Access Tariffs and Financing the Gas Transmission System

DOCUMENT TYPE:	**Decision Paper**
REFERENCE:	**CER/13/191**
DATE PUBLISHED:	21 August 2013
CLOSING DATE:	N/A

The Commission for Energy Regulation,
The Exchange,
Belgard Square North,
Tallaght,
Dublin 24.

www.cer.ie

CER – Information Page

Abstract:

The Commission for Energy Regulation (CER) is deciding on matters consulted on in CER/13/122 "Access Tariffs and Financing the Gas Transmission System".

In this decision paper the CER is implementing the two proposals in CER/13/122.

Related Documents:

- Gaslink Code of Operations
- **CER/07/115** - Short-Term Capacity Products Decision Paper
- **CER/10/037** – Review of Transmission Exit Capacity in the Gas Market - Consultation
- **CER/10/089** – Decision on Transmission Exit Capacity Transfers in the Gas Market - Decision
- **CER/12/033 -** Update to Decision on Transmission Exit Capacity Transfers
- **CER/13/034** – Interim Review of BGN Allowed Revenues and Gas Transmission Tariffs for 2012/13 – Consultation
- **CER/13/080** - Interim Review of BGN Allowed Revenues and Gas Transmission Tariffs for 2012/13 – Decision
- **CER/13/122** – Access Tariffs and Financing the Gas Transmission System – Consultation.

Table of Contents

1. Executive Summary

This decision paper follows on from the consultation paper CER/13/122 of 31st May 2013 ('the Consultation') where the CER sought views on certain reforms of the gas transmission financing and charging system, including, and in particular, proposals to

(i) remove secondary capacity transfer at the exit
(ii) remove within day short term capacity products and transfers at the exit – these would not be available after 9.00h on day D-1.

The Consultation Paper also confirmed that the CER decision (CER/10/089) of 17th June 2010 to restrict secondary capacity transfer at the exit would come into effect from 1st October 2013.

The key driver behind these significant proposals is the recent major drop off in primary bookings of capacity by power generators and large Industrial and Commercial (I&C) users. This is due to a number of well documented developments – growing wind energy penetration, the East-West Electricity Interconnector coming on stream, the re-emergence of coal fired generation as well as the difficult economic circumstances. These developments seem very unlikely to be a short term phenomenon. Even with an economic recovery, large users who have a "peaky" consumption profile will continue to be far more drawn to short term and flexible capacity products at the expense of primary bookings than has been the case historically.

This in turn raises serious regulatory policy questions. If we assume that the capital investments in the transmission system – a largely fixed sunk cost – will continue to be underwritten by all users and there is no change in the current tariffing regime, then the shift from primary annual bookings to short term/flexible products by certain large users will inevitably drive up unit tariffs for the remaining users (largely residential and small/medium enterprises – the "non-daily metered" (NDM) users, as well as I&C users with a flat load) who are not in a position to avail of short term or flexible capacity products.

In the Consultation the CER was concerned with whether the prevailing transmission capacity arrangements at the exit were fair and equitable. The CER is of the view that the prevailing arrangements would neither be an efficient nor a fair system for running and financing the gas transmission network, and would, unless changed, lead to significant increases in gas tariffs paid by residential and SME users of gas. To illustrate the scale of the issue, if neither of the reforms under consultation are implemented, then the transmission capacity tariff at the exit will need to increase by *circa* 14% from

October 2013. This would be on top of the 6% mid-year increase in overall network tariffs implemented last April[1].

The gas network has been constructed to meet all gas customers' peak requirements. The gas network system has been used to its fullest capacity, most notably on two occasions in 2010 when 1-in-50 conditions occurred. The 1-in-50 requirement does mean that at most times there is a "surplus" of capacity on the system. The 1-in-50 requirement is more costly than constructing the system to less than a 1-in-50 standard, but it is necessary, for security of supply reasons, to continue to build out the system to meet this standard.

The proposed reforms were justified in the Consultation Paper on the grounds of fairness and efficiency in the allocation of the cost burden of financing the required transmission system to meet customers' peak requirements. Product flexibility is an important aspect of our gas and electricity market designs. But this should not be at any cost. Primary bookings will remain the core network revenue base. The Consultation Paper argued in essence that the key factor in allocating the cost burden between user categories should be the purpose for which the network was built – i.e. to meet each category's peak gas capacity requirement.

There were 18 responses to the Consultation Paper. The dominant – though not unanimous - points emerging included the following:

- The Consultation Paper was too narrow in scope, should have been better signalled and supported by detailed quantitative analysis
- The gas network should continue to be underwritten but CER should rely for the moment on mitigation measures (e.g. reducing the WACC, re-profiling revenues within PC3 and/or changing the 90:10 capacity: commodity split) and engage with the industry on a major review of our gas and electricity regulatory regimes and the relationship between them.
- Any reforms should take account of the different connection charging policies applied to NDM and to larger customers
- The proposed reforms could actually compound the problem of demand reduction by forcing large users to switch fuel or exit the market.
- Gas fired generators are expected to become more flexible within the SEM, yet they are being offered reduced flexibility in booking capacity on the gas side.

[1] This potential rise allows for a reduced WACC for BGN from 6.39% to 5.2%

- Some argued that short term capacity products should be priced more favourably to the get the optimal annual/short term tariff balance; others that they are not priced to reflect the flexibility required at present.
- The two reform proposals may be in contravention of EU law.

The CER addresses all of these points, and others in **Section 4** of the Decision Paper. The legal considerations are addressed in **Section 5**. The CER has also carried out a detailed impact analysis, the results of which are at **Appendix A.**

The CER appreciates that the issues being addressed are complex and raise difficult challenges for gas fired power generators in particular. The issues are not unique to Ireland though they are probably more immediate and challenging here than in some other EU States because of the features of our gas and electricity systems. There is no simple or painless solution as some respondents themselves have acknowledged. The CER must also resolve the issues within its own statutory remit.

The CER has examined all the submissions very carefully. We have held detailed discussions with some respondents. We have concluded, however, that the two reforms proposed in CER/13/122 are justifiable and remain the most acceptable, equitable and efficient means of resolving the issues set out in the Consultation Paper while respecting the legitimate interests of all stakeholders and the requirements of the applicable EU law.

Accordingly, these two proposals will be implemented as soon as is practicable in the forthcoming 2013/14 gas year.

2. Introduction and Background

2.1 Introduction

This paper deals with structural changes on the exit of the transmission system. There has been a significant drop in exit capacity bookings - the drop in annual exit demand from 11/12 to 12/13 was 13.3%. This decrease in bookings is directly related to the Power and Daily Metered (DM) sectors radically reducing their firm bookings.

The gas network needs to be paid for if consumers, businesses and electricity generators want safe and secure supplies of gas. If the current pattern of capacity bookings continues, then without any remedial action there would be a significant increase in gas networks tariffs. In the Consultation the CER consulted on measures that it considers will ensure that the increases in tariffs driven by the current pattern of gas capacity bookings do not take place.

Another key consideration in carrying out this review was ensuring that the gas network system is remunerated in a fair and equitable way. It is important that those who benefit from having access to the network pay their fair share of the cost of access to that network. It could be argued that the current levels of flexibility push the payment for infrastructure on to those who are either not offered any flexibility or who are not in a position to avail of this degree of flexibility.

The Consultation examined and consulted on two issues in the gas transmission tariffs regime, both of which apply at the exit only:

- the removal of secondary capacity transfers at the exit from the gas transmission system.

- the removal of within day purchases of short term capacity and the removal of within day transfers of capacity at the exit to 9:00 on D-1.

In the Consultation, the CER also outlined alternative proposals which it stated it was not minded to implement. The CER will not be implementing any of the alternative proposals put forward in the Consultation.

Having considered the responses to the Consultation (see section 4), the CER is now making its decision with regard to the matters outlined in the Consultation.

2.2 Background

In February 2010, the CER published a Consultation Paper CER/10/037 “Review of Transmission Exit Capacity Transfers in the Gas Market” in which the current regime for secondary transfers of exit capacity was examined. Among the key issues which the Commission sought to address in that review was whether the rationale remained for continuing to allow such secondary transfers at the exit. The CER also questioned whether the use of such secondary transfers at the exit was efficient and equitable across the major categories of gas customers.

In June 2010 CER published a decision paper (CER/10/089) “Decision of Transmission Exit Capacity Transfers in the Gas Market” which announced a stepped increase in the price of secondary capacity at the exit. The CER also decided that secondary capacity transfers at the exit would only be permitted within the same customer sector with effect 1st Oct 2012.[2] As part of this decision the CER stated *“it will continue to monitor closely trends in exit capacity bookings, as well as their potential impact, following this decision”*.

In March 2012, the CER produced a further Information Paper (CER/12/033) which provided an update to the CER’s decision on secondary capacity transfers (CER/10/089 above) and the future examination of short-term capacity tariffs. In this Information Paper, the CER decided to defer the implementation of certain changes to the secondary capacity regime until October 2013.

The November 2012 PC3 decision[3] proceeded, *inter alia*, on the basis that secondary capacity transfers would be restricted from 1st Oct 2013.

