Power NI Energy Limited
Power Procurement Business (PPB)

Exit Capacity Review for Northern Ireland Transmission

Call for Evidence

Response by Power NI Energy (PPB)

27 May 2016.

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Power Procurement Business

Introduction

PPB welcomes the opportunity to respond to the call for evidence in relation to TPA Solutions' discussion document on Exit Capacity Review for the Northern Ireland Gas Transmission network.

General Comments

The load factors of gas fired generators have reduced substantially and running levels are much more volatile as a consequence of energy policy decisions in relation to decarbonisation and the support provided to renewable generation with the objective being for 40% of electricity to be generated from renewable sources. The result of such policies is that there is a much greater requirement for conventional generators to operate flexibly to support intermittent renewables but this can only be efficiently achieved if there is equivalent flexibility in the gas arrangements to support the inter-dependency.

Customers ultimately pay for the cost of energy assets, be that electricity or gas infrastructure or power stations, and any such investment will require a reasonable return. The proposition that fixed gas infrastructure costs can be loaded onto electricity generators regardless of their load factor without any consequence is not tenable. The effect of high fixed costs will deter or delay investment which risks security of supply to customers or will require a separate contractual arrangement to support the investment. Where such generation locates outside N. Ireland (NI) then that removes the potential for any contribution to gas infrastructure costs which will be to the detriment of all NI customers.

Similarly for existing generators, lower load factors result in lower inframarginal rents that cannot support high fixed gas capacity costs and will create an incentive for generators to avoid such costs by alternative means, such as switching to back-up fuel on those few days where their generation volumes spike, to avoid paying for annual capacity. Such an outcome would also remove what would otherwise be a contribution to the gas infrastructure costs.

This issue of reducing generator load factors is also recognised across Europe and short term exit products are available in the majority of countries in Northern Europe[1] to provide the required flexibility.

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[1] See the recent Eurelectric position paper "Gas flexible exit capacity products" - http://www.eurelectric.org/media/272633/gas_flexible_exit_capacity_products_final-2016-030-0181-01-e.pdf

We believe exit products would improve the overall efficiency of energy markets and will assist in delivering least cost overall energy costs for consumers.

We do not accept that there would be any material system costs to introduce short term entry products. There is no requirement for auctions or exit nominations and hence all that is required is a system to capture exit capacity reservations with a simple settlement process based on the relevant capacity products held on any day, each charged at the applicable tariff rate, which is likely to be less complicated than the current ratchet mechanism.

Comments and Responses to the Specific Questions in the TPA discussion paper

Chapter 3. Assessment Framework

Q3.1: Is the basis for assessment appropriate?

PPB generally supports the assessment framework and welcomes the acknowledgement that "*the assessment needs to involve joined-up thinking across gas and electricity and across NI and RoI*". We are however concerned that despite the recognition of the need for joined-up thinking across gas and electricity, the paper fails to also recognise that the UR's statutory duties for gas are mirrored for electricity and hence any consideration cannot be isolated to just being a consideration of the gas duties. It is also essential to note that gas fired electricity generators in NI are the largest gas consumers.

Q3.2: Are the broader assessment framework and the specific criteria clearly articulated?

See our comments in response to Q3.1 above in relation to the broader assessment framework. We agree that the 3 specific criteria are criteria that require consideration although we disagree with the interpretations adopted and also believe that further criteria must be considered in relation to the wider gas/electricity inter-relationship and overall "energy" market efficiency taking a longer term consideration.

In relation to the interpretation of cost-reflectivity, we agree that network users should pay for their usage of assets, network and wider resources. However we disagree where such interpretation is selectively applied and, for example, this interpretation conflicts with the postalisation of charges and the fact that consumers such as Ballylumford who do not use any of the other transmission pipeline assets are nevertheless obligated to contribute to the recovery of the costs of those assets even though they have no usage of the assets or network.

