is the primary concern for customers and therefore customers' interests are likely to be best protected by minimising prices. We therefore consider that unless the GUAs represent a demonstrable cost for customers they should not be cancelled but should be retained to capture the value for customers. The surplus that is being realised this year provides evidence that the contracts are performing as they were designed and customers are capturing benefits.

In respect of the promotion of competition, PPB has been at the forefront of promoting competition in Northern Ireland since its creation in 1992 and there are many examples of PPB innovatively employing its expertise to promote competition in Northern Ireland for the benefit of customers (e.g. VIPP contracts, Renewable Output Factor to support renewable supply, Cross-Border sale of capacity to ESB, development of the SEM arrangements, and driving the SEM forward market and establishment of the Tullett Prebon trading platform).

To the extent that the continuation of the GUAs might be seen to be a complication in the design of the new market arrangements under the I-SEM, PPB does not agree that the absence of the GUAs could simplify the I-SEM, as intermediary arrangements such as those which enable the GUAs to be operated within the current SEM market, will continue to be required. PPB's experience and knowledge as an input to the new market design will provide a validity check to ensure such roles are properly accommodated in the I-SEM and as noted in the consultation paper, the continued existence of the GUAs would provide a level of insurance for customers in what will likely be a time of market and price uncertainty.

There is a significant risk that there would be a net reduction in overall liquidity and competitiveness in the forward markets. PPB is the only entity which has originated trading volumes based on constrained dispatch Any such reduction in contract liquidity could increase costs for customers as a result of increased exposure to market price volatility.

It is obvious that local market power would increase if the GUAs were cancelled and the avoidance of market power is clearly a much safer approach for customers than seeking to develop market power mitigation measures that are inevitably blunt instruments and which may be more difficult to structure in the I-SEM.

PPB's assessment of the value of the GUAs for Northern Ireland customers compared to the UR's analysis

PPB has conducted comprehensive modelling of the GUA value at monthly granularity for the period to September 2023. The results of this analysis (see Section 3) show that the GUAs provide significant value for Northern Ireland customers totalling £202m (in 2014 prices) compared to the UR's estimated cost of £35m and PPB's adjusted UR base case of £131m.

	£ms (2014 price base)									
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
UR Base Case	-4.7	-2.9	-2.9	-2.9	-7.1	-5.7	-4.3	-2.9	-1.5	**-35**
"PPB Ajusted" UR Base Case	2.8	16.9	16.9	16.9	12.7	14.1	15.5	16.9	18.3	**131**
PPB Base Case	18.6	21.7	21.8	20.7	24.3	27.6	29.5	24.9	13.3	**202**

PPB's assessment is much closer to the "PPB adjusted" UR analysis with the residual difference resulting from the fact that the UR modelling is not accurately reflecting the bidding behaviour of generators (particularly in relation to gas capacity) and the fact the UR rolls a number of costs / revenues forward whereas PPB's analysis more accurately models a number of the items.

2. Specific Comments on the UR Consultation paper

2.1. Economic Analysis - Methodology

Modelling of the electricity market, and the value of the GUAs within it, is complex given the range of factors that influence it. A decision to cancel the GUAs is irreversible and hence an incorrect decision has major consequences for electricity costs for customers. Given the finality of a cancellation decision, it is imperative that the decision is based upon rigorous and robust economic analysis of all of the costs and benefits to Northern Ireland customers. This analysis must consider the full range of potential variations to assumptions, to ensure the information upon which any cancellation decision is made is properly founded and that the UR has met its legislative obligations.

The analysis must also reflect that there is significant value in the optionality of the GUAs that allow for termination with a short notice period of 180 days.

The SEM is in the process of change but as yet there is no clarity over the future High Level Design of the market and the detailed design is unlikely to be known until later in 2015. The only possible means of forecasting is therefore to conduct the assessment based on the current SEM market, while acknowledging the fundamental economics of generation will have to be respected in the new market design to provide a reasonable return on investments. This should also include some re-balancing of revenues for mid-merit generators who are currently not receiving adequate remuneration, which will represent a risk to security of supply if it is not addressed. This under-remuneration is evident from the substantial increase in the PSO requirement in RoI in 2013/14 to support the Tynagh CCGT contract. Hence the valuation based on the current SEM market will undervalue the GUAs and any revenue re-balancing will increase the value for customers.

2.1.1. <u>Energy Payments (paragraphs 3.11 to 3.14)</u>

The UR analysis relies on the assumption that the energy cost bid in the Commercial Offer Data (COD) and the energy payments under the GUAs generally “cancel each other out”.

This is an incorrect assumption. The fuel costs that are used to formulate the COD must reflect the market price of fuel and not the contract price of the fuel that is purchased and PPB believes the UR analysis does not accurately reflect the GUA costs.

2.1.2. <u>Other GUA costs (paragraph 3.15)</u>

The consultation paper states that these cost items contribute only a small amount to the overall cost and have been based on rolling forward historic performance and historic values. However, there are a number of errors in the figures used in the UR analysis, including two in relation to gas transportation charges and one relating to generator TUoS charges.

2.1.2.1. Gas Transportation Capacity charges

The annual cost of the SNIP capacity charge used in the UR analysis totals £13.95m p.a. whereas the actual annual capacity charge is £12.66m which reflects the UR approved tariff for 2013/14 (Oct – Sept). The published tariff also provides estimated charges for subsequent years and the estimated charge for the 2014/15 gas year is £12.41m. Hence the UR analysis has overstated the gas transportation capacity costs by over £1.5m p.a. in 2014/15.