In January 2013, BGN made a formal submission to the CER requesting a mid-year tariff adjustment along with proposals which sought to redress a significant revenue under recovery which was transpiring for 2012/13 due to a fall-off in capacity bookings. In the February 2013 decision CER 13/034 “Interim Review on BGN Allowed Revenues and Gas Transmission Tariffs for

---

2 CER/12/033 “the CER has decided to defer its implementation for 12 months, i.e. to October 2013.”

3 http://www.cer.ie/en/gas-transmission-network-decision-documents.aspx?article=7c6755c1-140a-433b-b209-468b9e7f0ac1

2012/13" the CER considered the recent drop off in bookings and consequent erosion in transmission tariff revenues. The February 2013 decision, CER/13/080 "Interim Review on BGN Allowed Revenues and Gas Transmission Tariffs for 2012/13 outlined an effective increase of 10.2% in gas network tariffs. This was implemented as an interim measure to raise tariffs in order to allow BGN recoup some of its expected under recovery while at the same time trying to mitigate and potentially negate future significant tariff rises.

BGN outlined several factors which it considered contributed to the drop-off in capacity bookings:

- Secondary capacity availability,
- Reduction in price for short term capacity during summer starting in 2013,
- Wind displacing gas off the merit order in the SEM,
- East West Electrical Interconnector (EWIC),
- Coal being in merit more than gas.

The CER considered a number of means by which the under recovery could be addressed, such as;

- Raise network tariffs;
- Structural changes on the demand side;
- Re-profile revenues.

The Consultation examined structural changes on the demand side; namely

- the potential removal of secondary capacity **transfers** at the exit, and/or;
- the removal of within day purchases/transfers of short term (including within day) capacity at the exit to 9:00 at D-1.

Secondary capacity ***trading*** at the same exit point will be allowed to continue.

The CER defined the following terms in the Consultation and will use these for the current decision paper also[4]:

Capacity Transfer - An Exit Capacity Transfer is where a shipper transfers Primary exit capacity from one geographic location to another geographic location.

[4] More detailed definitions of these concepts, drawing from the Gaslink Code of Operations are available in Appendix B.

Capacity Trading - Capacity Trading refers to the trading of capacity (typically between shippers) at a single geographic location.

3. The Existing Regime

The facility to transfer transmission exit capacity was implemented in 1998 (before CER came into being in 1999 and was given gas regulatory functions in 2002) as part of the first transmission code of operations and there have been significant changes in the sector since then. At that time there were only ten or so third party access sites in the market and only annual primary capacity was available. Some of the customers had loads that peaked outside of the winter such as the sugar processing plants and the facility to transfer exit capacity was considered appropriate for those customers' specific needs. Since then a suite of regulated short term Monthly and Daily capacity products were implemented in 2007[5] which gave significant flexibility to the market.

The existence of secondary capacity impacts on areas of the Connections Policy. Under the Connections Policy, appraisals for new connections and new towns assume that primary annual capacity will be booked by all new customers and will not be transferred away from the site. However in some cases the new sites may not be booking primary annual capacity and in other cases the capacity may be transferred on. This can have an impact on the viability of new connections and can create a burden on other system users. It was noted in the Consultation that options to deal with this issue were to change the Connections Policy or change the policy on secondary capacity transfers at the exit.

Currently the transmission system is built to meet the 1 in 50 peak day requirements. The gas network system has been used to its fullest capacity, most notably on two occasions in 2010 when the 1 in 50 conditions occurred. The 1 in 50 requirement does mean, however, that at most times there is a "surplus" of capacity on the system. The 1 in 50 requirement is more costly than constructing the system to less than a 1 in 50 standard, but it is necessary, for security of supply reasons, to continue to build out the system to meet this standard. For instance, the network needs to be able to support a high usage of gas in a severe weather period where consumers will use large quantities of gas to stay warm and generators will use large quantities to ensure the lights stay on in a situation of high electricity demand.

Table A below illustrates the difference between the 2012/13 expected bookings for certain sectors and the expected bookings at an average year peak and a 1 in 50 year peak. As outlined in the table, it is expected that

[5] Short Term products from the transporter (monthly, daily, within-day1) were made available from 1st October 2007 following CER decision paper CER/07/115.

power generation will book only 69% of its projected peak capacity in 2012/13. Incidentally, this compares to 98% of its actual peak in 2011/12.

Sector	*Unit*	*2012/13* *1-in-50 Year* Forecast Peak	*2012/13* *Average Year* Forecast Peak	*2012/13* *Actual/Forecast* Capacity	*2012/13* *Cap/Ave Peak*	*2012/13* *Cap/1-in -50 Peak*
EXIT CAP						
Total Power	MWh/d	147,918	125,448	86,322	69%	58%
DM I/C	MWh/d	29,559	28,197	10,954	39%	37%
NDM	MWh/d	97,148	68,758	98,651	143%	102%
Shrinkage	MWh/d	5,299	3,263	5,307	163%	100%
ROI Exit	MWh/d	279,922	225,665	201,233	89%	72%

Table A: 12/13 actual bookings V peak and average year expected demand

Transmission exit capacity is booked by shippers in accordance with their requirements and more specifically with Part C of the Code of Operations.

- Non Daily Metered (NDM)[6] customers must book NDM exit capacity as advised by the transporter. Temperature sensitive customers must book capacity for a 1 in 50 year peak day adverse conditions. This means that at most times during the year the NDM sector has spare capacity that it isn't using.
- Daily Metered (DM)[7] customers have discretion on the amount of capacity they book. They are however issued a transporter recommended exit capacity amount which they are not obliged to book.
- Large Daily Metered (LDM)[8] customers book capacity in line with their own requirements subject to the transporter respecting overall system integrity.

At present shippers have the ability to transfer exit capacity as per the Code of Operations. Transfers currently can occur between shippers, between sectors and between individual LDM and DM sites.

For further background information and detailed explanations of how secondary capacity transfers at the exit works please see CER/10/037 "Review of Transmission Exit Capacity Transfers in the Gas Market".

6 NDM customers generally represent all the residential customers and the smaller Industrial & Commercial (I&C) customers.
7 DM customers represent the larger set of I&C customers.
8 LDM customers generally represent the power sector and a small number of the very largest industrial customers.

Given that the power sector is expected to book 70% of its actual peak in 2012/13, as compared to having booked 98% of its actual peak in 2011/12, the CER considered that the existing regime merits review, as commenced in the Consultation. The next section summarises the submissions to the Consultation paper and the CER's responses to those submissions.

4. Responses to the Consultation

This section of the paper provides a summary of the responses to CER/13/122 *Access Tariffs and Financing the Gas Transmission System* ('the Consultation'). Each section contains a summary of submissions relating to that matter followed by the CER's italicised response.

Many respondents, particularly those from the Power Generation sector, were generally not in favour of the CER introducing the two proposals outlined in the Consultation. A number of respondents were concerned that a revenue shortfall on the part of BGN should be spread in a fair and equitable manner across customer categories and welcomed one or both of the proposals by the CER. It was also suggested that any revenue shortfall on behalf of BGN should be recovered from the beneficiaries of the reduced capacity bookings, namely suppliers to the DM and LDM (including power generation) segments of the gas market.

4.1 Scope & Development of Consultation

It was noted by a number of respondents that the signalling, forecasting, and overall process for this review could and should have been better. It was noted that in CER/13/080, the CER committed to undertake 'extensive consultation on tackling the structural issues in the gas market' and it is fair to say a number of respondents did not consider the Consultation represented 'extensive consultation'. The complexity and commercial importance of the issue at hand (financing the gas transmission system in an appropriate manner) was considered to require a substantially greater level of diligence and quantitative explanation.

It was considered that the CER has taken too narrow an outlook in its proposals, focusing almost exclusively on forcing annual exit capacity bookings as a means of stabilising gas network revenue recovery without properly attempting to understand the implications in the overall energy market. A number of respondents suggested that to implement an enduring solution to BGN's remuneration, a more thorough and far-reaching review which addresses the interoperability of the gas and electricity markets is required. Factors such as increasing wind generation, EWIC operation, and merit order of other generation plant are impacting the capacity bookings of power generators. These were not considered to be temporary phenomena.

It was considered that more detailed analysis needs to be undertaken (and published) by the CER before it can prudently proceed with any of the suggested measures. A review, supported perhaps by some additional expert external input could provide analysis, findings and recommendations which could deliver a more transparent, long-term, flexible and robust methodology for fair apportionment of costs. Such a review should also take account of the negative effect which any increase in gas network charges is likely to have on the viability and competitiveness of industries located in Ireland. A more consultative, industry-wide approach encompassing the key participants in gas and electricity needs to be undertaken to understand the issues.

One respondent noted that the CER presented this matter as an exit capacity only problem. It was considered that an equal focus should be placed on addressing any tariff under-recovery issues which may be associated with under recovery from entry bookings, i.e. principally due to sunk Interconnector investments costs.