We agree that the arrangements should encourage the efficient use of assets to ensure marginal net benefits are captured as a contribution to provide wider social benefits and to incentivise ongoing efficient investment. Our concern is that the inflexible approach to exit charging will incentivise less efficient outcomes for energy consumers as a whole as electricity generators will be incentivised to take steps to avoid charges, such as switching to distillate rather than incur large fixed gas capacity costs with the outcome resulting in greater overall costs for consumers given the gas transmission revenues are fixed and unchanged while the incremental cost of distillate over gas will be recovered in the electricity markets. Such an outcome would seem at odds with the UR's statutory obligations in relation to both electricity and gas given neither has primacy.

Q3.3: **If not how should the assessment framework be evolved?**

See the response to the previous question.

Q3.4: **Are there any other criteria which should be considered?**

The long-term sustainability of the energy industry (gas and electricity) in Northern Ireland needs to be considered to ensure overall efficiency in the energy arrangements. Any outcomes that discourage what would otherwise be efficient utilisation of the gas assets because of high fixed costs will result in further stranding of gas assets and disincentivise investment in generation in NI that will at some point be required, and, where investment in RoI is more attractive, it will require some form of top-up payment arrangement that will be a further cost on NI consumers.

Chapter 4. <u>Short term Products</u>

Q4.1: Are the 4 key arguments and the 5th consideration captured appropriately?

The first argument in relation to matching booking with utilisation is largely captured. We would however highlight that the charging for gas exit capacity is not based on any assessment of usage on the day of peak demand but on the day of the consumers' peak consumption. These are likely to be very different days and as we have already highlighted, even if the two events were likely to be contemporaneous, electricity generators have the ability to manage their consumption, e.g. by fuel switching, to provide demand side management that would be a more efficient overall outcome.

On the second argument relating to a level playing field, the issue is not limited to the availability of such products in RoI as there are daily and within day exit products available to generators in GB and in the majority of countries in Northern Europe, against whom all generators in NI will be competing in the coupled Day Ahead and Intraday electricity markets.

The fifth argument in relation to classification of gas costs in the electricity regime doesn't capture the fact that exit costs would be a variable cost until they are incurred after which they are sunk costs. Therefore it is possible for such costs to initially be bid in given they could be a marginal cost at the commencement of the gas year.

Q4.2: Is the analysis appropriate? If not please explain what is missing and how such argument and analysis should be reflected in any recommendation?

In relation to the first argument, we would question the comments on the "redistributions within the regime", which presumes the regime is correct in the first instance.

In relation to the analysis on the level playing field with RoI competitors, while it is correct that different rates may apply, there is no requirement for them to be equal. If this was the case then that would equally be a requirement before any coupling of electricity markets that has an objective of more efficient scheduling of interconnector flows across borders yet within each of those countries, there will be different fiscal policies that impact on energy costs but which has not impeded the EU wide requirement to couple markets.

It is also clear that not providing exit products in NI creates a further wedge in any investment case for generation in NI relative to investment in RoI or GB.

In relation to the consistency with entry arrangements analysis, we disagree with the analysis that the entry arrangements were introduced to address a very different problem. We consider the same arguments apply at exit and we note increasing industry consensus in Eurelectric on the need for flexible exit products to help gas fired generators manage reducing load factors as their role becomes more aligned with supporting renewable generation. Ireland always experiences such issues in advance of them impacting on the European grid and markets and hence it is a more critical requirement for NI.

We also disagree with the analysis that there is benefit from accommodating diversity at entry but not at exit (on the basis there is no diversity at exit). Diversity at exit will emerge as generators adopt alternative approaches, such as fuel switching, to avoid exposure to annual fixed costs when the generators are only running spasmodically and may not even be contributing to the peak gas flow day.

In relation to the analysis of the cost classification argument, we disagree with the assertion that the multipliers and factors are secondary to the existence of products. The pricing needs to be proportionate and should not be penal or at levels that distort efficient booking decisions.

Q4.3: Are there any other critical considerations that have been missed? If so, please respond by stating the argument, providing supporting analysis and evidence, and suggesting how it should be reflected in the recommendation.

