



Generation & Wholesale Markets

**Response to:**

Consultation Paper “Access Tariffs and Financing the Gas Transmission System”

Reference: CER/13/122

ESB Generation and Wholesale Markets (GWM) welcome the opportunity to respond to the CERs Consultation Paper 13/122, *Access Tariffs and Financing the Gas Transmission System*. The main points of ESB GWMs response are summarised below. More detailed comments are contained in the subsequent sections. Due to the fundamental market changes proposed in the Consultation Paper and the significant impact to power generators, ESB GWM has submitted a detailed response outlining the potential negative implications of the CER's proposals.

## **Summary**

- ESB GWM agree that the gas transmission system needs to be adequately remunerated.

## **The Interoperability of the Gas Market and SEM Market**

- The changes proposed in CER/13/122 amount to a fundamental change in the structure of the ROI's gas market and will have significant detrimental impacts to SEM, potentially resulting in gas demand destruction, the creation of negative investment signals in electricity and the establishment of misleading market signals.
- No quantitative analysis or risk assessment of the proposed changes to different customer groups is contained in the consultation. Market participants would welcome a deeper review than that provided.
- The proposed restriction/removal of products contradicts the flexibility required from gas fired generators to achieve the government target of 40% renewable energy by 2020. Decreased flexibility is also counter to the EU Target Model for gas.
- Primary capacity bookings from shippers are decreasing due to a range of complex interactions in a changing energy market. We suggest that a more comprehensive review that acknowledges the interdependencies of the gas-electricity market is required. The review should address the reason why capacity bookings are falling and seek to implement a long term sustainable solution that represents the interoperability of both markets.

## **Equitable Remuneration of the Transmission System**

- CER/10/089 sought to address the "cross-subsidisation of the NDM sector by certain industrial customers and generators". In CER/13/122, the Commission suggests that NDM customers are cross-subsidising LDM customers. No analysis explains the change in the CERs position and the equity argument surrounding cross-subsidisation is questionable given generators full contribution to their connection and deep reinforcement cost in addition to providing commitments relating to their capacity bookings through the Large Network Connection Agreement. In comparison domestic customers do not contribute towards capacity bookings, do not contribute to any deep reinforcement costs and pay a standard connection charge. It is evident that different categories of customers are treated differently in relation to

connection policy. The CER needs to take account of these differences during any equity debates and ensure that any potential changes to the market structure do not impose an inequitable financial burden on a specific customer category

- The introduction of the EWIC has seen an increase in electricity imported from GB into the SEM market. The impact of this imported electricity is to potentially displace a CCGT from the SEM merit stack which in turn means that the ROI gas fired generator does not require exit capacity, which consequently leads to increasing transmission tariffs as the average unit tariff increases. In effect, ROI gas fired generators are paying for infrastructure that they are not utilising and cross-subsidising electricity imports from GB.

### **PC3 Process**

- During the PC3 process, WACC was set at 6.39% which had a significant impact on customer tariffs. The CER expects the WACC could fall for 2013/2014 to 5.2% as per the agreed PC3 formula. This will have a material impact on the revenues to be recovered by BGN and revenues would be expected to decrease in line with a decreasing WACC. Therefore, we feel that this consultation paper, which addresses structural changes in the market to offset BGNs revenue under recovery, should not be considered until the WACC calculation is complete and a clearer status of BGNs funding requirements are known.
- In CER13/034, BGN forecast a revenue under recovery of c.€37M for 2012/13. If the WACC decreases to 5.2%, our initial analysis suggests that this results in c.€40M reduction to BGNs revenue requirements over the PC3 period. This potential decreases of revenue requirements as a result of an updated WACC could be offset in year 2013/14 as opposed to over the five year period to immediately address BGNs revenue concerns. Revenue reprofiling needs to be considered as a potential solution.

### **Proposition to remove/restrict secondary transfers at exit and restriction on time of within day purchase**

- The proposal to remove all secondary transfers at the exit is a retrograde step and would lead to the removal of a functioning product which could be detrimental to the SEM customer. Removing secondary capacity transfers potentially threatens the viability of some plant and could ultimately lead to plant closures.
- In previous decision papers (CER/10/089), the CER sought to remove BGEs competitive advantage while simultaneously acknowledging the benefit secondary capacity transfers brought the gas-electricity market. We would suggest that secondary transfers remain in the market due to the valuable flexibility they provide to the electricity system considering the variability of wind generation and EWIC activity.
- The restriction of secondary capacity transfers and within day purchase to 09:00 on D-1 would destroy the alignment and interoperability that currently exists between the SEM market and the gas market. Generators do not receive indicative metered

generation data from the NCC until 16:00 on D-1. Therefore, the proposal to move the deadline to 09:00 results in an ineffective product that sterilises the market and provides no benefit to the user.

### **Conclusion**

- Revenue remuneration is important and is not an insurmountable task. A review that addresses the changing energy market and consequential changes to capacity bookings is required.
- This response outlines potential possible solutions for consideration in addressing BGNs revenue recovery other than those proposed by the CER including the introduction of a process whereby market participants can provide greater feedback to BGN in relation to BGNs capacity forecasting, revenue reprofiling, a review of the weighting attached to short term capacity products, examining the capacity:commodity ratio, analysing the impact of a decreasing WACC value and improving forecasting methodologies.
- We would urge the CER to implement a holding position at this point and to subsequently engage in a more comprehensive review in consultation with industry.