CER Response: *The CER notes that considerations regarding the appropriateness of the continuation of secondary capacity transfers were first outlined in 2010 in CER/10/037. In CER/12/033 the CER noted that it "continues to see serious shortcomings in the operation of the current secondary market regime". In the difficult, but necessary, consultation and decision papers regarding the interim 2012/13 gas transmission tariff increases in February 2013, the CER noted that it would be consulting on structural changes to address the unprecedented fall off in capacity bookings.*

The CER developed the Consultation in response to the rapidly declining primary gas capacity bookings and focused in that paper on the structural changes at the exit it considered were necessary. The CER considers that the action taken by it in the form of the Consultation and this decision is necessary to rebalance the equity of gas transmission network cost recovery at the exit and avoid further tariff rises at the exit. The CER was not considering entry tariff matters in the Consultation and will not be doing so in this decision.

In the Consultation the CER recognised that the decline in capacity bookings was not likely to be a short term phenomenon. A large element of the drop in capacity bookings was sudden and directly resulted from changes in bookings in the power sector. As a result of this change in bookings from the power sector the residential and I&C sectors were paying a larger (and arguably disproportionate) share of the costs of the gas transmission network. If the CER delayed a response to this matter, this would only serve to prolong the inequitable distribution of the gas transmission network recovery.

The CER recognises that it is important to consider the effects of the proposals in the Consultation across the different gas customer categories, *and be cognisant of changes in the electricity market that are driving changes with respect to booking behaviour in the gas market. Notwithstanding the above, the proposals made in the Consultation would likely have the effect of shifting some of the burden of the costs of the gas transmission network back to the power sector. The CER recognises this may be challenging for the power sector. The alternative is that the residential and I&C sectors shoulder a burden that the CER considers is more appropriately placed on the power sector*

The CER has conducted an impact assessment as part of its considerations for this decision paper. This is outlined in Appendix A.

4.2 Stranding of BGN Assets/Impairment of BGN asset Values

Many respondents acknowledged the need in principle for the recovery of network financing costs. It was acknowledged that the gas system is necessary and its costs should be remunerated.

Notwithstanding the above, a number of respondents suggested that the CER should take a closer look at the value placed on BGN's assets including the gas interconnectors between Ireland and Great Britain. It was felt by some respondents that the assessed value of BGN's assets may be too high and that the value of some assets should be written down over time. For such respondents, the implementation of a network recovery model that puts what they consider to be a realistic value on the assets would be preferable.

It was suggested that in the context of a write down of BGN assets or another such shortfall of revenues for BGN, the Irish State could step in and cover any capital shortfall. It was also suggested that the CER should not continue to allow BGN recover the current level of investment in the transmission network services with the current changing pattern of demand for gas transmission network services. In this context, the CER was called upon to adjudicate between the interests of asset investors and final customers.

Another potential solution suggested was to re-profile revenues over the PC3 period to assist in providing adequate remuneration for BGN. It was suggested that under recoveries in one year could then be recovered through k factors over subsequent years.

CER Response: *The CER approved a fair value for assets in the 2012-2017 PC3*[9] *process, and the relevant revenue processes preceding this. As noted above, for the most part there was agreement among respondents that the assets will be used on the peak days (cold weather, gas fired generation running at full output), therefore the assets should be remunerated.*

Regarding the entry points, the Consultation and this decision are about the transmission system exit, so the entry considerations are not directly relevant in this context.

The CER is not at this stage considering writing down the value of assets which have been reviewed and approved in the PC3 process. The CER acts under its designated powers under the Electricity Regulation Act and under the framework of relevant European legislation. The CER considers that it has adjudicated appropriately under its duties between the interests of asset investors and gas customers in its PC3 decision and previous gas network revenue reviews.

K-factors cannot be used to fix a prolonged drop in demand, in simple terms if capacity bookings remain low for a prolonged period, then such K factors will never recover the missing revenues without significant increases in tariffs. The longer that recovery is delayed the larger the subsequent increase in tariffs (assuming the capacity bookings remain low). This paper and the preceding consultation (CER 13/122) are not relating to under recoveries or k-factors; it is about equity and seeking to create a structure where different parties pay a fair share of the costs they impose on the system (which relate to the size of the connection not how much it is used). It is true that more "equitable" sharing would likely lead to a lower tariff, however, this is an important consequence of the primary objective i.e. equity.

4.3 BGN WACC Reduction

It was also suggested that a reduction in the WACC applicable to BGN from the PC3 process could be applied to the year 2013/14 to immediately address BGN's revenue concerns.

CER Response: *In PC3, the CER reviewed and decided upon an appropriate trigger mechanism for the WACC whereby the allowed cost of capital is reviewed annually and adjusted if there are further significant changes in*

[9] http://www.cer.ie/en/gas-transmission-network-decision-documents.aspx?article=7c6755c1-140a-433b-b209-468b9e7f0ac1

market conditions in Ireland. The CER has published[10] *the change in WACC which has resulted in the WACC being reduced from 6.39% to 5.2%.*

4.4 Connections Policy Considerations

A number of respondents suggested that the Gaslink Connections policy should be considered in the CER's decision of whether to implement proposals one and two in the Consultation.

A number of respondents considered that the up-front investment made by LDM customers (including power generation) for both the shallow and deep connection costs associated with their connection to the gas transmission network are equivalent to the payment made by an oil-fired power station for an oil tank or a coal fired station for a coal bunker. It was outlined that generators make a 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.

It was considered that as LDM customers pay the shallow and deep costs associated with their connection, it is appropriate they are afforded the flexibility to book their own capacity levels as no contribution is required to be made to the Long Run Marginal Cost (LRMC) associated with their connection. Under current connection policy a CCGT would be subject to a deep connection charging policy and so would have to pay for the full cost of all system reinforcements either up front (or over seven years). It was suggested that the upfront payments that such generators make for connection to the network is in fact equivalent to payments made by an oil-fired power station for an oil tank or a coal fired station for a coal bunker.

It was suggested that domestic customers do not contribute towards any deep reinforcement costs and pay a standard connection charge. It was suggested that in any proper assessment of the equity question consideration should be given to the differences in what different customers are contributing in terms of any monies paid to general network development.

The fact that LDMs are subject to a deep connection charging regime but have flexibility in their bookings was considered consistent with the fact that NDMs pay for 1 in 50 year capacity but are not subject to deep reinforcement costs up front. Therefore, as LDMs pay significant costs for their connection and that is was deemed appropriate for them to be able to manage their

[10] See http://www.cer.ie/en/gas-transmission-network-current-consultations.aspx?article=5df59af3-2e89-493f-8244-4af1a0cec775

commercial exposure through the potential reduction of capacity bookings through flexible products. In any proper assessment of the equity question consideration should be given to the differences in what different customers are contributing in terms of any monies paid to general network development.

In summary, it was suggested that the CER needs to take account of the above 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. A number of respondents suggested that different customers benefit to a different extent from the investments made in the network.

CER Response: *The Gaslink connections policy can be found here (Gaslink Connections Policy[11]). In section 2 the policy outlines a number of high level objectives which include encouraging the connection of new customer load where it is efficient. The objective of connecting efficient new customer loads should, in the medium and long term, increase throughput and reduce unit tariffs for all gas customers. It also seeks to ensure that connection charges provide an appropriate signal of the costs of connections to shippers and consumers.*

It is important to note that the connections policy covers new connections to the existing system. All new connections cause some incremental infrastructure to be built. The incremental costs caused by large new connections can generally be attributed to specific connections, even when they are distant to the new connection (so called deep costs). On the other hand the deep incremental costs of a small new connection may be difficult to identify, if they even exist. The exit infrastructure in Ireland can reasonably be described as robust, it was designed to allow for the creation of sufficient capacity out to 2025. In this context, there is generally sufficient deep transmission infrastructure already in existence for most if not all demand connections for the next long number of years. Thus the likelihood of a single house connection or a new town connection (or in fact even a power station) causing incremental deep costs is low.

In fact given the existence of such robust infrastructure, it is appropriate to encourage incremental connections in order to boost throughput and utilisation (and lower average costs), this is what the connections policy attempts to promote.

It is also interesting to note that a large part of the power sector would have connected prior to the implementation of the current policy.

[11] Gaslink Connections Policy http://www.gaslink.ie/index.jsp?p=135&n=150

This consultation considers changes to arrangements that affect the exit transmission tariffs. The responses relating to the connections policy are therefore evaluated in relation to the transmission system.

Respondents noted that where a large connection has paid 100% upfront for the shallow and deep costs that they have imposed over and above the existing system, then all of their capacity charges can be considered to remunerate the development [including maintenance] of the existing system. This is contrasted to the situation with other connections where some of their capacity payments go towards paying down the incremental costs they have imposed on the transmission system. In summary, the issue surrounds how much of the incremental transmission revenues from new connections go towards remunerating the existing transmission system (all of it in the case of new large connections) and how much goes towards remunerating the incremental transmission infrastructure associated with the new connection.

Residential connections

Under the connections policy transmission revenue is NOT considered when setting the standard residential[12] connection charge or when carrying out "economic tests" to examine whether or not "supplemental charges" are required for one off residential connections, housing developments or what are called "mixed developments" (where there is a mix of residential and say, offices and shops in the development). In all these cases all incremental transmission revenue from these connections can be considered to be remunerating the existing transmission infrastructure (similar to the large new connections).