Nothing other than as we have outlined above in relation to the geographic extent of competitors against whom NI generators are competing, which spans beyond RoI to GB and beyond that to the majority of countries in Northern Europe following the commencement of the I-SEM.

Q4.4: Are the assessments of the case for short-term products appropriate with regard to the specific criteria? If not please explain in your response.

We disagree with the assessment on the appropriateness of solving an electricity problem with a gas regime change. The two issues cannot be considered in isolation and the UR has statutory obligations for both electricity and gas. The assessment that it would be prudent to wait until the I-SEM is implemented is flawed since the same commercial outcomes are likely since the rational outcome in a competitive market would be for costs to reflect marginal costs, and additionally, the SEMC indicate in their recent market power decision paper (SEM-16-024) that they plan to impose obligations on bidding for 3-part bids into the balancing market. Hence there will be no change to the market fundamentals in relation to bidding and hence the discontinuity must be addressed now.

In relation to the question on the risk of losing generators as gas customers in NI, we believe this is a major issue and the imposition of a fixed gas capacity cost for generators that operate at low load factors (which will be further reduced if the renewables target is to be met) will mean generators will not invest in NI. We have already outlined that existing generators will consider options such as fuel switching to backup fuel to avoid incurring high fixed costs for capacity that is mostly unused the rest of the year.

A further simple appraisal of this risk can be made by considering the BNE peaking unit that has a capacity of c196MW. The annualised cost of this unit is quoted in the current consultation paper (SEM-16-026) at €85.08/kW/per annum. This covers the investment cost, return on the investment and the annual O&M costs and equates to an annual cost of €16.7m or £12.8m. This is a distillate unit but assuming the cost is broadly equivalent, if this unit were to operate on gas, it would have a maximum daily gas consumption of 500k therms. The charge in 2015/16 for this exit capacity would have been c£4m yet for which the unit would not earn any offsetting market revenues. This represents an increase of over 30% relative to the base annual revenues otherwise required to remunerate the peaking unit. Clearly any investor contemplating such an investment could not make the project viable in NI and would locate the unit in RoI or GB where it could avoid such £4m annual cost.

We note the references to the existence of GB exit products which indicates that GB accepts the need for such products and the arrangements must be considered equitable and cost reflective since otherwise they would not have been approved by Ofgem.

The statement that introducing STC products will increase electricity prices is disingenuous and reflects a very short term assessment that will not be in the overall interests of customers. The above example on the additional £4m cost for a peaking unit in NI means such capacity that will likely be required in the next few years to replace closing capacity, would not materialise if only annual exit products and charges are available with the likely consequence that side payments will be required to secure the investment. This would result in higher overall energy costs for NI consumers and would be an inefficient outcome that would not be in accordance with the UR's statutory obligations.

In relation to the assessment of whether the introduction of STC products would be a no regrets option, it is clear that most countries in Northern Europe already provide short term exit products and Eurelectric are indicating that it is essential those countries who have not yet introduced the products need to do so urgently. The drivers are reducing load factors and the requirements for flexibility to support unpredictable output from renewables which is not as severe an issue on mainland Europe as it is in an island system with high renewables targets. Hence the need for such flexible exit products is even greater in NI and should be expedited. The issue of complication of tariff setting and revenue uncertainty are not unique to NI and are already managed in RoI, GB and in the other EU countries that offer short term Exit products.

We do not accept the assertion that the introduction of exit products would be any more complicated than the introduction of entry products. Similarly, entry products have already been priced and it is unclear why the cost allocation for exit products would be any more difficult. We assume the pricing of Entry products complies with the UR's statutory obligations and it is not explained why the derivation of pricing for Exit products would be more problematic.

As already noted above we strongly disagree with the assertion that the problems caused by high fixed exit capacity costs is a matter for resolution in the I-SEM. The key issue is that such a charging approach incentivises less efficient decisions in relation to both investment and fuel usage that will result in higher overall energy costs for NI which is the real perverse outcome.