2.1.2.2. Gas Transportation capacity from October 2015

The UR analysis also assumes that PPB will continue to book 1m therms/day of firm SNIP gas capacity to reflect the maximum possible daily consumption of the CCGT units. However PPB has recently decided not to direct AES to exercise the Option with Centrica to continue to book firm SNIP gas capacity[3] and will instead rely on Short Term or Interruptible Gas Capacity from October 2015. PPB will not therefore incur a fixed annual capacity charge.

The increasing penetration of renewable generation in the market has resulted in lower load factors on all gas fired generating units, including CCGTs. Most gas fired units with low load factors no longer reserve long term firm gas capacity but rely on interruptible and short term gas capacity products. The Ballylumford CCGTs currently have a market load factor of 10%-20% and a constrained load factor of around 30%.

The UR analysis is therefore flawed as (i) the option has not been exercised to book long term firm gas capacity and (ii) it would not be economic to book annual, or under normal system conditions short term, gas capacity based on maximum possible daily consumption with the level of load factor which is forecast for the Ballylumford CCGT units. The non baseload gas generators in RoI (e.g. Poolbeg (which is the same technology as the Ballylumford CCGTs), Huntstown, Aghada, Marina, North Wall) and the Ballylumford Phase 2 units in NI do not book firm gas capacity.

PPB would therefore bid in the variable short term costs into the market in the same way as all the non baseload generators in RoI do and as the Ballylumford Phase 2 units have done since the commencement of the SEM. Therefore, even if the costs of short term or interruptible products in NI were to increase, these costs would be recovered from the market and PPB would not incur any fixed annual capacity charge. Based on the published gas transportation tariff outlook for the years 2015-2018, this further reduces the UR's estimate of PPB's costs by c£12m p.a.

It is also important to note that the reservation of firm gas capacity would be economically inefficient for Northern Ireland since it would be tying up capacity that is required by other gas shippers, for example to facilitate the development of the downstream market, including growth in customer connections in the Greater Belfast, Ten Towns and for customers supplied following the delivery of Gas to the West. This could also avoid Northern Ireland customers incurring the high charges proposed by CER for supply of gas to Northern Ireland through Gormanstown.

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[3] Discussed at a meeting with the UR on 5 March 2014 and followed up with a letter dated 28 March 2014

2.1.2.3. *Generator TUoS charges*

The GTUoS costs used in the UR analysis are also overstated by £80k p.a. The analysis assumes the annual cost to be £2.77m whereas the actual charge, based on the 2013/14 regulated tariff is £2.69m.

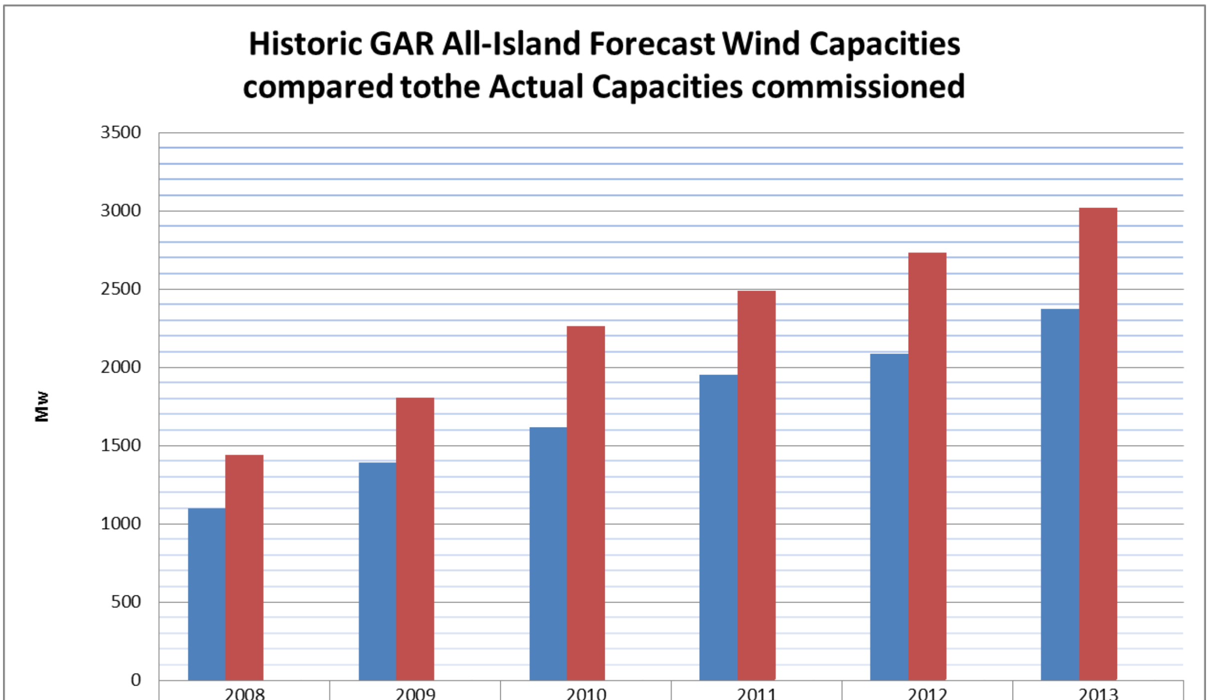
2.1.3. <u>Capacity Payments (paragraph 3.18)</u>

It is not clear from the information in the consultation paper, nor from the more detailed information provided by the UR, how new entrants and closures have been included. A further key issue is that renewable capacity has consistently commissioned more slowly than has been forecast in the GARs which have not been achieved in reality.