## **Section 1 Introduction and Background**

In January 2013 Bord Gais Networks (BGN) requested a mid year tariff increase to address a revenue recovery shortfall caused by a decreasing amount of capacity bookings in comparison to forecasted bookings. A number of contributory factors are listed in CER/13/122 including:

- Secondary capacity availability
- Decrease in the price of short term capacity during summer months in 2013
- Wind displacing gas in the merit order
- EWIC
- Coal and peat being more in merit than gas

ESB GWM feels that additional factors need to be considered when assessing the decrease in bookings including:

- Impact of recession and reduced demand
- Changing market signals that customers of the network are exposed to including running hours, scheduling and competition
- An underlying approach by shippers to their management of gas capacity in line with market arrangements more optimally aligning with the requirements of the power market & system

We agree that the gas transmission system should be adequately remunerated and that a review is required to identify solutions to address the revenue shortfall expected by BGN. This reflects the nature of regulated businesses but more importantly contributes to confidence in a highly regulated market and the Regulators themselves. Due to the complex cross market interactions expressed above, the issue of BGNs revenue under recovery requires a wider ranging review than that proposed in the consultation paper. Any review process should respect the need for buyers to manage their costs in their primary market. The needs of the power system are evolving and this has and will continue to have a direct and consequential impact on the level of capacity bookings. Thus, in order to implement a long term solution to BGNs remuneration, a more thorough and far-reaching review which addresses the interoperability of the gas-electricity markets is required.

The intermittency of wind generation in the electricity sector requires a fast acting response mechanism to be available from predominantly gas fired generators in the Single Electricity Market (SEM). Due to the intermittency of wind generation, two trends are emerging (i) large daily changes in the percentage of electricity generated from gas as a fuel source and (ii) a forecasted future divergence in peak gas demand and annual gas demand. For example,

evidence produced by the TSO at the CER Gas-Electricity workshop on the 3<sup>rd</sup> July 2013, illustrated that the percentage of within day electricity produced from gas changed from 30% to 80% on a given day, largely as a result of intermittent wind generation and EWIC imports. These changes have resulted in less baseload or predictable running for CCGT plants and make long term forecasting of capacity bookings by BGN more difficult. The evidence presented by the TSO regarding the variability and large daily swings of wind generation inherently enforces the requirement for fast acting responses from gas fired generators. This responsiveness from gas generators provides security of supply to the electricity market and ensures a stable, functioning electricity system and dynamic market. This flexibility has been managed to date and can be managed by BGN in the future. Gas capacity products must be designed to address the present and future needs of the gas and electricity system, instead of prohibiting the interaction of the two markets as flexibility is a key requirement in both the gas and energy market.

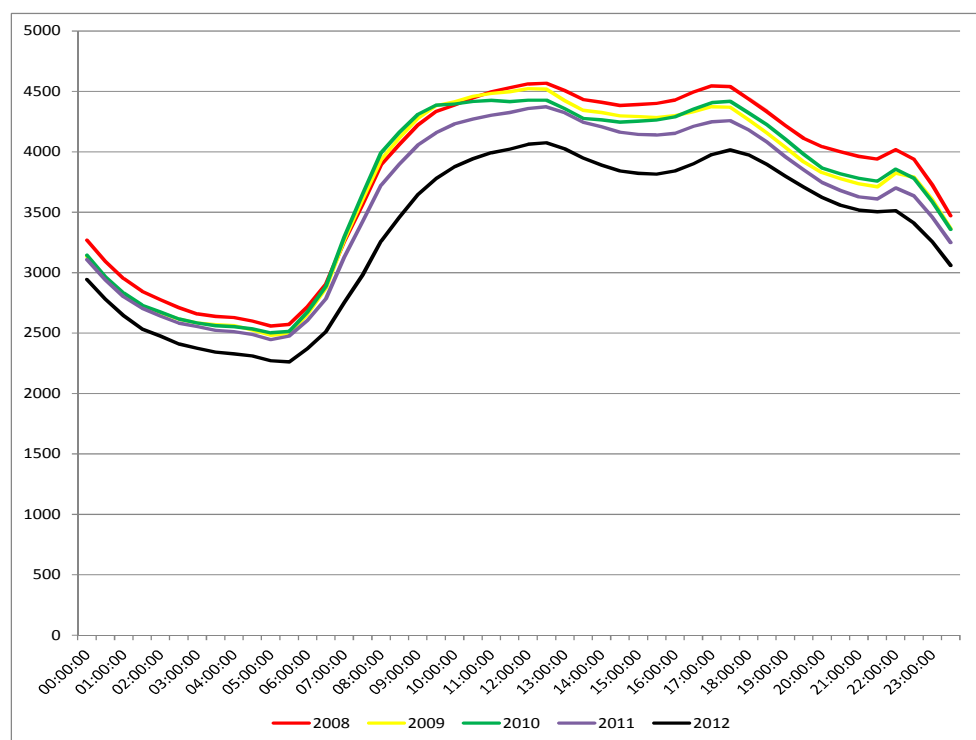
Removing secondary capacity transfers at the exit and within day purchases does not recognise or value the flexibility that gas fired generators are providing to the changing electricity sector. We would suggest that BGN seek to meet the needs of its' power generation customer base, by proposing new and innovative products that reflect the changing electricity market and meet the needs of generators that must react to this changing electricity system.