New Towns

A significant number of new connections have been made under the connections policy under the heading of "New Towns". New towns can involve incremental transmission infrastructure as well as incremental distribution infrastructure which are not paid for up front. In evaluating the viability of new towns, both transmission and distribution incremental revenues are considered in the decision. All new towns decisions must be NPV positive[13] when evaluated over 25 years. New towns typically have involved significant expenditure on the distribution side with minimal expenditure on the transmission side; while the new towns involve incremental revenues in both transmission and distribution. All the new towns decisions made under this policy have in fact all had an NPV positive effect on transmission tariffs. In other words, while the incremental transmission costs were not paid for

[12] The term used in the connections policy is "domestic". This paper uses the favoured term "residential".
[13] Considering both transmission and distribution costs and revenues.

upfront by the new towns, the effect of the incremental revenues would be to lower transmission tariffs.

<u>Medium and small I&C (30% upfront)</u>
A final category of connections is considered, called "medium and small I&Cs". These connections pay only 30% of incremental costs upfront with commitments to make payments equal (in NPV terms) to the remaining 70% of incremental costs over a given period. Thus it can be said that some of the incremental revenues from these connections goes towards the incremental costs of these connections, in other words not all of the incremental revenue is going towards the existing system (unlike those who pay 100% upfront). Similar to the effect of adding new towns, for as long as these new connections continue to make payments in line with the annual payments in the appraisals; these new connections result in incrementally lower tariffs than would otherwise arise.

It is important to note that where any party makes an upfront contribution to their connection under the connections policy, the value of the asset paid for does not go onto the RAB.

In summary the connections policy seeks to balance a number of potentially conflicting objectives including encouraging new connections in efficient locations (by sending the 100% or 30% upfront price signals) while not discouraging new connections that might otherwise lead to lower tariffs.

It is clear from the above that the effect of incremental revenues from new connections is taken into account in the connections policy both in terms of tariff revenue received and the overall effect on tariffs. In short the connections policy takes tariffs into consideration. But the question asked in the responses is whether or not payments made under the connections policy itself should be considered when setting tariffs for certain customers? In other words, should tariffs take the connections policy into consideration?

The connections policy is about promoting new connections onto a system that already has a large amount of infrastructure in place, this is economically efficient. Tariffs on the other hand are broadly about charging users for services provided by the infrastructure that is already in place[14]. At the outset, the Commission wishes to state that it is not at all convinced that connections issues should at any stage be considered in tariffing policy. However, the issue has been raised and will be considered in that context.

[14] Though tariffs can have forward looking elements also

In general terms, if the connections policy was to be considered in relation to tariffing, it would need to be established under what connections policy each customer or class of customer connected. There would be considerable logistical issues with any such arrangements. Any proposal to apply differing tariffs (or tariff structures) to customers based on what they paid for their connection could be said to lack in transparency some and would likely lead to a plethora of differing tariffs[15] *for what otherwise would appear to be the same service. If customers who had "paid off" their connections then paid a (presumably) lower tariff, this would lead to a higher tariff being applied to new connections. Such higher tariffs for new connections could run counter to the policy of promoting new connections in an efficient manner in order to lower overall tariffs for existing customers (by adding incremental net revenues from new customers).*

Consider the following example:

- *There is an existing RAB of €100m.*
- *Customer A pays for its large new connection upfront at a cost of, say, €5m.*
- *Customer B pays 30% upfront and 700k is put onto the RAB*

None of the respondents advanced any reasoning as to why both parties should not pay the same tariff for access to the pre-existing RAB (€100m).The logic of the arguments put forward seems to be that customer B should pay a higher tariff owing to the fact that it has caused €700k to be put onto the RAB. If this was the case it would counteract the effect of being asked to pay only 30% upfront. If the payment of only 30% upfront is designed to be a signal to attract new connections then it would not be logical to dilute (or possibly remove) this signal by charging customer B a higher tariff.

It is worth noting that once customer B pays more revenue to the system than the addition of their €700k to the RAB causes, then customer A is better off for having them on the system. Limiting the 30% upfront policy to smaller connections means that that this net benefit can always be expected to arise.

One respondent suggested that the differences in the connections policy should be considered in regard to the "equity issue". In the respondents view, the fact that 100% of the transmission capacity revenue that power generation (and other large I&Cs) pay goes towards remuneration of the existing system should be taken into account in determining what might be considered an equitable split of the total cost of the transmission exit costs that each sector

[15] E.g. differing tariffs for those who connected under old policies; those who had paid off their connection either upfront or over 7, 20 or 25 years; those within new towns etc.)

should pay. As noted above, any such consideration could then apply to most or all of those who connected under previous connections policies and would also apply to most residential connections [16]

Presumably this suggestion would involve those customers paying a smaller percentage of the overall costs than might otherwise be suggested by peak day capacities. This would, in the main, leave just those elements of the I&C sector who benefited from the current connections policy, to pay the increased share of the costs. Noting above the beneficial impact on tariffs of adding those customers and the potential risk of any such reallocation causing some of these customers to leave the gas system, any such policy would carry high risk.

4.5 BGN Forecasts Accuracy

A desire for more accurate forecasts from BGN was expressed in a number of responses to the Consultation. It was noted that more accurate forecasts would result in more accurate tariffs and remove the need for mid-year tariff increases such as those seen in February 2013. Respondents noted that in the context of numerous factors (primarily electricity market factors) affecting gas-fired generators, they considered that it is difficult to see how BGN did not foresee the significant drop in primary gas capacity bookings which occured as a result of these. A respondent noted that this may also indicate the lack of an effective incentive regime on BGN with respect to forecasting. It was noted that the macro-economic environment reduction in demand and the upward effect on tariffs in this context should also be taken into consideration.

It was also suggested by some respondents that a feedback process between BGN and the LDM sector could be set up to provide for more accurate forecasting. In this context it was considered appropriate that BGN have greater communication with shippers in advance of forecasting capacity booking levels. It was noted 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.

[16] Except perhaps those residential customers within new towns.

As certain gas customers' demand moves towards increasingly flexible products, it was argued that basing transmission demand forecasts and transmission tariffs on less flexible products will not take account of potential demand destruction that will likely occur. A number of respondents made calls for the current level of flexible products to remain in place and forecasting to take account of new/existing flexible products in that context.

CER Response: *It is true that forecasting can take into account expected revenue from short term capacity sales. However while greater forecasting accuracy may be a tool in assisting with the recovery of network revenues within a defined period, it does not address the serious structural and equity issue with gas transmission network cost recovery that the CER must address in this paper.*

The CER acknowledges that the mid-year tariff increase in February was a difficult, if necessary, measure to implement to allow BGN recoup some of its expected under recovery while at the same time trying to mitigate and potentially avoid future significant tariff rises. CER/13/080 was about addressing a revenue shortfall issue, this decision paper is by contrast primarily concerned with addressing the equity of transmission tariff cost recovery.

The CER agrees that a number of factors such as increasing penetration of intermittent renewable generation, and increased usage of the EWIC are primarily making forecasting gas usage in the power sector increasingly difficult to predict with accuracy. The CER acknowledges that the trend in usage for gas fired power plant is changing for some plant from the traditional baseload to more mid-merit and peak generation operation and that forecasts for usage of, and bookings for, the transmission network should take account of this. The CER also notes that there is currently a significant level of interaction between BGN and gas shippers with respect to forecasting of capacity bookings and that this will need to continue in the context of the changing trends in usage for gas fired power plant. However, this does not change the current need to rebalance the manner in which transmission exit revenues are recovered from customer categories.

4.6 Capacity/Commodity Spilt for Transmission Network Cost Recovery

A number of respondents consider that the CER should examine the current 90/10 capacity commodity split and that modifying the current regime could result in a more appropriate and proportionate approach to address the revenue requirements of the gas network. It was noted that the 2012 Gas

Capacity Statement[3] is forecasting annual power sector gas demand to rise by 33% between the period 2011/12 to 2020/21 which suggests increased gas commodity throughput in the coming years. This suggests a recalibration of the capacity/commodity split towards an increased commodity component would be a successful long term measure. Through more accurate BGN forecasting, it was noted that a greater weighting on commodity would stabilise revenues and tariffs. It was suggested changing the split to 75/25 or to 60/40.

The 90/10 capacity commodity split was questioned in the context of the power generators given that they pay a larger proportion of the upfront costs of their network connection than the retail sector. It was outlined that as gas power sector demand is expected to rise in the coming years, it was considered that a revised capacity commodity spilt, for the power sector at least, would more appropriately allocate the long run costs of the system proportionately to the different sectors.

A respondent noted that stabilising the transmission revenues while retaining the level of flexibility, which BGN is able to operationally facilitate, will better allow the gas market to respond to and accommodate changes in the electricity market. Given the changing dynamics of the electricity system towards more renewable and gas generation, this should ultimately increase gas demand in the long term, thereby decreasing long run fixed costs for all customers of the system.