There is also considerable current debate on the future support for on-shore wind in the UK and a lot of adverse local reaction to planning applications for wind farms and the new transmission and distribution lines needed to facilitate increasing generation in RoI. This is also likely to delay investment and result in lower installed capacities that projected in the GAR.

The following graph shows that the trend has been for less than 80% achievement and therefore it would seem more reasonable to only assume 80% of the GAR wind capacities when estimating capacity payments to generators.

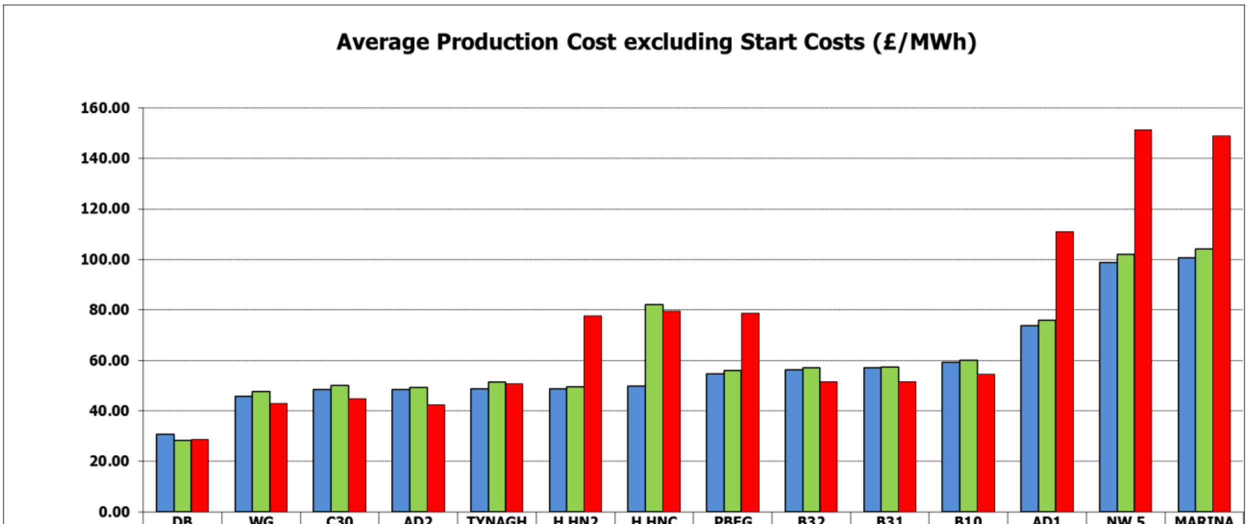
Our analysis has not applied any adjustment to the GAR wind capacities but if the capacity was reduced to 80%, our forecast CPM revenues would increase on average by approximately £0.75m per annum and there would also be further upside from increased dispatch.



	2008	2009	2010	2011	2012	2013
Actual	1099	1393	1616	1955	2088	2375
Av Forecast	1444	1808	2266	2493	2737	3021
Actual vs Av Forecast	76%	77%	71%	78%	76%	79%

2.1.4. Energy Payments (paragraphs 3.19 - 3.21)

We understand the modelling of Inframarginal rent does not reflect the inclusion of the costs of short term gas capacity costs in the Commercial Offer Data of non baseload gas fired generating units[4] in RoI who are including gas capacity costs in their bids, as can be seen from the chart below. This clearly has an impact on the merit order and scheduling of generating units and in the resulting SMPs and as a result the analysis in the consultation paper has significantly understated the IMR that will be captured by the Ballylumford CCGT units arising from increased scheduling and this will continue given the load factors on mid-merit plant will be increasingly variable with increasing wind penetration.



	DB	WG	C30	AD2	TYNAGH	H HN2	H HNC	PBEG	B32	B31	B10	AD1	NW 5	MARINA
February 2012	30.71	45.75	48.36	48.52	48.65	48.77	49.93	54.61	56.14	57.07	59.23	73.75	98.73	100.62
February 2013	28.24	47.53	49.95	49.33	51.52	49.65	82.03	56.12	57.17	57.20	60.10	76.02	101.99	104.16
February 2014	28.55	42.99	44.94	42.43	50.68	77.77	79.63	78.75	51.66	51.66	54.38	110.93	151.39	149.06

2.1.5. Constraint Payments (paragraph 3.22)

The level of constrained running is increasing and the actual output in 2013/14 was higher than the UR uses in its analysis (which is based on November 2012 to October 2013). This results in the VOM revenue estimates being under-stated when calculated using the UR's methodology.

The UR's methodology determines historic constrained running and then adds this each year to the Market Schedule Quantity (MSQ) that is determined from the UR's Plexos model. This aggregate provides the forecast Dispatch Quantity (DQ) from which the UR calculates future VOM revenues. However, where MSQ reduces with increasing priority despatch, the level of DQ may not fall as much and hence the level of constrained running may increase. By keeping the constrained output constant, the VOM revenues would be under-stated. PPB modelling of both the unconstrained and constrained dispatches automatically captures any variances that occur.

4 Aghada, Huntstown, Marina, North Wall, Poolbeg

Similarly, the trend shows that the CCGT generating units are starting more frequently and this is likely to continue as increased wind and the ensuing volatility will require greater utilisation of flexible generating units. The Ballylumford CCGTs have the cheapest CCGT startup costs in the SEM and hence are the units that have the most starts and stops. This trend will be picked up directly in PPB's analysis but if the UR continues to use it current methodology, it should also provide for increasing starts in line with the recent trend.