Since EWICs commercial operation, electricity has largely been imported from the UK into SEM, resulting in a potential 500MW decrease in demand from SEM generators and a consequential potential decrease in the requirement for gas capacity bookings. In effect, SEM gas generators are being asked to pay an increased capacity tariff in part due to the presence of an interconnector that reduces their running and ability to earn revenues. This amounts to cross subsidisation of infrastructure from one market participant to another and has not been duly considered in the scope of this consultation. There is also the need to ensure that true market signals are sent so that any continued increase of gas tariffs does not in itself become self defeating by incorrectly signalling the need for an additional interconnector in the electricity sector. Increased capacity costs and decreased flexibility in the range of capacity products available as well as restricted transfers will ensure that specific categories of gas plants will replace gas with distillate fuel and decrease capacity bookings further, if this is the cost effective solution. This prospect introduces the potential of a negative feedback loop of increasing unit tariffs leading to greater product substitution and resulting in ever increasing unit tariffs due to demand destruction.

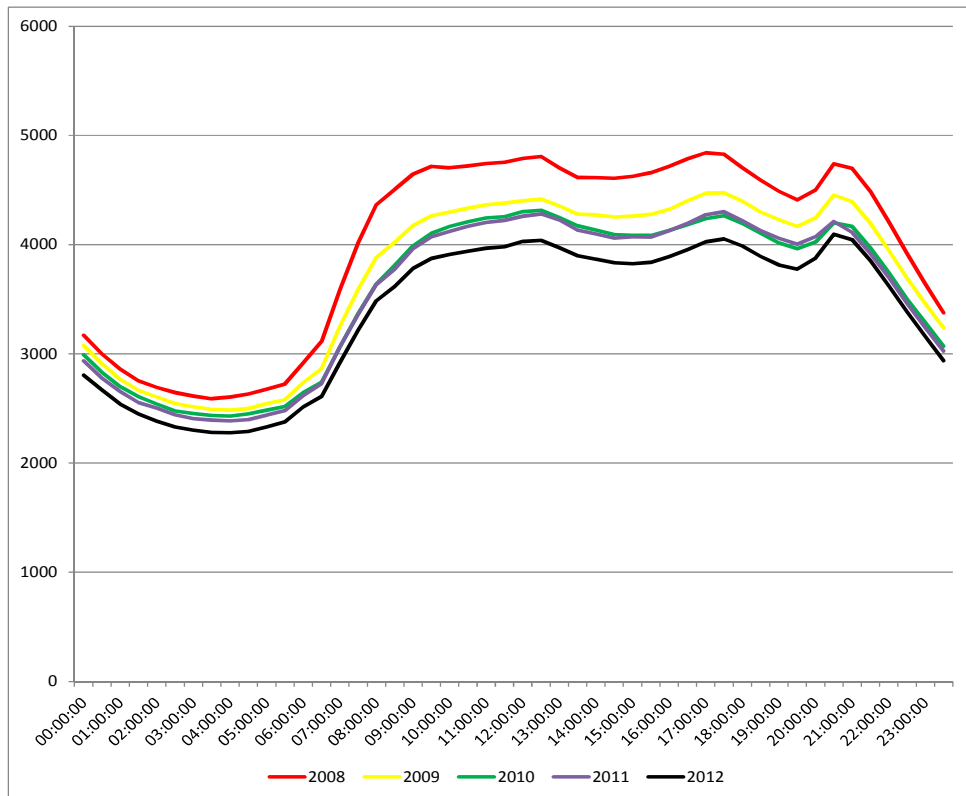
Due to the evolving requirements and structure of the SEM market, ESB GWM recognises the potential difficulties for BGN in forecasting capacity bookings. In general, BGNs general forecasting has been poor however the purpose of k factors is to mitigate the risk of

forecasting error over the PC3 period. An issue of concern is that BGN and the CER appear to want the revenue stream to be perfect in each given year. This is not a feasible reality as there will always be a measure of forecasting error. Unlike in PC2, PC3s consultation process did not include any demand analysis which would have provided valuable information to market participants. In April 2012 as part of the PC3 process, BGN submitted forecasted level of bookings expected for the period 2012/13 to 2016/17 and between April 2012 and November 2012, BGN made 2 revised forecasts of decreased bookings. BGNs forecasting ability needs to improve to prevent interim tariff increases occurring. The combination of factors responsible for decreasing primary bookings were present in the market place at the time of forecasting for PC3 and decreased bookings should have been anticipated. One potential solutions to assist in forecasting booking levels is the introduction of a process whereby market participants can provide greater feedback to BGN in relation to its capacity forecasting.

The economic climate and the impact of the recession on decreased electricity demand and capacity bookings must be considered as a contributory factor in decreased capacity bookings. Analysis shows decreasing demand since 2008 and it is important that the macro-economic environment is acknowledged when referring to decreased capacity bookings.



