Response to TPA Solutions Discussion Document

'Exit Capacity Review for Northern Ireland Gas Transmission - Call for Evidence'

15 April 2016

on behalf of

AES Ballylumford Ltd and AES Kilroot Power Ltd

27 May 2016

Queries to

Commercial Department
Kilroot Power Station
Larne Road,
Carrickfergus
Co. Antrim
BT38 7LX

1.0 Introduction

As a major stakeholder within the Northern Ireland gas market, AES Ballylumford Limited and AES Kilroot Power Limited (collectively "AES") welcome the opportunity to respond to the TPA Solutions Discussion Document - 'Exit Capacity Review for Northern Ireland Gas Transmission - Call for Evidence' of 15 April 2016 (the 'Paper').

2.0 Summary

It is the view of AES that the current regime for recovering capacity costs as applied at Exit points in Northern Ireland (NI) is no longer fit for purpose. With the drive to decarbonise and increasing penetration of variable / intermittent renewable generation, the load factors of many gas fired plants have decreased significantly in the last five years and this trend looks set to continue. Thus significant fixed costs are being imposed on generators who are seeing a significant erosion of their income as so they are finding it increasingly difficult to absorb such costs. In addition, given the disparity that exists between the capacity products available to generators in the Republic of Ireland (RoI) verses NI, there is a significant disincentive to site new generation in NI. In other words, AES believes the current Exit regime is a significant barrier to market entry.

Whilst AES accepts the current arrangements do not infringe the current EU Directive, the lack of flexibility and choice of exit products is at odds with the direction of the EU Target Model.

For a wider European perspective, we would refer the reader to the following Eurelectric Position Paper on Exit STC's (titled 'Gas flexible exit capacity products'):-
http://www.eurelectric.org/media/272633/gas_flexible_exit_capacity_products_final-2016-030-0181-01-e.pdf

Overall, AES is disappointed with the tone and balance of the Paper which, in our view, presents the case for introduction of Short Term Capacity products (STC's) as only for the benefit of the generators' and infers that other gas customers will be penalised. AES does not accept this is the case. We also believe that insufficient weight has been attached to the fact that, in terms of usage, the generators represent approximately two thirds of the customer demand. AES strongly believes that the introduction of STC's could also be of benefit to industrial and domestic suppliers, or indeed anyone with a variable demand. In particular, those with a high seasonal load swing could potentially more closely tailor their capacity requirement and pricing to reflect usage. Whilst seasonal pricing may not be attractive to all, it at least opens the possibility for more dynamic pricing which should help drive competition and niche products. We understand this issues this may cause in terms of complexity and added costs of systems.

The paper also infers that by bidding cost of STC's into the SEM, generators are seeking to recover costs by forcing an increase in electricity prices. In reality it is AES's view that a generators electricity market bid cost should be cost reflective of the service being provided and cost to the generator in providing that service. We also feel it is appropriate that electricity customers should bear these costs. It should be a function of the design of the electricity market to control electricity pricing. Therefore, whilst there is a strong link between gas and electricity, it should not be the function of the gas market to control electricity pricing. The gas market design should reflect the needs and demands of all gas customers and ensure there is no cross subsidy from one class of customer to another.

AES does not believe that the assessment process as presented in the Paper takes account of the change in load patterns of gas fired generators. In Ireland the renewable generation source is primarily wind which, by its nature, is variable in output. There is currently enough wind generation on the Island to exceed 50% of total system demand (other than at peak periods). However, because of the relatively small size of the Island, day-to-day and intra-day wind variability can be very significant. In other words, wind variability tends to have the same impact at broadly at the same time across the whole Island. Forecasting wind generation is notoriously difficult and accurate forecasts are limited to a four hour look-ahead. Even then actual availability of wind generation can be several tens of megawatts (and sometime hundreds of megawatts) in variance to what is predicted. Thus the electricity system needs fast acting conventional generation to be able to cope with volatility in other generation and currently the best option (and perhaps the only viable option when costs and environmental impact are considered) is gas fired generation. Traditionally most gas fired plants were operated as base load providers, but this has now changed dramatically.

For gas fired plant operated by AES, the annual dispatch load factor for our CCGT plant has fallen to less than 30%. Indeed, ignoring constraint, market dispatch would be approaching 20%. For our conventional gas fired Units, the annual load factor is of the order of 3%. However, due to co-incident forced outages of other generators, particularly on low wind-days, the actual peak daily dispatch of these plants can potentially be as high as 70% to 80% of their max. generation. With the current gas Exit regime essentially this means either by booking, or by application of the Ratchet, AES is being charged for a peak capacity product which is circa three times greater than the average utilisation at best and potentially more than twenty times greater at worst. In its current form, AES has no means to recover this substantial cost.