2.1.6. Ancillary Service Revenues (paragraph 3.23)

The consultation paper indicates that the UR analysis rolls forward historic revenues. However, we understand this does not take account of the additional services that PPB has contracted with SONI to provide (since November 2013). PPB estimates that this increases PPB revenues by c£0.7m p.a. PPB has also submitted proposals to SONI for additional services which, if accepted by SONI, will provide further value for customers.

PPB's modelling calculates the future HAS revenues from the forecast dispatch schedules that are output from its constrained modelling runs.

The power system of Ireland and Northern Ireland is in a period of considerable transition, particularly with respect to renewable energy and potentially the highest penetration of wind power plants on a synchronous system in Europe. Changes to: generation portfolio; system topology; and system operational characteristics, are presenting the system operator with significant challenges. In particular, the system operators have stated "the core operational functions of frequency control and voltage control will become more challenging" and " maintaining system security in the context of these issues will require the provision of enhanced system services, which will therefore become a key enabler of a more sustainable power system".

The Northern Ireland system has, relative to other power systems, always faced significant challenges in terms of frequency control. The loss of the single largest credible contingency has a potentially much greater impact on system security in Northern Ireland than in Europe; GB or indeed the Republic of Ireland. The Ballylumford CCGTs were therefore designed to provide the System Operator with the necessary flexibility to manage a small system such as Northern Ireland. These units were designed with low minimum generation levels, high ramp rates, are capable of providing high sustainable levels of reserve, and for the larger units, are able to start up quickly in (or switch to) open cycle mode.

The "Delivering a Secure and Sustainable Electricity System" (DS3) programme has identified a range of new System Service products, in addition to the existing products, required to address and mitigate the identified system issues. These new products include: Fast Frequency Response Product; Synchronous Inertial Response; Ramping Products (over 1, 3 and 8 hour windows); Fast Post Fault Active Power; and Dynamic Reactive Power.

The TSO has recognised in their DS3 System Service Review recommendation paper to the SEM Committee, that " a greater level of remuneration is required to incentivise the necessary performance level" and made specific recommendations on values. The TSO recommended that €355 million should be used to determine the system service product tariffs to be employed from 1 October 2015.

The TSO had completed their analysis for a number of remuneration approaches and also how different product configurations would impact on the level of remuneration accruing to different service providers. In Table 8 of the DS3 System Service Review recommendation paper to the SEM Committee the minimum, average and maximum revenues (€/ MW installed capacity) were detailed for each typical service provider for six different product configurations. The average revenue for CCGTs with the same installed capacity as Ballylumford under the six product configurations lies between €15.5m and €19.1m. The impact on the total capacity pot differs under each of the product configurations. The table in Appendix 2 summarises the potential increase in ancillary service revenue for the Ballylumford CCGTs based on the TSO analysis.

Whilst the Regulatory Authorities are undertaking their own independent economic analysis and which will input into a SEM Committee Consultation Paper due to be published in early May 2014, it is clear that the provision of ancillary services will be ever more critical and market payments for reserve, voltage support and inertia will have to increase (although there would be no change in GUA costs).

PPB has not included any potential increase in revenue in its modelling and therefore any increase in such revenues will increase the value of the GUAs to customers who will capture the full benefit of any increased revenues.

2.1.7. <u>Evaluating the value of the GUAs (paragraphs 3.24 – 3.26)</u>

The UR analysis assumes the current PPB price control allowance remains at its current level and that the full cost would be avoided if the GUAs were cancelled. This is incorrect as there are elements of the PPB price control that are not "avoidable". These include the PPB Regulatory Asset Base which has been depreciating since 1992 and which will be fully depreciated by 2017 at which point the PPB price control allowance will naturally reduce. Cancellation before the RAB is fully depreciated would require the residual RAB value to be recovered. Similarly, the price control provides for the recovery of pension deficit costs and again these will either at some stage be fully recovered or recovery of the full deficit cost would be crystallised at the point of cancellation.

If UR decided to cancel the GUAs there would be further business termination costs which could be significant. However, setting those aside, it is only the Incentivised Fee element of the PPB price control (the ICt allowance) that could be deemed in any way to be avoidable costs. In 2013/14, this equates to £6m rather than the £7m used by the UR, which improves the benefit for customers by £1m p.a.

PPB is willing to consider a different structure for its price control during the next price control period from April 2015 which may reduce the avoidable costs for customers particularly where benefits to customers under the GUAs reduces materially. This might be achieved by increasing the proportion of PPB's allowance which is subject to incentives, thus to ensure the benefits to customers are maximised and the risk of costs arising for customers is minimised.

2.1.8. <u>Costs not considered in the analysis and decision</u>

2.1.8.1. CfD Risk Premiums

PPB sells CfDs in the forward market each year to help suppliers manage the risk of price volatility in the market and to lock in margin and reduce volatility in the PPB Amount and hence in the PSO Tariff. PPB is incentivised to transact such contracts under the PPB price control which helps add liquidity to the forward market. Suppliers are willing to pay a premium for the removal of the risk of price volatility, and there is an asymmetric risk that the SMP may rise further than it can reduce and we expect they will continue to be prepared to pay a premium because:

(i) the demand for CfD products always outstrips supply, and liquidity in the CfD market has been a constant topic of discussion since the introduction of SEM;

(ii) Suppliers are willing to pay a risk premium in order to procure hedging products which mitigate against financial distress of their business. Generators have alternative mechanisms for managing their cash flows and, instead of hedging, can ensure their underlying spot commodity charges are paid after receipt of their spot electricity revenues; and

(iii) Suppliers are prepared to pay considerable risk premiums for peak products as there are material factors which could negatively impact on SEM pricing such as major forced outages.