Historic Daily Demand Shapes – June 2008-2012



Historic Daily Demand Shapes – September 2008-2012

Reducing demand has also forced power generators to review and where possible continue to optimise its cost base and operations given the significant competition in the market. Depending on a shippers trading strategy and combined with a reduction in predictable running hours and the generators position in the merit stack, booking excess long term capacity bookings is not a commercial strategy that reflects modern market dynamics.

CER 13/122 seeks to establish a system with long term forecastable bookings however due to the fast response required from gas generators, a market consisting solely of long term exit capacity products, do not meet the requirements of power generators (one of BGNs most significant customers) or the electricity system as a whole. The introduction of these proposals would in effect be asking power generators to pay an elevated tariff for a reduced level of service. We believe that the CER must acknowledge the interdependence of the gas and electricity markets when determining the most appropriate and sustainable manner by which to address BGNs projected revenue under recovery. The product suite offered by BGN should be updated to reflect the demands of its customers. Proposing to remove the existing products which fulfil the needs of the majority of customers is introducing regressive market changes.

This consultation lists 3 potential mechanisms to address BGNs revenue under recovery: (i) raise network tariffs (ii) structural changes on the demand side and (iii) reprofile revenues.



We believe that all of these alternatives have not been fully considered but it appears that BGN has a preferred approach (CER/13/034a) which is being put forward by the CER in this consultation. For example, in CER/13/034a, “BGN would therefore ask the commission to implement its original decision on restriction of the Secondary Market and would also state that the full removal of the secondary market is now justified and should be considered by the Commission” [page 2].

The current CER consultation concentrates on structural changes in the demand side. We would request that all avenues being reviewed are made visible to market participants to ensure a transparent and informed review can occur.

Secondary capacity transfers at the exit provide shippers with a mechanism to react to the dynamic needs of the electricity system and manage their risk and cost exposure in a commercial and competitive way. In CER/10/089<sup>1</sup>, the CER allowed transfers within the same customer sector ( implementation delayed until October 2013). According to the Commission in the decision paper, the ruling to allow secondary transfers within the same sector “will address the cross-subsidisation of the NDM sector by certain industrial customers and generators and ensure that the price of such secondary capacity transfers is no longer based upon that bought by BG Energy for its NDM customers.” This ruling sought to remove BGEs competitive advantage as BGE was selling unused capacity “both to itself in its role as supplier to non-NDM customers and to other Shippers”. This caused a scenario where shippers were buying secondary capacity from BGE while simultaneously trying to compete with them. The CER acknowledged that this process could potentially distort competition. The Commission ruled that allowing secondary capacity transfers from one LDM exit point to another was an efficient use of capacity.

The proposal in CER/13/122 to remove secondary transfers at the exit is not in any way linked to equity in the system. This is evident as the CER previously determined that “power-stations are, in effect, paying for the capacity booked for residential customers” [CER/10/089 page 9]. This illustrates that the CER previously believed that power generators were cross-subsidising the NDM market and is in direct contrast to the position advocated in the current consultation paper. Power generators require the flexibility that secondary capacity transfers allow and would seek a scenario where transfers will still occur between shippers but any undue competitive advantage of BGEs is removed.

The proposal to remove secondary capacity transfers at the exit results in the removal of an actively used product whereas retaining secondary capacity trading at the same geographic

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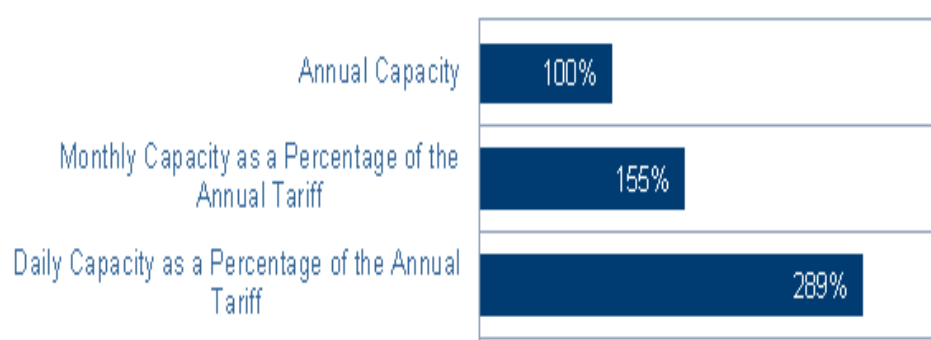
<sup>1</sup> <http://www.cer.ie/en/gas-transmission-network-decision-documents.aspx?article=14e5debb-5380-410b-9058-bd4d3f7a79de>

location results in an obsolete and redundant product remaining in the market. This issue is examined further in Section 3 Legislative Basis.

## Section 2 The Existing Regime

At present, gas capacity products available include annual and monthly primary exit capacity, short term exit capacity, secondary transfers of exit capacity and within day capacity. These products have been introduced in part to accommodate the changing demands from gas fired generators in ROI.