CER Response: *The CER considers that the 90/10 capacity commodity split is more cost reflective than other choices of split as the actual cost of a pipeline is generally accepted to be closer to a 90/10 fixed/variable split than say 75/25 or 60/40. The CER accepts that a change to the commodity may help to ensure that revenue returns on new connections are not as dependent on capacity bookings.*

Of primary importance here, however, is that moving network cost recovery away from capacity charges towards increasing commodity charges moves network recovery costs away from peaky customers. Those customers who are not peaky would end up paying more overall gas transmission charges because peaky customers would not have to pay the same level of capacity charges as they would under a higher capacity proportion in the split. The costs imposed on the gas transmission system by flat and peaky customers are fundamentally dictated in both instances by the customers' peaks, not their average usage. Therefore, a high capacity element, as is currently the case, is deemed to be the appropriate split for recovery of gas transmission costs.

The latest Draft ACER Framework Guidelines (revised chapter) on rules regarding harmonised transmission tariff structures for gas[17] *state (section 3.3.1) "The collection of the revenues shall be based primarily on capacity charges."*

In section 3.3.2, the Guidelines also state:

"Subject to approval or determination by the NRA a specific charge related to the volume actually flowed by shippers could be established to cover costs that are mainly driven by the volume actually flowed by shippers (such as compressor fuel cost). Where applied, this charge shall be levied equally for all entry points and equally for all exit points, based on the actual flows of the individual shippers" [End quote].

A separate charge is paid by shippers to cover the costs of gas compression in line with 3.3.2 above. Gas compression costs are the primary operational/volumetric cost driven by the volume of gas actually flowed by shippers. This charge (the shrinkage charge) is in addition to the 10% commodity weighting recovered from shippers as part of the required revenues for the transmission network. In this context, an increase in the commodity charge split in the network tariffs would not be appropriate.

Consequently for the reasons outlined above, the CER does not intend to modify the current capacity-commodity split. The CER will be considering the implications of developments in the ACER Framework Guidleines in this context when they are finalised.

4.7 Tariff Levels for Short Term Capacity Products

There were differing views on this matter, including how more flexible short term products could be priced. Some respondents considered that the price of short term capacity products were too favourable whilst others considered that short term products were priced excessively and make the products less attractive to gas market participants. In this context, a respondent noted that the current problems regarding transmission network recovery costs cannot be attributed to the fact that flexible products are available, it must be due to the fact that tariffs are charged for different services which do not equitably apportion the burden. It was noted that if the power sector is booking different types of capacity, it is not only open to the CER to tariff such capacity bookings differently to ensure that the burden is spread in an equitable and

[17] http://www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2013_G_03.aspx

non-discriminatory way, but the CER is required to do so by legislation. It was noted that the CER is outdated in its belief that the gas system can only be properly remunerated through annual products.

As an example, it was noted that 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 was suggested that the prices of these products are 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, i.e. if short term products were cheaper, then shippers might buy short term capacity from the TSO rather than buy secondary capacity from others.

One respondent noted that it is most likely that the power sector peak will coincide with the system peak (i.e. in cold weather when there is no wind). If a customer requires capacity on the day of a 1 in 50 year peak then the appropriate price for capacity on that day is equal to the cost for booking an annual strip of capacity every year there is not a 1 in 50 year peak, i.e. the pipeline cost must be remunerated for all the other days, not just the day it is used.

Another respondent requested the CER to introduce short term capacity products at prices lower than the current rates that would only be available to retailer suppliers. This is to recognise that retail suppliers have little chance of ever mitigating exit capacity breach penalties. This would also have the added benefit of reducing any penalty charges.

CER Response: *Determining the optimal price relationship between short and long-term capacity products is a central element of network tariff design which has been the subject of much debate at EU level in recent years. The CER does not consider that the prices of monthly and daily capacity products are excessive and notes that there has been extensive consultation on this matter, the most recent of which was in 2012*[18]*. Indeed it is instructive to note the different views of respondents on this matter.*

Flexible tariffs which equitably apportion the burden and, in that context, price flexibility appropriately are an attractive concept in theory. In reality, it would be very difficult if not impossible to achieve consensus on what was the "right price" for flexibility given the differing strong views put forth by respondents on

[18] http://www.cer.ie/en/gas-transmission-network-decision-documents.aspx?article=886b03ec-a4b7-418d-a3bb-71771fc89997

this matter (i.e. short term is too cheap Vs short term is too expensive). The CER considers that the implementation of the two proposals in the Consultation still provide for a level of flexibility in booking capacity, but will serve to increase primary bookings of capacity and also incentivise the booking of annual capacity.

If flexible within day products were to remain, and, as some respondents suggest, the price for such products is reduced, it is difficult to see how such products would adequately contribute to recover the costs of the network. Cheaper short term products may favour increased usage but need to strike a balance by ensuring that the necessary network costs are recovered equitably from customers. On the other hand increasing the cost of short term capacity might place an unreasonable burden on parties who use the system and indeed might reduce utilisation of the system. The CER does not agree that modifying the price structure as suggested provides an appropriate solution in addressing the issues considered in this consultation.

<u>For example</u>: Considering the case where secondary capacity is removed, a gas generator which expects to run ten times a year may decide not to purchase an annual strip of capacity. The generator will more likely purchase short term within day capacity at current prices on the ten occasions with perfect foresight (or more accurately hindsight as the purchase can be made close to the end of the day); as it is more economic to do so than purchase the annual capacity.

If within day capacity (as it is currently priced) is removed, the generator may choose to pay for annual gas capacity or to bid on an alternative fuel as it may be more economic to do so than run on gas. If a flexible short term within day product was priced correctly (i.e. to recover the revenues required for the network being available for that generator), that product would recover, over ten purchases, the same as an annual strip of capacity.

It is not clear how much another site that expects to run for five or twenty days would therefore be charged unless the charges became site-specific or were averaged for charging all sites of a similar profile.

The difficulty in creating an appropriate product in this regard lies in the nature of ex ante forecasting. The CER acknowledges that reduced flexibility in this context is an issue for the power sector in particular. The creation of a product that provides the required level of flexibility, is correctly priced, which recovers sufficient network revenues might not be achievable on an ex ante basis. It is important in this context not to conflate the concept of having a flexible gas system (which is capable of meeting the changing needs of its power *generation customers) with the concept of flexibility in booking and paying for capacity.*

The CER acknowledges that by removing both secondary capacity transfers and within day primary short term products in tandem those customers who would have availed of short term primary gas products are more likely to book annual capacity or, on the other hand, may choose not to book any capacity at all. There is therefore some level of trade-off here between annual and shorter term primary gas capacity bookings. However, the CER considers that the result of reducing flexibility in booking capacity as proposed in the Consultation is likely to result in a more equitable distribution of primary gas capacity bookings, which would in turn result in preventing very significant tariff rises for all customers. The CER considers that the rationale for introducing both measures together is correct.

In another response it was noted that removing the flexibility in gas market products will not address the interaction between the contributory factors resulting in decreased exit capacity bookings and so will not address the problem causing BGN's revenue shortfall. It was noted that an operationally flexible system with an inflexible tariff system will only serve the needs of those customer whose requirements match the preferred product offered. It was also noted that the signals for an efficient network would be blunted by effectively imposing cost allocation on customers which does not reflect the actual usage of the gas transmission system by those customers. In this context, it was suggested that BGN propose new and innovative products that reflect the changing needs of electricity generators.

<u>CER Response:</u> *The CER notes that the gas system remains operationally flexible. In the context of the current decline in primary capacity bookings, the CER considers that it is appropriate to remove an amount of the current flexibility in booking capacity that is available to gas shippers through implementing proposal 1 and 2 in the Consultation. An operationally flexible system is not the same as flexibility in booking and paying for capacity.*

4.8 ACER Framework Guidelines – Short Term Tariffs

Another respondent quoted that the Draft ACER Framework Guidelines on rules regarding harmonised transmission tariff structure for gas state "The Network Code on Tariffs shall set out that, in determining the reserve prices for daily and within-day firm standard capacity products, NRAs may also apply multipliers and that these multipliers may be higher than one, but not higher than 1.5 on average over the gas year at the respective entry or exit point in the absence of congestion”. The respondent noted that without substantial changes to the Draft Framework Guidelines, it is difficult to imagine how the CER’s vision for tariffs will meet the framework guidelines, or be compliant with the finalised network code on harmonised transmission tariff structures.

<u>CER Response:</u> *The CER notes that this part of the Draft ACER Framework Guidelines (section 5 ‘Reserve Price’) on rules regarding harmonised transmission tariff structure for gas refers to entry and exit at interconnection points between systems. The CER does not therefore believe the proposals in the Consultation and decisions in this paper are in contravention of the Draft ACER Framework Guidelines on rules regarding harmonised transmission tariff structure for gas.*

4.9 Vertical Integration/Market Power Considerations

It was noted that shippers with a diversified portfolio may be able to benefit from secondary capacity transfers more effectively than shippers who would have to trade with other organisations to optimise their capacity holdings. I was argued that the CER must recognise that any implementation of the decision to restrict secondary transfers in CER/10/089 without a simultaneous implementation of the two proposals in the Consultation benefits the vertically integrated players, which is tantamount to the CER discriminating against non-vertically integrated players.