The premiums captured by PPB each year from the sale of CfDs can be identified by the “Mark to Market” value of the CfDs (and associated gas hedges). PPB provides this information to the UR each year as part of the PPB Amount tariff submission.

The evidence clearly highlights the premiums suppliers have been willing to pay and PPB suggests that a prudent assessment of the value for future years would be £2m to £3m per annum.

2.1.8.2. Credit Cover costs for Power NI

Cancellation of the GUAs will have a significant impact on the cost of providing credit for Power NI in both the SEM and in the CfD markets. Power NI benefit from being part of the same legal entity as PPB. PPB is required to maximise the use of Settlement Reallocation Agreements in the SEM to minimise the cost to Power NI of providing credit cover to SEMO. Similarly, credit support is required for all CfD transactions and if the GUAs were cancelled, Power NI will have to secure all its CfDs from third parties with an associated requirement to provide credit support thereby increasing Power NI’s costs, which is an allowed cost under the Power NI price control and therefore would be an increased cost for customers.

This additional cost to Power NI would be passed through to customers (and where other suppliers benchmark against Power NI’s prices, to their customers).

PPB also provides the most favourable credit terms in the CfD market which reflects the additional protection provided by PPB’s Payment Security Policy (agreed with the UR) and were the GUAs cancelled, other suppliers may need to post higher levels of credit, which we would expect will be passed on to customers.

2.2. Economic Analysis - Results

PPB's analysis shows the value of the remaining CCGT GUAs to be substantially economic for Northern Ireland customers. Our comments in the previous section identify areas where the UR's analysis is incorrect or has failed to take proper account of value for customers and which therefore produces erroneous results. A summary of the results of PPB's detailed analysis is set in Section 3 below.

The UR's analysis also "extrapolates" results for nearly half of the period (four out of nine years) which is not a rigorous basis upon which to make any decision.

The UR's results are also significantly different to the analysis it included in its 30 April 2012 decision paper in relation to the Possible Cancellation of Generating Unit Agreements in Northern Ireland. That paper stated[5] that "These results indicate that the GUAs for the Ballylumford CCGT units are expected to remain beneficial for consumers over the remaining lifetime of the contracts". This analysis, although also not properly taking account of many of the same omissions in the current analysis, indicated the aggregate value of the CCGT GUAs in the base case to be c£79m (for the nine years from 2015 to 2023), which compares to the current base case which shows an aggregate cost of c£35m[6].

There is no explanation for this £114m swing in value and an examination of the relative commodity price curves indicates that while coal prices have reduced by c30% and gas prices by c5%, the change has no effect on the merit order as coal was the baseload generating capacity in 2012 and remains so. Similarly, the plant new build and closures show little variance and indeed wind capacity has not commissioned as quickly as anticipated which would be expected to improve the value of the GUAs.

In relation to the sensitivities, the UR's analysis shows that High Gas prices makes the GUAs even less economic for customers. However this result is counter- intuitive to what would be expected when gas is already more expensive than coal generation. As high gas prices will not change the merit order, the only change would be that the relative costs of the gas fired plants would diverge slightly reflecting their relative thermal efficiencies. The consequence of this for a mid-merit plant should be that when it is marginal, it will still recover its costs and when a more expensive generator is at the margin, the unit's infra-marginal rent would increase. Hence, given that CCGT units are already mid-merit, the expected outcome of higher gas prices would be a slight improvement in the economics for the units. This intuitive outcome is confirmed by PPB's detailed analysis.

2.3. Policy Considerations

From PPB's engagement with customers and customers' representatives, electricity prices are clearly their primary concern and we believe that customers' interests are best protected where prices are minimised. Therefore where the GUAs provide economic value, cancellation would be detrimental to customers.

Furthermore, the cancellation rights provide a one way option for the Authority to cancel the GUAs at any time should they become uneconomic and therefore provide

[5] Paragraph 1.7

[6] Summary analysis for both the UR's 2012 and 2014 analysis is shown in Appendix 1

a one way hedge for customers who can capture all the upside while the contracts are favourable and can escape from any future burden through cancellation should the contracts become uneconomic at some point in the future with 180 days notice.

2.3.1. <u>The Promotion of Effective Competition (paragraphs 5.7 -5.20)</u>

2.3.1.1. New I-SEM Design

PPB disagrees with the hypothesis that the absence of the GUA arrangements could simplify the implementation of the I-SEM arrangements. As the consultation paper notes, intermediary arrangements will need to be designed in to the new market arrangements. Harnessing PPB's knowledge and expertise will ensure the market is fit for purpose for both PPB and other smaller intermediaries. PPB's involvement during the design of the SEM ensured the market was developed with sufficient flexibility to ensure many other participants have been able to participate without the need for material changes to the market rules. Hence PPB's involvement has been pro-competitive and we believe the same would be true in the design of the I-SEM.

PPB totally disagrees with the conjectural statement that the existence of GUAs isolates the power station owner from signals to upgrade or operate each unit more flexibly. Conversely there has been evidence following the cancellation of other GUAs that generators have delivered less flexible arrangements.

The GUAs were designed with the maximum flexibility in mind and PPB seeks to maximise the offering of such benefits to the system and has been at the forefront of the development of the ancillary service market. PPB suggested the introduction of the new reserve products, which PPB contracted from November 2013, which allow the System Operator and the Service Provider to agree services in excessof the original contracted values. This technical and commercial ingenuity provides solutions for optimising both dispatch and the flexibility afforded by generating units.

PPB has also offered open cycle mode operation to SONI since the beginning of the SEM. SONI and Eirgrid recently held an exercise to procure Flexible Mode Operation from Generators. Three proposals were received including one from PPB which would replace the existing agreement with SONI. We understand the proposals received from the two other generators have been rejected by the TSOs.