The regulated pricing of monthly capacity products and daily capacity products are excessive and make the products less attractive to participants. For example, purchasing daily capacity for an annual basis costs almost three times the price of an annual strip. To enable a more competitive and liquid market in short term products which will assist in revenue remuneration, it is suggested that the prices of these products is re-examined by the CER and that price flattening occurs. This price setting process is under the control of the CER. If more competitive pricing was introduced, this could assist in mitigating the impact of secondary transfers on BGNs revenue recovery. Modifying the price structure provides a quick and simple possible solution in addressing the revenue shortfall issue.



Specifically, in Code Modification A027, BGEs rationale for proposing within day capacity booking is to “facilitate interoperability of the Gas Market with SEM arrangements”. We believe that these products are still necessary to ensure the interoperability of the markets and that the removal of these products does not provide an appropriate, adequate or enduring means of addressing BGNs revenue shortfall. The proposed removal of these products is a retrograde step for the ROI gas market and will restrict liquidity.

The Gaslink Connection Policy Document<sup>2</sup> (Revision 2, February 2011) requires that large Industrial and Commercial customers (defined as those with a peak hourly demand greater than 50MW thermal input and a connection pressure of 16 barg or above) must cover the full capital costs attributable to meeting the customers requirements including any deep

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<sup>2</sup> <http://www.gaslink.ie/index.jsp?p=135&n=150>

reinforcements required. Power generators are paying 100% of the cost of their deep connection to the system as well as purchasing capacity and commodity products on the transmission system. As the Regulator is not taking these upfront, sunk costs into account, the equity issue discussed in CER/13/122 is incorrect as these upfront costs must be considered when ensuring that the system is remunerated in a fair and equitable way. The contribution of individual customer categories must be acknowledged when discussing the equity issue.

Power generators and large I&C customers pay significant capital costs which covers the cost of their connection to the transmission network. In addition, a Large Network Connection Agreement is required for large I&C customers as well as a portion of medium and small I&C customers (where the total cost of the connection less the customer contribution paid is more than €250K). According to the Connection Policy “Customers requiring a Large Network Connection Agreement will be required to commit to capacity purchases for a sufficient term to ensure recovery of the connection costs over and above the standard and supplemental economic test contribution. The volume and duration of capacity bookings required will be defined by Gaslink on the basis of the load profile requirements identified by the customer in their formal connection application. The requirement to commit to these capacity purchases will form part of the connection agreement.” If large I&C customers are required to pay the upfront capital costs associated with their connection in addition to committing to capacity purchases through the Large Network Connection Agreement, it is evident that they contribute significant sums towards financing the transmission system and that the CERs equity argument does not apply. In short, LDMs are paying significant costs for their connection and being able to manage their commercial exposure through the potential reduction of capacity bookings is a hedging mechanism which should be available for use in any competitive market. The burden of falling bookings is not falling disproportionately on NDM customers due to LDM decrease in capacity bookings as it is clear that LDMs have fully contributed towards their capacity requirements. If one considers the fact that power sector demand accounts for over 50% of peak day demand until 2021, a majority of the capital costs associated with new connections are recovered in advance of the customers connecting to the network. There are associated O&M costs and these are paid for through on-going payments for capacity with a 90:10 split delivering a significant sum. Similarly, as newly connected generators are required to commit to capacity payments this further reduces any risk to the transmission system caused by variability in forecasted and outturn capacity bookings.

In contrast, for medium and small Industrial and Commercial customers (defined as those with a peak hourly demand equal or less than 50MW thermal input and a connection pressure below 16 barg), connection charges consist of an upfront charge of 30% of the cost of connection, plus a supplemental charge based on an economic test evaluated over 7 years

where appropriate. The economic test considers the present value of the full connection cost estimate against the present value of the tariff revenue attributable to the facility. The purpose of the supplemental “economic test” is to provide for the shortfall in the remaining costs of the connection that would not be recovered through related tariff payments by the customer over the 7 year period. When the present value of the projected revenues is greater than or equal to the present value of the cost estimate then no supplemental contribution will be required. If the present value of the revenues is lower than the cost estimates, the connectee is required to make a supplemental contribution so that the NPV of the appraisal is zero. Therefore, small and medium I&C customers partially pay towards the cost of their connection to the transmission network and are also required to make an additional contribution if the outstanding connection costs are not recovered through tariff payments over a 7 year period. However, due to the recession some small and medium I&C customers would have decreased bookings compared to their forecasted bookings or potentially these customers may no longer be in operation. In these cases, it is the remaining customers that are potentially contributing to any revenue under recovery.

Domestic connections pay a standard domestic connection charge and may also pay a design fee if applicable. This charge would be relatively minor in comparison to the costs faced by large I&C customers. It is evident that different categories of customers are treated differently in relation to connection policy. The CER needs to take account of these differences during any equity debates.

CER13/122 forecasts that power generators will book 70% of its projected peak capacity in 2012/13 compared to 98% in 2011/12. The practise of utilising secondary exit capacity transfers and short term capacity is attributed by the CER to an increase in overall transmission tariffs for other users as fewer primary capacity bookings are made. However, as discussed in Section 1 of this response, increasing wind generation, the presence of EWIC and reduced demand due to recessionary impacts are additional significant contributory factors. Removing the flexibility in the gas market products available will not address the interaction between the contributory factors in decreased exit capacity bookings and so will not address the problem causing the revenue shortfall.