A respondent noted that the fact that re-allocations of gas exit capacity will in practice be still be available to a small number (perhaps only one) participant, i.e. those with multiple gas generator units on the same site, could amount to significant discrimination, particularly considering the other market mechanisms adopted to counter market dominance.

<u>CER Response:</u> *The CER intends to direct the implementation of the two proposals in the Consultation paper. The CER will direct that both proposals be implemented as soon as practicable.*

With the implementation of both proposals in the Consultation, the CER considers that the effect of increasing capacity bookings on the system results in less discrimination between customer categories and a more equitable redistribution of payment of the revenues required to fund the gas transmission system itself. As outlined in the Consultation, the CER considers that continuing to ensure there is generally “surplus” capacity at the exit, while *at the same time allowing surplus exit capacity to be transferred, reduces bookings on the exit and leads to higher tariffs and is economically inefficient.*

On the other hand the CER considers that continuing to allow capacity trading at the same exit point is efficient. Where two or more users are located at the same point (entry or exit) then secondary capacity trading at that point will help to ensure that the capacity which is booked at that point can be used to its maximum.

4.10 Storage

It was noted that if shippers cannot purchase exit capacity within day at a reasonable price then it will be impossible to capitalise on low summer gas prices for injection into storage. The respondent noted that it would seem unreasonable to remove this flexibility if this were to threaten security of supply in the coming winter.

CER Response: *These proposals do not affect the exit of capacity from the BGN system into storage. There is one storage facility currently operating in Ireland, namely the Kinsale Energy facility at Inch. In common with other jurisdictions, specific arrangements have been put in place with regard to exit into storage. In order to exit gas from the BGN system into the storage facility it is necessary to be listed on the exit capacity register at Inch. This exit is offered on an interruptible basis and capacity charges are not levied for this exit. Thus issues regarding purchase of or transfer of exit capacity into storage do not arise.*

4.11 Consistency with CER/10/089 – the Equity Issue

A number of respondents noted that in 2010[19] the CER arrived at the opposite conclusion to that suggested in the current consultation. It was noted that the CER previously believed (in CER/10/089) that power generators were cross subsidising the NDM market and that this is in direct contrast to the position outlined in the Consultation. 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 BG Energy is removed. A respondent noted that they cannot see how ‘equity’ can be referenced as the key driver for an about-turn in the Commission’s view on secondary capacity transfers without any analysis of booking behaviour post

---

[19] CER/10/089 *Decision on Transmission Exit Capacity Transfers in the Gas Market* *http://www.cer.ie/en/gas-transmission-network-decision-documents.aspx?article=14e5debb-5380-410b-9058-bd4d3f7a79de*

Code Modification 046 “Secondary Capacity Transfers”[20], a detailed examination of the charging regime for short term products and an examination of the existing Connections Policy. A number of parties highlighted that the purpose of Cod Modification A027[21] “Extension of Short Term Daily Capacity Service to include Within-Day Capacity Bookings” was to facilitate interoperability of the Gas market with SEM arrangements and that the current paper is now seeking to reverse this.

In CER/10/089 the CER stated that the sectoral restriction on secondary capacity transfers 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”. Some respondents considered that that the transfer of secondary exit capacity was efficient. BGN noted that power stations and DM IC customers are not booking anything like their 1-in-50 load and noted that they are not even booking the capacity equivalent to their average load.

A respondent noted that the end customer is charged the full gas transportation charge (with perhaps a very small discount), while the shipper trades the allocation between sites. This results in the gas network receiving lower revenues while the end customer gets charged the full rate. The respondent considered that the only people benefiting from this arrangement were the shippers themselves.

<u>CER Response:</u>

The key principle underlying the decision in 10/089 is the same principle underlying the proposals in the consultation.

The NDM sector is “peaky”, that is the NDM sector only uses its full capacity on rare occasions. This peaky nature imposes costs on the system as the system is sized to meet the 1 in 50 peak on the NDM sector. In CER 10/089 CER took the view that the NDM sector was avoiding some of the cost of this peaky nature by selling its “spare” capacity as secondary capacity. At the time the I&C sector and the power sector could have broadly been described as base load rather than peaky, that is, these customers regularly used close their full capacity. Thus by selling secondary capacity and thus avoiding the

---

[20] Code Modification A046 “Secondary Capacity Transfers”. This Code Modification meant that from October 2012 Exit Capacity transfers will be only permitted within the same category of capacity and the transfer of NDM Exit Capacity will no longer be permitted . http://www.gaslink.ie/files/Copy%20of%20library/20120206035553_CODE%20MODIFICATION%20PROPOSAL%20A04.pdf

[21] Code Modification A027 “Extension of Short Term Daily Capacity Service to include Within-Day Capacity Bookings”

true cost of their peaky nature, the NDM sector was pushing (at least some of) the true cost of this peaky nature onto the power and I&C sector.

In the intervening period, the power sector has become much more peaky in nature. The power sector is now using the availability of secondary capacity and within day primary capacity sales to avoid making payments to the TSO for primary capacity. In doing so the power sector is avoiding the true cost of its peaky nature and is pushing (at least some of) the cost of this peaky nature onto others. Given the decision to restrict secondary capacity sales in CER 10/089, from 2013/14 (absent any changes) the power sector would push these costs onto the I&C and NDM sectors.[22]

Where the CER has changed its position since CER 10/089, is that it now proposes to remove secondary capacity transfers rather than just restrict them. In CER 10/089 the CER said it would keep the situation regarding secondary capacity transfers under review. The CER has done so and as a result of this monitoring of the evolution of such transfers since 2010 and their effect of the market, the CER has concluded that it is appropriate to fully remove this facility at the exit.

4.12 General Interactions with Electricity

Respondents noted that factors such as increasing wind generation, lower CO_2 prices, EWIC operation, and merit order of other generation plant are all impacting the capacity bookings of power generators. A respondent considered that the removal of secondary transfers and/or restriction of the latest time of purchases would destroy the alignment and interoperability that currently exists between the SEM market and the gas market. It was considered that the gas-fired power sector was being asked to underwrite the financial consequences of more renewable electricity on the system which competes with gas. The efficient interaction between the gas and electricity markets, through the flexibility provided by secondary transfers, was noted as being vital in an evolving SEM landscape. It was noted that the introduction of these proposals is essentially asking power stations to pay an elevated tariff for a reduced level of service. A respondent noted their concern that changes in the activities of the electricity sector could place a disproportionate burden on the other users of the gas infrastructure.

In effect, it was considered by some respondents that SEM gas generators are now being asked to pay an increased capacity tariff in part due to the

[22] Absent the decision to restrict secondary capacity transfers at the exit, i.e. if 10/089 had not been proceeded with, both the power sector and the NDM sector would push some of the costs of their peaky natures onto the I&C sector and tariffs would rise further than in the base case outlined in the Impact Analysis.

presence of an electrical interconnector that reduces their running and ability to earn revenues. It was suggested 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.

For the power generation sector in particular, it was noted that the increased use of short-term capacity products and services is merely a symptom of, and a perfectly rational response to, the problems that gas-fired generators are confronting. Where mention has been made to symptom/cause type effects, it is plausible to argue that the availability of within day capacity and secondary market transfers are merely a symptom of the changing demand for gas and the cause of the current shortfall issue is the CER and BGN's insistence on ignoring this long term trend and mandating that BGN revenue be recovered predominantly through annual products. The respondent noted that flexibility cannot be regarded as an issue in any enduring solution, rather it should form the basis of such a solution.

It was also suggested that 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. It was considered that 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. A respondent also considered the consultation to be in direct contradiction to the DS3 work on-going to incentivise flexibility in generation to allow the electricity system meet its changing requirements. A respondent note that abolishing flexibility for the convenience of BGN was indefensible.

CER Response:

The challenges posed by the interactions between the gas and electricity systems are not unique to Ireland, though they are probably more immediate and challenging here than in some other EU States because of the features of our gas and electricity systems. There is no simple or painless solution as some respondents themselves have acknowledged. The 40% renewable electricity target for 2020 raises significant operational challenges for many generators in the SEM, which will likely result in indirect costs that may need to be remunerated in the electricity market.

The CER acknowledges that, as outlined by respondents, there are a number of factors which are affecting the capacity bookings on the gas transmission system. The CER acknowledges that at present from a gas-fired electricity generator's perspective it is considered that there is significant alignment of the gas and electricity markets in that short term gas products and secondary *gas transfers provide a way for such electricity generators to manage an element of their exposure to lower load factors[23]. The use of such products and transfers is economically rational for an electricity generator but introduces inequity with regard to how the revenues for the gas transmission system are recovered from gas customers.*

The CER acknowledges the concern expressed by some respondents that the proposals in the Consultation (if implemented) could be considered as asking gas-fired power sector asked to underwrite the financial consequences of more renewable electricity on the system which competes with gas. The CER does not dispute that there are drivers of this requirement for change coming from the electricity market. Whilst there no doubt are challenges for electricity generators associated with significant changes in the electricity market, these electricity challenges are not necessarily something that can or should be resolved, partly or completely, in the gas market. It is appropriate that gas customers pay the level of costs appropriate to the network capacity that is made available to them.