It is also worth noting that PPB offers its units to the market more flexibly than other similarly configured CCGT units and PPB trades CCGT20 as two generating units in the SEM each with a minimum generation of 113MW on combined cycle and 66MW on open cycle. It is therefore demonstrably clear that the existence of a GUA has not impeded the efficiency of the market.

These examples provide real evidence that PPB continues to offer the greatest flexibility in the market in operating CCGT plant.

PPB agrees that the continued existence of the GUAs will provide a level of insurance for NI customers through the design of the I-SEM, both from the perspective of applying PPB's knowledge and experience in the design phase and also to offset any adverse effects that may unexpectedly arise. PPB also provides considerable expertise at other fora in Northern Ireland. For example PPB is taking a leading role in the adoption of the EU Network codes to ensure compliance with the codes.

2.3.1.2. Contract Liquidity

PPB does not believe cancellation of the GUAs would increase liquidity in the contract market and given the relative coal and gas prices, there is unlikely to be any portfolio effect which was of some benefit when the production costs of coal and gas fired units where similar. PPB also offers CfD volumes against its constrained output and therefore there is a risk the CfD volumes offered in the forward market could reduce.

PPB aims to hedge 75-80% of its forecast constrained dispatch. As the Ballylumford CCGTs currently have a market load factor of 10%-20% and a constrained load factor of around 30%, using the constrained dispatch for setting CfD volumes increases PPB's market offering up to 0.75TWh p.a.

The one outcome which is certain, in relation to the contracts market, is there will be a reduction in sellers in this market. Given that ESB, PPB and AES are the only current participants selling on the Tullett Prebon platform a reduction to two sellers is a major change in market concentration. This increase in market concentration in the forward markets must be given serious consideration as the exertion of market power could be materially disruptive to suppliers and to retail competition and to the long-run cost to customers. Volumes sold in the CfD market change from year to year – however with levels at circa 50% of the spot market the contract market has the potential to have a material negative impact on competition and new entry in both the retail and wholesale markets. Whilst the UR has considered contract liquidity, no mention has been made of market concentration. Market power could be exerted in terms of offer/reserve prices or requested credit terms. This clearly highlights that cancellation creates additional risks for customers.

2.3.1.3. Market Power

PPB agrees with the analysis that clearly demonstrates that cancellation would create significant local market power concerns in N. Ireland.

Avoiding concentration is clearly much superior to trying to develop mitigation measures to deal with the effects of concentration that can be avoided. The requirement to develop the I-SEM to comply with the EU Target Model requirements also means that mitigation measures, such as the Bidding Code of Practice, will have to be relaxed and this therefore increases the risk that mitigation measures may be more difficult to design. This highlights that the avoidance of concentration is a much better approach.

It is also incorrect to state that the decision on cancellation will have no impact on market power. A larger un-contracted generation portfolio will clearly increase the scope to benefit from market power. PPB also constantly monitors the generators behaviour to ensure compliance with the GUAs and hence may identify any such actions much quicker than, for example, the TSO. There is also a significant risk that the generator could exert market power to influence its position in the CfD market and the existence of the GUAs significantly dilutes this risk.

Northern Ireland requires locally connected generation to provide: inertia; spinning reserve; voltage support and black start capability. This provides significant power to an entity which has the majority share of the installed capacity of conventional generation in Northern Ireland.

2.3.2. Security of Supply, Diversity of Supply and Environmental Sustainability (paragraphs 5.21 – 5.23)

As noted earlier, cancellation would create significant local market power concerns in N. Ireland and given the material system constraints in Northern Ireland, such concerns must be given serious consideration. AES will become the only conventional generator that will be capable of providing voltage support for the greater Belfast area. Furthermore, during outages at Coolkeeragh Power Station, AES will also be the only material provider of inertia to the Northern Ireland system. AES will also have considerable capability to influence the level of renewable generation that can be synchronised to the Northern Ireland system. These issues could ultimately affect Security and Diversity of Supply and should form part of the wider assessment of the value of the GUAs.

The GUAs provide that higher levels of backup fuel can be required to be held at Ballylumford than is required by the CCGT’s Article 39 authorisation. Following cancellation we expect AES would reduce both the distillate stock holding. This has an obvious implication for security of supply in Northern Ireland, particularly as there are no fuel stocking obligations for Kilroot or on any of the other generating units at Ballylumford.

3. Summary of PPB's detailed analysis

PPB has undertaken a detailed economic analysis of the GUAs following the publication of the UR's consultation paper. This is based on monthly modelling through to September 2023 and is based on Commodity prices on 26 March 2014.

The analysis fully takes account of all the errors and omissions identified in the UR's analysis and reflects the current Commercial Offer Data submissions that are bid into the SEM. PPB's modelling also dispatches on both a constrained and unconstrained basis which provides for a full bottom-up identification of the costs and revenues.

The analysis demonstrates that the GUAs provide significant value for customers.

	Actual	£ milllions (2014 price base)										
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total yrs 1-5	Total
Base Case	5.2	9.6	18.6	21.7	21.8	20.7	24.3	27.6	29.5	24.9	13.3	**92**	**212**
Gas +50%	5.2	14.8	20.6	26.2	24.0	21.9						**107**	**107**
Gas -50%	5.2	24.8	31.6	37.3	44.9	41.7						**180**	**180**
Demand + 10%	5.2	20.0	25.5	25.9	29.4	25.9						**127**	**127**

PPB will provide the detail of its analysis to the UR and is concluding its analysis on the later years for the various sensitivities.