### Section 3 Legislative Basis

CER/13/122 proposes removing secondary capacity transfers at the exit (a capacity transfer is defined as an exit capacity transfer where a shipper transfers primary capacity from one geographic location to another geographic location). Secondary capacity trading at the same exit point (a single geographic location) would be allowed to remain. This proposal is a retrograde step for the liquidity and flexibility in the gas market and is a very narrow interpretation of the intent of Regulation 715/2009 (EC) which states:

Article 14(b) TSOs shall “provide both firm and interruptible third party access services” and (c) “offer to network users both long and short term services”.

Article 16 2(b) Capacity allocation mechanisms shall “be compatible with the market mechanisms including spot markets and trading hubs, while being flexible and capable of adapting to evolving market circumstances”.

Clearly the proposals to remove secondary transfers at the exit and restrict within day purchases is not aligned with this intent.

The Irish government has a target to achieve 40% renewable energy by 2020. To achieve this target, the electrical transmission system must accommodate 75% of instantaneous system non-synchronous penetration (predominantly from wind generation and EWIC flows). The ability for gas fired generators to act quickly in response to sudden increases or decreases in wind generation levels, is an essential means of ensuring a secure, sustainable power system in Ireland. This increased flexibility is required for gas fired generators to achieve this renewable energy target and DS3 (Delivering a Secure, Sustainable Power System) is an EirGrid initiative to ensure this system flexibility is in place. Removing the gas products which facilitates this flexibility in a cost efficient manner is counter-intuitive.

Section 9 of the Electricity Regulation Act outlines the Commission’s responsibilities regarding natural gas and protect the interests of final customers of gas (or electricity and gas). The Commission must consider that “Licence holders are capable of financing the undertaking of licensed activities”. Power generators are licence holders and the CER must give due regard to them when carrying out its functions. Shippers in ROI have a legitimate expectation that secondary capacity transfers at the exit and within day purchases of short term capacity are available in the market. We believe that the impact of the proposals in this consultation on property rights need to be duly considered by the CER.

The European Target Model for Gas Market is scheduled for implementation in 2014. The Target Model seeks to develop competition through the development of liquid hubs in

addition to efficient use of infrastructure, free shipment of gas between market areas and response to pricing signals allowing gas to flow where it is most valued. It also seeks to promote liquidity in gas traded at hubs. We believe that CER/13/122 is not in line with the broad principles of the Target Model as removing all secondary capacity trading at the exit and the potential removal of within day purchases of short term capacity at the exit removes necessary liquidity from the gas market. In addition, if these proposed measures are introduced in Ireland, a precedent is established which if adopted in Britain at the NBP directly restricts liquidity at a major hub which is counter to the European Target Model.

#### **Section 4 Restriction of Capacity Transfers at the Exit**

This is discussed in Section 5 Proposal 1: Removal of all Secondary Transfers at the Exit.



## **Section 5 Proposal 1: Removal of All Secondary Transfers at the Exit**

Since its introduction in 1998, secondary capacity transfers have proved to be a valued product providing a high degree of market flexibility. As secondary capacity is priced more competitively than short term capacity products, this product has resulted in more efficient costs to generators and more economic pricing for SEM customers. The removal of all secondary transfers at the exit would lead to the removal of a competitively priced, functioning product which actively benefits the SEM customer. The impact of removing secondary transfers at the exit and the consequential impact on SEM electricity prices is not considered in this paper but must surely form part of the greater debate.

As shippers for NDM domestic customers must book sufficient capacity to meet 1 in 50 peak day demand, the NDM market typically has spare capacity which historically was sold to other suppliers and shippers. CER/10/089 restricted transfers so that transfers could only occur between same customer sectors. This decision sought to remove BGEs competitive advantage while simultaneously acknowledging the benefit that secondary transfers provided to the gas-electricity market. In CER/10/089 the Commission stated that the sectoral restriction will “address the cross-subsidisation of the NDM sector by certain industrial customers and generators to ensure that the price of such secondary capacity transfers is no longer based upon that bought by BGE for its NDM customers” [page 33]. This is directly contradictory to the rationale in CER/13/122 for the removal of all secondary capacity transfers as “providing for the current levels of flexibility simply pushes the payment for infrastructure to those who are not offered any flexibility (NDM customers in particular)” [page 17]. No explanation or quantitative analysis has been put forward by the CER to adequately explain their changing viewpoint. The inflexibility of LDM customers paying for infrastructure despite the impact of the interconnector on the way LDMs use this infrastructure is not addressed in the consultation. If the equity issue is to be explored in a fair and equitable manner, then the reality of market conditions must be acknowledged and addressed in the review.