The Paper does briefly discuss the introduction of I-SEM and the changes this may bring in terms of what costs a generator can recover. Whilst it looks likely that generators could include annual gas transportation costs in their bids, this will likely only be the case for the Day-ahead Market. Current I-SEM design would indicate that the Balancing Market will have bidding rules similar to the current BCoP rules applied in SEM. Therefore, without change, low merit plant will still be in exactly the same situation since such plants will likely only be active in the Balancing Market.

AES is also concerned at the apparent lack of co-operation between the gas and electricity markets in NI from a Regulatory level down. Clearly there is a very strong interdependence, but we see electricity markets moving towards flexibility and fast acting response whereas the gas market design, particularly in NI, is geared to predictable steady load profiles. Also, there is strong regulatory co-operation in the design of SEM / I-SEM so that it is a best fit across NI and RoI, but the same cannot be said of the gas markets.

With the retirement of over 280MW of gas fired generation in NI in the next few years and the impact of Industrial Emissions Directive on other units post 2020, our view is that NI will need a new gas fired generator to ensure security of supply post 2020. However, given the absence of STCs in NI compared to RoI, the investment signal is to build in RoI resulting in a material risk that there could be significantly less gas fired generation in NI.

It is important to stress that AES recognises that the fixed and operating costs of the NI gas network need to be fairly recovered from all users. It is AES's view that the availability of STC's at both Entry and Exit alongside an appropriate pricing structure (including seasonal STC price weighting) will allow all gas market participants to find the best economic fit depending on the variability and seasonality of their load profile. We also believe that the introduction of STC's at Exit does not necessarily mean a transfer of costs from generators to other gas users but, if the status quo remains, the disincentive to site new generation in NI will mean a significant increase in costs.

3.0 Specific Comments on the Paper

3.1 Chapter 3 - Assessment Framework.

Q3.1) - Is the basis for assessment appropriate?

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

In AES's view they are not.

The chapter begins by listing the UR's statutory objectives and clearly places them in context.

Namely:

- TSO Revenue Recovery
- Consumer Interest
- Joined-up thinking across jurisdiction and energy markets (NI/RoI & Gas/Power)
- The relatively small customer base and the domination of power generation.

We agree with this approach but find it strange that, after outlining objectives and context, the paper sets its own criteria. While these criteria are related to the objectives listed no reason is given as to why these particular ones have been selected.

We accept that if electricity consumers (in what is an increasingly gas dominated market) are not factored in then the overall customer base is relatively small.

Q3.3) - If not how should the assessment framework be evolved?

Q3.4) - Are there any other criteria which should be considered?

As stated in our response above we believe that the assessment criteria is effectively covered through the UR's statutory objectives. We feel that the paper lacks balance with a recurring theme arguing that the flexible products provided in most competitive gas markets should not be available to NI Consumers.

The arguments in the Paper are presented as though generators are the only stakeholders asking for regime change. We don't believe this to be the case and we would contend that the benefits associated with the proposed changes would accrue to other stakeholders.

3.2 Chapter 4 - Short Term Products.

__Analysis Section of Chapter 4__

Bullet Point - Allows matching of booking with utilisation.

We agree that it would allow booking and allocation to be matched. However we would like to see some robust analysis behind the statement "network costs are mainly driven by the cost of peak provision." We accept that a component of the initial capital cost of developing the infrastructure is driven by the peak demand. However, we would argue that the cost of financing the project isn't.

It is interesting that the paper refers to a generator as an "infrequent user" without placing this in context. The concept of scarcity rent is not explored.

We agree that utilisation of the system in times of peak flow should incur a premium (unless a customer has purchased a fixed price option). We would remind the UR's that a generators revue and indeed its peak demand is dependent upon variable factors such as commodity pricing. In a centrally dispatched market, generators have no way of aligning 'expected' and 'actual'.

Bullet Point – Allows level playing field with RoI generators.

As far as we are aware flexible short term products are available in a number of European gas markets. As the EU moves towards price convergence under the Target Model it seems to us essential that NI follows.

We would appreciate some further explanation on the following assertion.

'Even if similar product structures are available a level playing field will only be delivered in the RoI and NI if gas capacity charges are the same.'

This seems to acknowledge that we currently don't have a level playing field and seems almost passive in tone. The EU Target Model is largely about price convergence through the removal of arbitrage. Different pricing regimes create arbitrage which can only be addressed by moving towards standardising around consistent products and policy direction.

Bullet Point – Better enables new NI generation.

The content of this sections lacks focus. We agree that the location of new generating plant will indeed be determined by many different factors. However, if we consider the investment decisions associated with a new plant, the current NI Capacity Exit charging regime would leave a 400 MW CCGT with approximately £100M of potentially stranded costs over a 20 year life. This would present a significant challenge to any financing effort and likely deter investment in NI gas fired generation. It is incumbent on all players, Participants and Regulators alike, to resolve investment hurdles as opportunities arise.