The issue that is troubling is that the authors of the report ignore the fact that customers ultimately must pay for both the gas infrastructure and investment in generation assets that are required. Increasing the cost of investment for generators adds risk and also risks over investment in gas infrastructure, both of which will increase costs for consumers.

Comments on the Initial assessment against the specific criteria

We disagree with the assessment in relation to cost reflectivity. Even before considering short term products, it is not cost reflective to charge based on an "option" that may not be co-incident with the day of peak gas consumption. It is also unclear whether the authors consider the existence of short term exit products in RoI, GB and beyond to not be cost reflective.

The argument in relation to the difficulty of setting multipliers is flawed given the same issues exist for Entry and there has been no indication that that has caused any material problems. Hence it is not apparent why exit products would be any different.

We agree with the statement that the efficiency of the network would be improved if off-peak load was to connect as that would contribute to overall costs without imposing additional capital costs. However, that is exactly the service that electricity generators offer. Their gas consumption may not coincide with the peak gas day and they can provide demand management by switching to backup fuel if necessary (and in most cases are obligated to be able to do so).

For many of the reasons already discussed above in relation to the overall efficiency of the electricity and gas markets and their need to interact efficiently, we disagree with the conclusion that the effect on competition is negative.

Chapter 5. ***Capacity Booking Responsibilities***

We have no comments on this chapter.

Chapter 6. <u>Capacity Booking Platforms</u>

Q6.1: Are the arguments above captured appropriately?

It is not clear if PRISMA could be used as the capacity booking platform. The main requirement is a simple system to capture trades (we understand the RoI uses the GTMS system that was previously used in NI). The analysis fails to identify that there are already systems in place to perform the remainder of the required processing for Entry products, including billing and settlement. We would expect that these systems could also be used for Exit products in the same way they are used for Entry products.

Q6.2: Is the analysis appropriate? If not please explain what is missing and how such argument and analysis should be reflected in any recommendation?

As noted in relation to the previous question, there has been no consideration of the other systems already utilised for all the other short term Entry capacity products for the functionality not provided by PRISMA. There is no obvious reason why existing systems could not also be used for short term Exit products given the similarity with Entry products. Furthermore, as there are no auction requirements or nominations at Exit, the rules and arrangements could be even simpler.

Q6.3: Are there any other critical considerations that have been missed? If so, please respond by stating the argument, providing supporting analysis and evidence, and suggesting how it should be reflected in the recommendation.

As noted above, the only reference to systems is to the PRISMA system and other existing systems are not mentioned. There is also no consideration that there is no need for nominations in relation to Exit and this simplifies many of the rules and validations required. At its simplest, all that is required is to record the exit products booked/reserved for any given gas day with any shortfall between actual daily exit volumes and the pre-purchased capacity being deemed to be a within day product. The actual exit capacity charges would then be billed on the basis of the different exit products held with the relevant price applied. We understand the GTMS system is used in RoI to manage the reservation and settlement of exit products.

Q6.4: Are the assessments of the case for using PRISMA for the booking of exit capacity appropriate with regard to the specific criteria? If not please explain in your response.

We consider the changes that would be required would be minimal given all that needs to be recorded is the capacity holding of any exit product held for each exit point. Settlement would then simply need to apply the relevant rate to each of the capacity products. This may be a more simple process than the existing ratchet mechanism.

Chapter 7. *<u>Ratchets</u>*

Q7.1: Are the arguments above captured appropriately?

The arguments are based on a false premise that certain gas customers can accurately forecast their gas requirements. As we have already identified above, the market load factors of many gas fired generators is now that of a peaking or low mid-merit generator. The actual load factor also depends heavily on how the TSO decides to dispatch generators to meet system constraints, on the intermittency of wind generation and on the availability of other generators. Hence gas fired generators in NI could have massive swings in their gas requirements for reasons outwith their control.

This is very different to the consumption of retail gas customers that is predictable to a reasonable degree of accuracy. Hence the objective of "accurate" reservation of exit capacity is unachievable for some gas fired generators. The electricity TSO may be better placed to estimate how they will operate the system and hence the daily volumes they expect but there is no mechanism whereby they would indemnify a generator who committed to exit capacity that is not required because circumstances change and the TSO changes its dispatch decisions.