Primary capacity bookings from power generators have decreased but this is due to a combination of factors (less baseload or predictable running, introduction of EWIC, reduced demand, optimisation of booking strategy and the availability of secondary and short term products). To assume that bookings will transfer directly from secondary capacity transfers to primary bookings to such an extent that BGN will recover their revenue base is a simplistic and incorrect conclusion to a wider ranging problem. Removing secondary capacity transfers from the market threatens the viability of marginal plants and could ultimately lead to the closure of select power plants. The CER should be minded of the consequence of its actions on the commercial environment for generating plants. If these power plants cannot access capacity at commercially appropriate rates, the investment for continued operation of these plants is jeopardised and they may be forced out of the market. It is vital that the future

market signals are considered in determining any future actions. If removal of a product results in a scenario where new investment is not deemed possible, the capacity adequacy of the electricity system could ultimately be at risk as well as removing any revenue certainty for BGN.

Secondary transfers should be allowed to remain in the market due to the much needed flexibility they provide to the power sector. As outlined above, abolishing their existence will not solve the BGN financing issue. Removing this products leads to increased costs for generators through the purchase of more expensive capacity products and will ultimately be uneconomic. The CER should seek to protect and retain the flexibility that secondary transfers provide to the market as the efficient interaction between the gas-electricity market is vital in an evolving SEM landscape. A number of potential solutions exist to address the under recovery which will be discussed in Section 7. Alternative Options to Those Examined in This Paper.

We believe that the reference in the consultation paper relating to the impact of the secondary capacity regime on the Connection Policy does not reflect the full capital cost contribution (including deep reinforcement costs) that power generators pay for any of its new connections. By paying 100% of the cost of their connection to the transmission system, power generators are clearly paying for any additional incremental capacity to the transmission system. As large I&C customers are the only customers to pay upfront and in full for their connection cost, one must question whether it is equitable to remove functioning products which benefit the gas-energy market as a whole by reducing costs and allowing power generators to provide the required flexibility in a market where the amount of non-synchronous penetration continues to increase, in an attempt to recoup BGNs revenues. This is in effect, asking power generators to pay an increased tariff for a reduced array of products which does not meet their needs or the needs of the SEM. We do not believe that this is an equitable situation and would request that secondary transfers are allowed to remain within the market.

## **Section 6 Proposal 2: Restriction on the Latest Time of Purchase and Transfers of Capacity at The Exit**

In this section, the CER is proposing to move the deadline for purchase of short term capacity transfer to 09:00 at D-1. At present, within day short term capacity at the exit can be purchased until 03:00 in the trading day (as per Code Mod A042). Secondary capacity transfers can be purchased until 01:45 on the trading day. These Code Mods were established in recognition of the predicted movement of CCGTs to mid-merit due to increasing wind generation and the flexibility required from generators. The proposal to remove these flexibility products is a regressive and detrimental step in the development of the gas transmission system.

As outlined in ESB Trading's presentation at the CER Gas-Electricity Workshop (3<sup>rd</sup> July 2013), generators do not receive indicative metered generation (MG) data from the NCC until 16:00 on D-1. Thus, the proposal to move the deadline for purchase of short term capacity and the transfer of secondary capacity to 09:00 on D-1, would result in a market where generators would have no visibility on their expected running until 7 hours after the close of the deadline for purchase or transfer. Consider the implications of this; as the within day product is now effectively obsolete, generators will have the option of purchasing only annual or monthly capacity. For peaking plants that run for an unpredictable number of hours within a given year and rely on gas as a primary fuel, the prospect of having to buy long term strips of exit capacity will potentially destroy any remaining business case for the continued operation of these plants. Generators may decide to fuel switch which will further reduce the primary capacity bookings made or alternatively the plant may be retired. The potential of demand destruction is a very real consequence of this proposal. It undermines the investment certainty of one the key components of the SEM – the Best New Entrant (BNE). We would suggest that this proposal is withdrawn so that the existing structure which recognises the interoperability of the SEM and the gas market can continue to provide the necessary services to LDM customers and economic solutions for electricity customers.

If the deadline for purchasing short term capacity is moved to 09.00 at D-1, short term capacity products develop into an inoperable, sterilised product that provides no real benefit to the users. Altering the purchase deadline in this manner, effectively handcuffs the generators ability for effective cost and risk management and ultimately is detrimental to the SEM customers. To introduce a change of this nature is not acceptable in any market when its impact is known in advance of the proposed change and this impact will deliver an uneconomic position.

The prospect of Proposal 1 and 2 being jointly introduced is a prohibitive reaction in attempting to address BGNs within year revenue shortfall. It is short-sighted as it fails to

address the underlying problem while also disproportionately penalising power generators and providing no analysis, supporting evidence, risk assessment or claims regarding fairness or equity that stand up to scrutiny. As it does not solve the underlying problem, there is a very strong possibility that further interim price reviews would be required.

It is stated that BGN are experiencing revenue under recovery in the first year of the PC3 duration and this has subsequently resulted in an interim tariff increase and the current consultation. However, PC3 has a five year term with 5 year k factors. The process should be capable of recovering revenues through the k factors and not require such fundamental structural changes to the structure of the gas market.

If the market is changing then BGN needs to change too rather than attempt to revert back to a previous age. BGN should instead rise to the challenge and offer a greater number of products and services that can meet the needs of its customers.

## **Section 7 Alternative Options to Those Examined in This Paper**

The CERs proposed alternatives of mandatory bookings, removal of mandatory bookings for NDM and long term booking incentives are not suitable as they do not address the fundamental issue that primary capacity bookings are declining due to a changing customer demands. Without acknowledging the changing electricity market and implementing a solution to address the changing needs of market participants, the proposals are not viable and will not address the revenue under recovery issue.