The CER considers urgent action is necessary to rebalance the equity of gas transmission network cost recovery at the exit and avoid further tariff rises at the exit. The CER considers the measures proposed in the Consultation and outlined in this decision paper are necessary regardless of where the main drivers of change have come from.

Keeping the current level of flexibility provided at the exit moves costs to gas customers who cannot avail of that flexibility. As noted above, some of the power generation respondents suggested that these proposals were in effect asking power generation to underwrite the financial consequences of more renewable electricity on the system. Following this logic, by not making any changes to the current arrangements, it would instead be this subset of gas customers (broadly the NDM and I&C customers) who would effectively be asked to underwrite these consequences. The electricity system needs the gas system to be available. If the electricity system, essentially meaning gas-fired electricity generators, do not pay a fair share of the costs of the gas system, then the other 600k gas customers will pay for this rather than the electricity sector with 2.1m customers.

Under the previously prevailing regime it could be said that the power sector is adapting rapidly to the current regime. While this is acceptable and makes sense for gas generators, this is pushing payments onto other gas customers

---

[23] In addition to this financial alignment of products noted by the generators there is significant physical alignment of the two systems. The gas system is capable of providing operational flexibility that the gas generators need, such as going from no load to full load within the day. The provision of such physical flexibility is costly.

such as DMs and NDMs. In effect, the gas system (and in larger part the NDM and I&C sectors) are paying the price of maintaining operational flexibility for the electricity system. The purpose of Code Modification A027 was to ensure interoperability between the SEM and gas markets. Given the dramatic fall in capacity bookings the CER considers that it must take the measures in this decision to restore equity, along with the other significant measures it is taking in parallel (BGN PC3 WACC reduction and reprofiling of Moffat entry revenues), in order to mitigate the effect on the transmission tariff whilst allowing for sufficient revenues to be recovered by BGN.

The gas system needs to be remunerated for providing operational flexibility and availability. The DS3 System Services workstream in the SEM concerns the system services (or ancillary services) that will be required in 2020 to maintain an electricity system that will provide operational flexibility. Whatever revenue is required in order to provide for this in the electricity market is a matter for the SEM Committee. Considering the CER's duties to both gas and electricity customers, it would seem more equitable for electricity customers to support electricity flexibility.

4.13 Preventing of Demand Drop-Off

A number of respondents were concerned that the CER's proposals could result in a drop off in gas demand as an unintended consequence of its proposals. A respondent noted that removing secondary capacity transfers from the market threatens the viability of marginal plants and could ultimately lead to the closure of select power plants. It was noted that demand destruction could result in a self-perpetuating circle of increasing gas transportation costs, the creation of negative investment signals, falling network utilisation and subsequently increasing gas tariffs.

There was a concern that the CER's two main proposals, if implemented, would result in gas generators being unable to compete in the electricity market due to the absence of flexibility and as such would have to exit both the electricity and gas markets. In particular it was noted that CCGT plant are increasingly being moved to operate as mid-merit and peaking plant in the SEM as a result of increasing wind penetration, low CO_2 prices, EWIC utilisation and competition from alternative fuelled plant.

Reducing flexibility through eliminating secondary transfers may exacerbate the trend in falling primary bookings, as mid merit gas fired generators with low load factors would no longer book annual capacity as they would not be able to recoup a portion of this sunk cost through sales of surplus capacity.

A respondent gave an example of a significant potential upward effect on SMP which they consider may result if relevant gas plant were forced to run on alternative fuels. It was suggested that this would result in OCGT plant running as distillate plant and bidding into the SEM accordingly. It is suggested that this could result in significant additional costs to energy customers through significant rises in SMP for those periods plant were running on the alternative fuel. Another respondent noted that the impact of removing secondary transfers at the exit and the consequential impact on SEM electricity prices is not considered in the Consultation but must surely form part of the greater debate.

One respondent states that if flexibility (secondary and/or within day) were removed gas fired generators would not purchase annual gas capacity as there would be no economic rationale for doing so. A respondent noted they would also not purchase short term capacity as there would be no way of forecasting gas capacity requirements.

Another respondent suggested that the 1-in-50 peak day is less applicable to Power Generation or any DM/LDM customers with the capacity to fuel switch.

<u>CER Response:</u> *The CER is aware of the potential implications of its two proposals for some gas fired generation and notes that, following significant consideration and analysis, it must make a decision with respect to the implementation of the two proposals in the Consultation and their likely impact on bookings. The availability of flexible gas products facilitates power generation plant in particular to manage an exposure to a requirement to be flexible in the SEM. The ultimate cost of that flexibility is effectively passed through higher gas tariffs on to gas customers who cannot optimise.*

Access to the gas transmission system is provided for gas customers who are connected to it. First and foremost, where gas customers wish to use the gas transmission system, capacity bookings that contribute to the fixed costs of the available system must be made. The CER considers that the current level of flexibility, provided through the current products, does not provide for the appropriate revenue from capacity bookings to be made from the power generation sector. The CER acknowledges that it is possible that the implementation of the two proposals could result in some gas-fired generation running on alternative fuels, but considers that this potential effect should be exceeded by the increased level of primary capacity bookings on the transmission system exit that should result.

To the extent that some gas fired power stations are not currently making many gas capacity bookings (annual or short-term), the revenue they *contribute to the gas transmission system is not significant. In addition, to the extent those generators may not actually use the gas transmission system much (i.e. they run very little), the commodity revenues that would be lost would be very low[24].*

If such generators wish to continue to have access to the gas transmission system, the CER considers it appropriate that they contribute to that system in a manner that ensures other gas transmission customers are not funding the capacity required to supply gas to such generators during peak times. This is in line with the both the Joint Gas Capacity Statement 2012 and the draft Network Development Plan 2013 [25] which outline that power sector demand in Ireland will consistently be over 50% of the peak day demand out to 2021.

Table B below shows the expected ROI peak day demand share of the power sector out to 2021/22. It is calculated from figures in the draft Network Development Plan 2013.

Table B: Expected Power Sector Peak Demand Proportion

Year	*Peak Day Demand*
2010/11	*54%*
2011/12	*55%*
2012/13	*56%*
2013/14	55%
2014/15	54%
2015/16	55%
2016/17	55%
2017/18	55%
2018/19	56%
2019/20	56%
2020/21	57%
2021/22	58%
Forecast Average	55.6%

Given the system is constructed to meet customers' peak requirements i.e. the 1-in-50 standard, the CER considers it appropriate that customers cover the portion of cost of the system required to meet their peak demands.

Regarding the issue of whether or not the 1-in-50 standard is less applicable to a customer with the ability to fuel switch, the gas transmission system is

[24] Given the 90/10 capacity/commodity split, the revenues recovered from such generators in the commodity element would be unlikely to be very large.
[25] http://www.cer.ie/en/gas-security-of-supply.aspx

planned and already constructed to the 1-in-50 standard, which includes expected load from gas fired generators, regardless of whether they have the ability to fuel switch.

4.14 Interaction with BCOP Paper (SEM-13-039) & SEM Prices

The proposal in the recent consultation paper (SEM-13-039) on the treatment of gas capacity costs in SEM bid prices ("BCOP paper") assumes that a liquid secondary within day gas capacity market exists. However, Proposal 2 in CER/13/122 proposes to remove the within day capacity market, runs counter to the proposal in the BCOP paper. Market participants felt that they could be forgiven for thinking that there may be a lack of clarity and forward thinking in the decision making process in this area.

CER Response: *The CER notes that extensive work has been undertaken by the SEM Committee with regard to addressing the matter of how gas transportation costs are to be treated for SEM bidding purposes. SEM-13-039 sets out the SEM Committee's provisional conclusions regarding generators' Cost-Reflectivity Licence Condition and Bidding Code of Practice (BCOP). SEM-13-039 is essentially setting out the guiding principles, through interpretation of Generators' licences and the BCOP, by which gas transportation costs may be included in SEM bids. Put simply, the fact that an SEM document might reference a certain gas capacity product does not mean that that product must be made available.*

Another respondent asked the CER to consider the case of a generator which decides not to purchase any primary gas capacity, and offers to SEM based on distillate price alone. The BCOP paper proposal, combined with this proposal, will oblige such a generator to offer on the basis of wholesale gas purchase costs plus the price of (any) secondary within day gas capacity (par 4.32, BCOP Paper). The BNE reference plant is distillate only, and any change to the market rules which mandated the use of gas would have clear impacts on the BNE price and associated CPM payments.

CER Response: *The CER notes in the first instance that the proposals included in the Consultation do not mandate the use of gas or gas capacity by generators. Considerations regarding the components and determination of CPM payments are a matter for the SEM Committee.*

4.15 Respondents views of Next Steps

A number of respondents believe that a more measured, consultative, industry-wide approach encompassing key participants in the gas and electricity sectors needs to be undertaken to better understand and assess the issues and potential solutions**.** A number of respondents called for a more comprehensive review which would require further consultation and consideration of some or all of the following.