This demonstrates the inequitability that exists in relation to being able to forecast demand. The consequences of wider energy policy, such as in relation to decarbonisation and high renewables targets, imposes high levels of uncertainty and potential volatility on the daily gas volumes of low load factor generators which must be recognised. The requirements for flexibility in generation to support intermittent renewables has a major impact on conventional generators and the gas arrangements need to be consistent and supportive of the wider policy if the overall energy costs to customers are to be minimised.

Q7.2: Is the analysis appropriate? If not please explain what is missing and how such argument and analysis should be reflected in any recommendation?

As noted above, the analysis ignores the fact that wider energy policy has created an electricity market within which generators have great uncertainty over potential daily gas requirements. In a centrally dispatched market that is heavily constrained, there are many factors not within the control of the generator that create the scope of large volatility. This must be accounted for in the gas arrangements and is a key reason why short term exit products are required.

Q7.3: Are there any other critical considerations that have been missed? If so, please respond by stating the argument, providing supporting analysis and evidence, and suggesting how it should be reflected in the recommendation.

See our answer to the previous question.

Q7.4: Are the assessments of the case for an enhanced ratchet mechanism for the booking of exit capacity appropriate with regard to the general considerations and specific criteria? If not please explain in your response.

We disagree with the assessment relating to cost reflectivity that states “there will be a tendency to under-book”. This relies on the assumption that it is possible to accurately forecast volumes which, as we have highlighted, is not the case for many electricity generators. It is also important to recognise that such uncertainty is driven by wider energy policy decisions and it would be inequitable to seek to penalise generators when they are fundamental to helping deliver the wider policies. The imposition of penal charges adds further risk that will ultimately result in higher energy costs for customers (since investors still require a return and any additional costs will just increase the cost of participation that will need to be recovered).

We believe there should be short term exit products and therefore no ratchet mechanism would be required. Should the UR not introduce such exit products then we do not agree that a ratchet factor greater than 1 is required.

Chapter 8. <u>Commentary and Initial Recommendations</u>

We have highlighted in our earlier comments that exit capacity costs are not immaterial costs and the absence of STC products will distort energy markets to the long term detriment of customers. The statements in relation to cost redistribution are unsupported and take no account of higher charges that would be applied to STC products (similar to the current pricing for short term entry products).

The analysis concentrates on potential impacts of gas consumers (ignoring that power generation is the largest gas consumer) without fully understanding the inter-relationship between the electricity and gas markets and also misrepresents some of the issues. Energy policy has developed such that flexibility is required from gas fired electricity generators to support high levels of intermittent renewable generation. This flexibility has a number of costs and it is important that these costs are correctly attributed and reflected in prices to customers, otherwise the overall outcomes will be inefficient. This requirement for flexibility and the cost thereof must be reflected across all areas of the value chain to ensure reflective costs and the absence of short term exit products in the gas market to support such flexibility means the costs cannot be accurately reflected in the electricity market, thereby distorting electricity pricing and leading to wider energy market inefficiencies. This is not a sustainable market structure and will result in higher long term costs for consumers.

There are also unsupported comments in the paper in relation to short term products at entry enhancing profitability and that the introduction of similar products at exit may provide further increases. We do not recognise this profitability point and are concerned that the analysis overlooks the key issue relating to ensuring costs are correctly allocated to ensure that the provision of flexibility is appropriately reflected in both gas and electricity prices to the respective consumers. We note the statement in the paper that this is “not the focus of TPA’s remit” but this is clearly part of the remit of the UR.

We are also concerned with the proposition that consideration of exit products should not occur at this time but should wait until after the I-SEM market is operational. The fundamental requirement for flexibility exists irrespective of the wholesale electricity market arrangements and STC exit products should be introduced immediately to ensure the correct signals exist and the energy markets function as efficiently as possible.