The proposals suggested in CER/13/122 to remove secondary capacity transfers at the exit and restrictions on the latest time of purchase of within day capacity and transfers of secondary capacity at the exit, do not address the factors that have caused BGNs revenue under recovery and as a consequence will not address the revenue shortfall in a sustainable manner. As such, BGN cannot adequately recover their revenues and market participants are detrimentally impacted in an attempt to resolve an issue which will potentially establish fundamentally incorrect market signals, deter future investment and destroy demand. We suggest that the CER carry out a more encompassing review of the status of the gas-electricity market and the contributory factors leading to decreasing primary capacity bookings which have been discussed in detail in earlier parts of this response. This consultation process proposes fundamental changes in the gas market and the proposals are not supported by the necessary analysis or impact assessment. Any changes proposed by the CER should not create market uncertainty or undermine confidence in continuity. This consultation if implemented, would create investor uncertainty for generators and remove tools which enable them to manage risk and cost exposure which is of benefit to the SEM customer through economic electricity prices.

60% of the gas network supplies the energy market. Therefore, such fundamental changes cannot occur in one market i.e. the gas market which will have significant consequential effects in the interlinked market i.e. the electricity market without an assessment of the changes occurring. The revenue under recovery of BGNs must be addressed but it should be addressed in a manner which recognises the changing electricity market both now and into the future to ensure that an appropriate review of the cause of the problem is investigated. It is not feasible for the CER to adopt a silo approach in addressing the financing of the gas transmission system due to the interdependent relationship that exists between the gas and electricity markets.

Suggested next steps to address BGNs remuneration could include further analysis of the PC3 process. Forecasted capacity bookings need to be reviewed in light of the significant over forecasting that has occurred at such an early stage of the price control period. One potential component of a more wide ranging review could be to introduce a process whereby

market participants and BGN have greater communication in advance of forecasting capacity booking levels. For example, power generators are uniquely placed to understand the interdependencies between the gas and electricity market and how the previously used methodology of long term forecastable bookings is no longer relevant or a sufficient tool to provide cost and risk management. If a more accurate forecasting process is in place, this would lead to sufficient revenue recovery and would prevent interim tariff reviews or market distortions caused by the implementation of policies that do not address the actual problem. Factors such as the increasing penetration of renewable energy, the presence of EWIC and less baseload or predictable running for CCGTs need to be reconsidered in the forecasting scenarios to establish a more accurate baseline. The PC3 process used a capacity:commodity ratio of 90:10. One potential solution is to examine the capacity commodity in light of the BGNs accuracy in forecasting flowrates in contrast to expected capacity bookings.

Another potential solution includes reprofiling revenues over the PC3 period to assist in providing adequate remuneration for BGN. This could potentially negate or at least lower the requirement for significant tariff increases for the remainder of the PC3 period. The PC3 process considers a five year period. K factors are used to adjust revenues between actual values and expected values. Thus, any under recovery in one year does not have to be recovered in that year but through k factors that could be smeared over the duration of the PC3 period.

Due to the expected decrease in the premium for Irish government bonds, the WACC figure calculated during the PC3 process could decrease from a current value of 6.3% to a reduced value of 5.2% (as expected by the CER). This decrease is significant and will have a material impact on the revenue requirements of BGN. Our initial review estimates that such a decrease in WACC could decrease revenue recovery by c.€40M over the PC3 period. CER/13/034 states that BGN are forecasting a revenue under recovery of c.€37M. Hence, if the impact of the reduced WACC value is accounted for in Year 1, BGN do not have a revenue shortfall. As this analysis of the WACC value has not been completed, we would suggest that it is not appropriate to consider fundamental structural changes to address a revenue shortfall when the scale of the revenue shortfall could be altered significantly due to a WACC revision.

In addition as already mentioned, there is a heavy premium currently attached to short term exit capacity products which act as a deterrent for purchase. If the Regulator reviewed the pricing to make the products more competitively priced, market users would be encouraged to purchase increasing number of short term strips which would result in additional revenue for BGN.

In summary

- We agree that the gas transmission system needs to be adequately remunerated. We believe the issue can be solved in a manner which addresses both the issue of financing the transmission system but also addresses the needs of the user and the changing electricity market.
- The proposals to remove secondary capacity transfers at the exit or to restrict the latest time of purchase and transfers at the exit do not address the problem causing BGNs revenue under recovery. Implementing these proposals constitute a retrograde step for the Irish gas market and ultimately will not lead to the forecasted revenue recovery.
- A number of potential solutions exist to address BGNs revenue under recovery including the introduction of a process whereby market participants can provide greater feedback to BGN in relation to its capacity forecasting, revenue reprofiling, a CER review of the pricing of short term capacity products, examining the capacity:commodity ratio, analysing the impact of a decreasing WACC value and improving forecasting methodologies.
- We would urge the CER to implement a holding position at this point and to subsequently engage in a more comprehensive review in consultation with industry.

We would be happy to discuss this response in further detail if required.