Conclusions

The results of the UR analysis as set out in the consultation paper, and upon which the UR's draft decision is based, surprised PPB. PPB's expectation is that the contracts would be maintained given both its own valuation and the value shown by the UR's previous analysis, which was published less than two years ago (in April 2012). There is a very significant gap between the UR's latest analysis which indicates an aggregate cost for customers of c£35m compared with both the UR's previous analysis which showed the costs to be provide a £79m benefit for customers and PPB's latest analysis. Furthermore, the negotiation concluded in 2000 sought to capture the benefit for customers of low cost capacity from April 2012 once the availability payments reduced by 60%. We would have expected the UR to examine in detail the underlying factors giving rise to such a material change in its valuation, not least as a sense check on the analysis.

Modelling of the electricity market, and the value of the GUAs within it, is complex given the range of factors that influence it. A decision to cancel the GUAs is irreversible and hence an incorrect decision has major consequences for electricity costs for customers. Given the finality of a cancellation decision, it is imperative that the decision is based upon rigorous and robust economic analysis of all of the costs and benefits to Northern Ireland customers. This analysis must consider the full range of potential variations to assumptions, to ensure the information upon which any cancellation decision is made is properly founded and that the UR has met its legislative obligations.

The UR has provided us with the detailed analysis and assumptions behind its analysis and our review of the UR's assumptions and analysis highlights a number of material errors and omissions in basic cost items and in areas of value to customers that would be lost were the GUAs to be cancelled. This review indicates that the value to customers from these simple cost and revenue lines is understated by a minimum of £166m (as summarised in the table in Section 1) and inclusion of these within the UR's analysis would change the £35m loss to a £131m benefit for customers. This is before even considering the more complex Plexos market modelling where there is additional value for customers as, for example, the current analysis ignores the bidding in of gas capacity by non baseload generators in RoI which will result in inframarginal rent being under-valued. Once this is properly taken into account in the UR analysis, the value for customers will increase further.

It is also noteworthy that the GUAs are currently beneficial for customers as is evident from the fact that the PPB Amount was set to rebate c£3m (via lower PSO charges) to customers in 2013/14 tariff year while the actual position is that the GUAs have out-turned £6m ahead of forecast in the first 6 months of the year.

PPB has conducted comprehensive monthly modelling of the GUA value for the period to September 2023 and the results of this analysis show that the GUAs provide significant value for Northern Ireland customers totalling £202m (in 2014 prices) compared to the UR's estimated cost of £35m.

There is also considerable potential upside value in the GUAs with little downside risk. The sensitivities largely result in increased value for the GUAs. In addition, mid-merit gas fired generators are currently under-remunerated (e.g. the PSO in RoI increased significantly last year to support the Tynagh contract) and any rebalancing of this will improve the value of the GUAs. Similarly, any additional revenues arising from the DS3 proposals would enhance the value of the GUAs, as would a delay in the commissioning of renewable generation or unplanned outages on higher merit order generators.

This highlights the value skew in favour of customers which is supported by the effective one-way hedge for customers who can harvest any such additional benefits with the comfort that the GUAs can be cancelled with 180 days notice should, in the unlikely scenario, the GUAs become uneconomic for customers. This arrangement is a valuable asset for customers when the wholesale market is under-going potentially significant change and the GB market is experiencing tight generation margins. The retention of the GUAs provides a safety net for customers through this period of uncertainty.

On the wider policy considerations, PPB considers that prices are the primary concern for customers. PPB does not believe cancellation would materially simplify the new I-SEM arrangements and indeed the presence of the GUAs will ensure PPB’s knowledge and expertise will provide beneficial input into the design to ensure, for example, the role of intermediaries is appropriately provided for. PPB also disagrees that the GUAs in any way dilute the response to potential market signals and there is clear evidence that PPB has been the most responsive in such areas.

PPB considers there is a high risk that forward market liquidity could actually reduce as we understand PPB is the only participant that provides CfD volumes based on its higher level of constrained output.

As recognised in the consultation paper, it is very obvious that local market power would increase with cancellation of the GUAs and it must be recognised that this would affect not just the energy market but also the contract and ancillary service markets. Avoidance of market power is clearly preferential to enhancing it and then seeking to implement measures to mitigate it, particularly as they may be more difficult to structure in the I-SEM.

PPB concludes that the GUAs, even at a low point in the revenue streams of mid-merit generators, will provide significant benefits for Northern Ireland customers with scope for significant further upside and with low downside risk, which is in any event mitigated by the ongoing right to cancel with 180 days notice.