Bullet Point – Consistency with entry capacity arrangements.

We do not follow the argument as presented. We cannot see how the number of sourcing points is related to the type of capacity product offered by the TSO. Furthermore we believe that any arrangement at entry must be matched by similar arrangements at Exit as the customer needs at entry and exit are likely to be identical. The paper does not address the core issue – namely volatility in gas (electricity) demand.

We would reiterate that the small number of direct connections in NI represents approximately two thirds of the total gas demand and make the substantive contribution to recovery of gas network costs.

<u>Assessment Section of Chapter 4</u>

Bullet Point - is it appropriate to solve an electricity problem with a gas regime change?

At first sight this looks like siloed thinking and it is difficult to answer a question structured in this way. An electricity 'problem' is a gas 'problem' and vice versa – they should not be considered in isolation.

We see no reason to wait until I-SEM introduction to implement reform. The principle of marginal cost recovery has already been embedded into the I-SEM design as intermittent / variable generators are likely only to be active in the Balancing Market were the intent is to apply SRMC pricing rules.

Bullet Point - is there a material risk of losing Generators as gas customers in NI?

As the Generators are privately owned businesses it is impossible to say with absolute certainty at what point a generator may choose to exit the market. However if we use the example given earlier then £5M per year of potentially stranded costs for a marginal plant represents a significant risk, particularly in the context of the CRM uncertainty associated with the I-SEM and on-going global commodity volatility.

Bullet Point - is the introduction of STC a no regrets initiative?

It is not clear what is meant by 'no regrets' in the context of this discussion paper. We also note inconsistencies around how the relationship with the electricity market is dealt with. We find the Paper to be contradictory in places with expressions of concern about the potential impact on electricity consumers interspersed with statements implying these are issues for other work streams.

We do not accept perceived complexity as a reason for no action. Any decision should be based on a cost / benefit analysis across all stakeholders.

Regarding this extract: -

'In any case, it is somewhat troubling to the authors that the ultimate thrust of the argument in favour of change appear to be that gas consumers need not be too concerned about the uncertain distributional effects of STC because it is unlikely that non-generation users will have to pay more – it's just the price of electricity that will go up!'

AES would respectfully ask how the author arrived at this conclusion. A generator has no interest in increasing his bid costs in a competitive market. However costs must be recovered and the cost of providing peak gas demand must be fairly allocated to those who benefit.

Bullet Point - cost reflectivity.

Under mutual ownership / regulated return models, asset owners are guaranteed a return on their investment and there will always be an ex-post element to the charging mechanism to cope with over or under recovery. Our recommendation would be to increase the frequency of the ex-post adjustment from the current annual arrangement.

Bullet Point - effective network use and effective development.

The argument that no off-peak capacity product should be created because there is no off-peak demand is circular.

We disagree with the conclusion that STC's would diminish the ability to forward plan, in fact we are requesting such products for exactly this reason.

Bullet Point - Effective Competition

While lowering the cost of access should always be a key criteria for a TSO, we confirm again that our concern in this instance is not about lowered costs of access rather it is about cost recovery.

Also we note with some alarm the tone throughout the paper implying that NI Generators' lack of ability to compete is not a fundamental issue for the Gas market in NI.

Specific Questions raised in the Paper: -

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

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?

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.

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.

AES believes we have adequately addressed these questions in our responses to the individual bullet points above and also in responses elsewhere in this document.

3.3 Chapter 5 – Capacity Booking Responsibilities

AES has no comment on this section.

3.4 Chapter 6 – Capacity Booking Platforms.

AES has no strong view on whether PRISMA or a bespoke NI Platform should be utilised for Exit booking.

We believe in the context of a locally auctioned product not subject to the same rules as an IP, the analysis and assessments presented in the Paper are reasonable and essentially final choice should be based on what provides the best value for NI Shippers.

However, AES would question the need to auction Exit capacity and would suggest STC's could simply be offered at a fixed price for each product for any given gas year. We base this on our understanding that currently there is surplus capacity at all NI Exits. Clearly if this is not the case then consideration would need to be given to some form of allocation process and the current Market design would suggest auctioning as a fair and equitable means of achieving this. However, if we don't need to consider auctioning / allocation for the next few years, a relatively simple bespoke system should suffice.

3.5 Chapter 7 – Ratchets

In the analysis, consideration is given to a maximum hourly requirement multiplied by 24 approach adopted in GB for generator capacity booking. However, the electricity Market in NI (SEM) is fundamentally different in that it is a central dispatch model and therefore generators do not control their output and hence do not control their gas system usage (I-SEM will be the same in this regard). Therefore the adoption of any similar process based on commercial discipline of generators controlling capacity booking is not appropriate.