Appendix 1 : Summary of the results of the UR's 2012 and 2014 analysis

April 2012 UR Analysis - Commodity prices at end Jan 2012

		£000s									
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Aggregate Value £m**
Base 2012	**CCGT 10**	304	304	304	1,299	1,299	1,299	1,363	1,363	1,363	8.90
	CCGT 20	3,281	3,281	3,281	10,095	10,095	10,095	9,943	9,943	9,943	69.96
	Total	**3,585**	**3,585**	**3,585**	**11,394**	**11,394**	**11,394**	**11,306**	**11,306**	**11,306**	**78.86**
High Gas 2012	**CCGT10**	626	626	626	958	958	958	1,597	1,597	1,597	9.54
	CCGT20	113	113	113	3,928	3,928	3,928	7,138	7,138	7,138	33.54
	Total	**739**	**739**	**739**	**4,886**	**4,886**	**4,886**	**8,735**	**8,735**	**8,735**	**43.08**
Low Gas 2012	**CCGT10**	804	804	804	1,194	1,194	1,194	1,617	1,617	1,617	10.85
	CCGT20	11,983	11,983	11,983	12,421	12,421	12,421	16,523	16,523	16,523	122.78
	Total	**12,787**	**12,787**	**12,787**	**13,615**	**13,615**	**13,615**	**18,140**	**18,140**	**18,140**	**133.63**
High Demand 2012	**CCGT10**	558	558	558	1,631	1,631	1,631	2,351	2,351	2,351	13.62
	CCGT20	4,792	4,792	4,792	13,048	13,048	13,048	15,170	15,170	15,170	99.03
	Total	**5,350**	**5,350**	**5,350**	**14,679**	**14,679**	**14,679**	**17,521**	**17,521**	**17,521**	**112.65**
Low Demand 2012	**CCGT10**	161	161	161	804	804	804	1,201	1,201	1,201	6.50
	CCGT20	3,414	3,414	3,414	5,554	5,554	5,554	9,561	9,561	9,561	55.59
	Total	**3,575**	**3,575**	**3,575**	**6,358**	**6,358**	**6,358**	**10,762**	**10,762**	**10,762**	**62.09**

March 2014 UR Analysis - commodity prices at end Oct 2013

		£000s									
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Aggregate Value £m**
Base 2014	**CCGT 10**	-656	-226	-305	-384	-1,827	-1,653	-1,479	-1,305	-1,132	-8.97
	CCGT 20	-4,038	-2,652	-2,585	-2,519	-5,291	-4,053	-2,816	-1,578	-341	-25.87
	Total	**-4,694**	**-2,878**	**-2,890**	**-2,903**	**-7,118**	**-5,706**	**-4,295**	**-2,883**	**-1,473**	**-34.84**
High Gas 2014	**CCGT10**	-1,246	-1,004	-1,008	-1,012	-2,379	-2,181	-1,983	-1,785	-1,586	-14.18
	CCGT20	-9,359	-7,921	-7,480	-7,039	-9,436	-8,952	-8,469	-7,986	-7,502	-74.14
	Total	**-10,605**	**-8,925**	**-8,488**	**-8,051**	**-11,815**	**-11,133**	**-10,452**	**-9,771**	**-9,088**	**-88.33**
Low Gas 2014	**CCGT 10**	-642	-361	331	331	-686	-387	-87	212	512	-0.78
	CCGT 20	9,520	8,044	12,122	12,122	11,323	11,024	10,725	10,426	10,128	95.43
	Total	**8,878**	**7,683**	**12,453**	**12,453**	**10,637**	**10,637**	**10,638**	**10,638**	**10,640**	**94.66**
Merit order Flip 2014	**CCGT10**	-145	204	366	528	-674	-346	-17	311	640	0.87
	CCGT20	5,834	6,826	8,122	9,419	7,877	8,647	9,416	10,186	10,956	77.28
	Total	**5,689**	**7,030**	**8,488**	**9,947**	**7,203**	**8,301**	**9,399**	**10,497**	**11,596**	**78.15**
High Demand 2014	**CCGT 10**	-327	-197	-164	-130	-1,461	-1,316	-1,171	-1,026	-881	-6.67
(increase by 10%)	**CCGT 20**	-5,239	-1,809	-594	621	-1,001	-96	810	1,715	2,621	-2.97
	Total	**-2,006**	**-758**	**491**	**-2,462**	**-1,412**	**-361**	**689**	**1,740**	**1,740**	**-2.34**
Low Demand 2014	**CCGT10**	-780	-853	-756	-659	-1,926	-1,773	-1,619	-1,466	-1,313	-11.15
(decrease by 10%)	**CCGT20**	-5,524	-4,345	-3,786	-3,228	-5,507	-4,737	-3,968	-3,198	-2,428	-36.72
	Total	**-6,304**	**-5,198**	**-4,542**	**-3,887**	**-7,433**	**-6,510**	**-5,587**	**-4,664**	**-3,741**	**-47.87**

Appendix 2 : Summary of potential DS3 Ancillary Service Revenue increases (based on the TSOs' analysis)

	€ / MW	CCGT 10	CCGT 20	Total
Scenario A				
Minimum	€24,074	€2,551,844	€12,277,740	€14,829,584
Average	€30,217	€3,203,002	€15,410,670	€18,613,672
Maximum	€36,963	€3,918,078	€18,851,130	€22,769,208
Scenario B				
Minimum	€4,458	€472,548	€2,273,580	€2,746,128
Average	€25,197	€2,670,882	€12,850,470	€15,521,352
Maximum	€59,964	€6,356,184.00	€30,581,640	€36,937,824
Scenario C				
Minimum	€14,266	€1,512,196	€7,275,660	€8,787,856
Average	€27,707	€2,936,942	€14,130,570	€17,067,512
Maximum	€48,464	€5,137,184	€24,716,640	€29,853,824
Scenario D				
Minimum	€25,420	€2,694,520	€12,964,200.00	€15,658,720
Average	€31,038	€3,290,028	€15,829,380.00	€19,119,408
Maximum	€36,541	€3,873,346	€18,635,910.00	€22,509,256
Scenario E				
Minimum	€17,935	€1,901,110	€9,146,850	€11,047,960
Average	€27,475	€2,912,350	€14,012,250	€16,924,600
Maximum	€51,934	€5,505,004	€26,486,340	€31,991,344
Scenario F				
Minimum	€18,548	€1,966,088	€9,459,480	€11,425,568
Average	€28,465	€3,017,290	€14,517,150	€17,534,440
Maximum	€53,153	€5,634,218	€27,108,030	€32,742,248