Given TSO cost recovery is regulated in NI, it seems inappropriate that any Shipper or supplier should be expected to pay for more capacity than they require particularly given any excess income earned is returned to Shippers as a bullet payment (or under-recovery charged as a bullet payment).

If STC's are introduced, because the generators are not in the control of utilisation, AES would not be supportive of overrun penalties if STC's are not available for booking on a 24/7 basis. Currently in-day auctions end around midnight and this effectively means the remaining five hours of overnight operation are estimated. With unexpected system disturbances the actual dispatch can be significantly greater leading to a shortfall in booked capacity which is outside of a generators' control. We would propose that if a Shipper exceeds their Exit booking, they should be charged the highest capacity product rate applicable to the period. Generally this will be the in-day rate. However, AES does recognise the need to ensure correct Shipper behaviour and if a Shipper continually relies on the above mechanism to true-up their capacity booking, then they should expect to be penalised.

Q7.1) - Are the arguments above captured appropriately?

AES would contend that there is a misunderstanding on how accurately a gas fired generator can predict their gas utilisation. As a centrally dispatched system, actual dispatch is outside the control of the generators. In addition variability of wind, forced outages of other generating plant (including interconnectors) added to fuel price variations and foreign exchange variations mean marginal plants are continually moving in and out of merit. The net effect is significant swings in utilisation, not only intra-day, but also from week to week, month to month etc.

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 eluded to above, from AES's perspective, the analysis does not take account of the increasing unpredictability in gas utilisation for a generator and the fact, due to the operational and business rules of the electricity market, the NI Grid Code etc., such utilisation is almost all outside the control of the generator. Due to the relatively small size of the electricity system in Ireland, it is untenable to allow generators a free hand to control their own dispatch. Due to increasing renewables penetration and the intermittency in their operation, there are increasing numbers of gas fired generators who have very load profiles, but a significant spread in absolute daily peak in any year compared to average gas utilisation. Such generators are vital to the operation of the electricity system, but will inevitably have low market income and as such high fixed costs are not tenable. The gas market must recognise the need for an appropriate product and price structure to allow these generators to survive and to attract future investment in gas fired generation. Not to do so will clearly lead to significant future increases in costs to other gas consumers.

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.

Covered in our responses above.

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.

Covered in our responses above.

3.6 Chapter 8 – Commentary and Initial Recommendations

Short Term Products

We note the reference in the first paragraph to reduction in generators gas capacity costs and the materiality of such costs within the range of fixed and variable costs that a generator must meet. In the view of AES this illustrates a fundamental misunderstanding by TPA regarding the issue at hand. The magnitude of annual capacity costs is in the public domain and in our view should have been included in this paper. We would strongly suggest that these costs are material.

There are numerous references throughout the paper to generator views. Certainly AES does not recognise some of the 'views' attributed to generators and is concerned that these are referencing verbal discussions and there has been a misunderstanding of points generators were seeking to make.

AES would reiterate that I-SEM development is happening in parallel with this work stream and given many of the I-SEM market design parameters are known now, there does not seem to us to be any reason to delay Exit reform.

AES does not accept the final conclusion that the case for Exit reform is weak. Conversely will believe that Exit reform and the introduction of STCs is consistent with EU markets policy, will ensure better alignment between the All Island gas and electricity markets and will ensure a more efficient, transparent and cost reflective basis for booking capacity and allocation of costs.

We are disappointed by the lack of robust analysis in the Paper and indeed we perceive there to be a lack of balance and objectivity. It is AES's view that the arguments for no change are predicated on a perception that the generators simply wish to push costs onto other system users. AES has stated previously and we reiterate that we accept the need for system owners to recover costs and generators must contribute fairly to these costs. However, in a significantly changing operating environment, the current Exit regime is not fit for purpose and is not tenable for gas fired generators. For a wider European perspective, we would refer the reader to the following Eurelectric Position Paper on Exit STC's (titled 'Gas flexible exit capacity products'):-

http://www.eurelectric.org/media/272633/gas_flexible_exit_capacity_products_final-2016-030-0181-01-e.pdf

It is a long held view of AES that there is insufficient interaction and knowledge share between stakeholders in the gas and electricity markets from UR level down. We would encourage the UR to put in place fora or other appropriate mechanisms to ensure stakeholders from gas and electricity markets have a vehicle to openly share knowledge and issues with each other and also with the UR.

Process and next steps

AES would like to understand if Premier Transmission Financing plc (or any of the gas transmissions system owners) have financial covenants in place which may have an influence on, or would be directly impacted by, decisions on Exit reform.