- The general interactions between gas and electricity, and the guidance note provided by the SEM Committee on the treatment of gas transportation costs in bids.
- The capacity/commodity weighting in tariffs.
- Whether the products available and multipliers applied accurately fit the changing demands of DM and LDM customers, in particular the power generation customers who have been singled out in the consultation.
- That the structural changes considered in CER/13/122 should not be considered until the WACC calculation is complete and a clearer status of BGN's funding requirements are known.
- The re-profiling of BGN revenues. This was acknowledged within the interim revenue on allowed revenues and gas transmission tariffs (CER/13/080), but the Consultation paper limited itself to 'structural changes on the demand side'.
- The Connections Policy and whether or not the assumptions for primary annual capacity being booked are accurate for future network development.

It was suggested that the CER implement a holding position at this point and to subsequently engage in a more comprehensive review in consultation with industry. It was suggested 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.

A respondent strongly favoured the establishment of further workshops to allow all stakeholders an opportunity to openly debate in a more considered fashion all the issues that the consultation process to date has not been able to facilitate. These workshops could form part of and / or follow from a separate expert review (as suggested above) and assist in delivering a greater level of consensus on an agreed resolution. A request was made that the CER carry out a full Regulatory Impact Assessment (RIA) regarding any proposed changes before they are implemented.

Respondents noted that in undertaking a comprehensive review of the matters in the consultation, the CER would follow the Department of An Taoiseach Statement on Better Regulation 2013.

CER Response: *The CER has conducted an Impact Assessment with regard to the proposals, which is included in Appendix 1 to this decision.*

The CER acknowledges that the measures outlined in the Consultation are not favoured by some gas market participants. The CER will not, however, be implementing a holding position with regard to the two proposals in the Consultation. The CER considers that there is sufficient merit in implementing the two proposals on an equity basis, which, alongside the other measures (PC3 WACC reduction, the re-profiling of the Moffat entry revenues) the CER is taking, prevent very significant additional tariff increases. If the CER was not to take any action now then the inequity in network costs recovery would continue and exit tariffs would increase.

5. Legislative Basis

This decision is made pursuant to Section 13(3) of the Gas (Interim) (Regulations) Act, 2002 which enables the CER to give directions from time to time to Gaslink in respect of its code of operations.

Compliance with EU Law.

The CER stated in Consultation Paper CER/13/122 that it was satisfied that the proposals to

(i) remove capacity transfers at the exit and
(ii) remove the current ability to buy/transfer gas capacity *within* day

would be compatible with applicable EU law, and in particular with Regulation 715/2009. This was essentially on the grounds that

- Article 16.3 of the Regulation specifically relates to "*procedures which facilitate cross-border exchanges in natural gas*" and therefore, by extension in CER's view, to interconnection points and not to transfers at exit points and

- The TSOs' duty to offer firm and interruptible services are expressly limited in Annex 1 to the Regulation "*down to a minimum period of one day*."

Several respondents have queried or challenged this view.

Among the main arguments advanced by these respondents are the following:

- CER's analysis of the scope of Article 16 of the Regulation is not necessarily correct
- CER ignores Article 22 of the Regulation
- CER should not see itself as legally restricted to meeting the *minimum* requirements of the applicable EU law.
- The "letter and spirit" of the Regulation and of Directive 20009/73/EC and in particular the importance attributed to promoting market liquidity would not support the proposals

The CER is also aware that a letter of complaint on the matter has been sent to the European Commission. The CER is of course happy to engage with the Commission should the Commission wish to follow up on the letter of complaint.

The CER has reflected on the views of these respondents but remains satisfied that the two proposals are compatible with the applicable EU law.

On the issue of the proper interpretation of the Article 16.3 of the Regulation, the CER considers that a straightforward reading of the opening sentence, with its focus expressly on "*procedures which facilitate cross-border exchanges in natural gas*," would support the view that the its provisions apply to interconnection points and not to all exit points on every gas system in the Union. Otherwise it would beg the question of what would have been the purpose of inserting the phrase "*which facilitate cross border exchanges….."?*

Furthermore, standing back from the specific provisions Article 16.3 and looking at Article 16 in its totality, it is clear from the opening sentence that the focus of the Article is on maximising capacity availability "*at all relevant points referred to in Article 18.3.*" Article 18, in turn, provides for the approval by "*the competent authorities*" in the Member States of "*all relevant points*." This introduction of the concept of "*relevant points*" in the Regulation and its subsequent elaboration clearly imply some delineation – geographical or otherwise – in the scope of the various obligations set out in the Regulation.

In fact subsequent developments and work by ENTSOG, the ACER and the European Commission itself make it clear that the various emerging Network Codes and Guidelines on capacity allocation, on transparency and on congestion management - as anticipated in Article 16 of the Regulation - do <u>not</u> extend to all exit points. They are, in large part but with some exceptions, confined to interconnection points between systems. This is illustrated, for example, by Article 2 of the agreed Network Code on Capacity Allocation Mechanisms. It is also illustrated by Article 2.2. of Annex 1 to Regulation 715/2009 as amended by Commission Decision of 24 August 2012.

Turning to Article 22 ("Trading of Capacity Rights) of the Regulation, it is true that this does require TS0s to "*take reasonable steps to allow capacity rights to be freely tradable and to facilitate such trade…."* The significance here, however, is that the duty is to "*take reasonable steps*." It is not an absolute requirement that such trading must always be available regardless of all other circumstances or policy objectives. If that were an absolute requirement, the Article would have said so.

The CER also repeats here the earlier distinction between "trading" and "transfer" of capacity rights as set out in the Consultation Paper which is relevant to interpreting the Regulation.

On the issue of *within* day trading of capacity and whether the CER is required to go beyond the minimum requirements of the Regulation, the CER remains of the view that the inclusion of the phrase "*down to a minimum period of one day"* in Paragraph 1.1 of Annex 1 to the Regulation clearly excludes *mandatory* within day capacity trading rights, as some respondents have suggested. Again, if this were the case it begs the question: what purpose would the inclusion of the phrase "*down to a minimum period*" in the legislation serve?

Overall, therefore, the CER remains of the view that the two proposals outlined in CER 13/122 are compatible with EU law and with Regulation 715/2009 in particular.

Finally, the CER does not accept that some stakeholders have acquired constitutional property rights to secondary capacity transfers or to within day capacity products, much less that the CER is infringing such rights.

6. Alternative Options to those examined in the Consultation

The CER put forward alternative options in the Consultation to those favoured by the CER. These were:

- Mandatory Bookings
- Removal of Mandatory Bookings for NDM
- Long Term Booking Incentives

In essence respondents to the Consultation agreed with the CER in that they were not in favour of these alternative proposals. The CER will not be implementing any of the above options at this time.

7. CER Decision

The Consultation examined and consulted on two proposals for modifying the structure for revenue recovery in the gas transmission tariffs regime, both of which apply at the exit only.

The CER is now implementing these proposals.

- the removal of secondary capacity transfers at the exit

- the removal of within day purchases of short term capacity at the exit to 9:00 at D-1.

The CER considers that the key factor in allocating the cost burden between users (and user categories) should be the purpose for which the network was built – i.e. to meet each category's peak gas capacity requirement. This consideration underlies the decision to implement both proposals.

The CER considers that the removal of all secondary transfers at the exit is now warranted given the scale of reductions in primary bookings which have now emerged and given that these lower bookings are likely to prevail. If there is excess capacity at the exit from the transmission system it is inefficient, from a gas transmission system perspective, to continue to allow spare capacity to be transferred. To do so, allows parties to shift the burden of remunerating the costs of their network access onto other parties.

The CER similarly considers that the removal of within day sales of short term capacity at the exit is now warranted given the scale of reductions in primary bookings which have now emerged and given that these lower bookings are likely to prevail. The continuing presence of these products would facilitate parties (in particular the power sector) in avoiding making primary capacity bookings, thus allowing these parties to shift the burden of remunerating the costs of their network access onto other parties.

Other proposals were put forward in responses and these have been considered in detail. These proposals have not been adopted for reasons outlined in the body of this document. Other respondents suggested the CER implement a holding position with regard to the two proposals in the Consultation pending further consultation. If the CER was not to take any action now then the inequity in network costs recovery would continue and exit tariffs would significantly increase from 1st October 2013.

The above measures, along with others (WACC reduction, IC re-profiling) will mitigate an otherwise very significant transmission tariff increase to the benefit of gas customers, whilst ensuring BGN can recover the revenue necessary to fund the gas transmission system.

The CER hereby issues a direction to Gaslink pursuant Section 13 of the Gas (Interim) Regulation Act 2002 to remove all secondary capacity transfers at the exit. The Gas Code of Operations will have to be amended to reflect such direction. This is to be implemented as soon as practicable in the gas year 2013/14.

The CER hereby issues a direction to Gaslink pursuant Section 13 of the Gas (Interim) Regulation Act 2002 that the latest time for purchase of primary capacity at the exit should be changed to 09:00 on D-1. The Gas Code of Operations will have to be amended to reflect such direction. This is to be implemented as soon as practicable in the gas year 2013/14.

8. Appendix A: Impact Analysis

There are a number of steps underlying the following Impact analysis.

Firstly an expected load profile is estimated, the estimation of this load profile is in line with the methodology used in the Network Development plan, this methodology is outlined briefly below. The methodology takes an expected load profile for the NDM sector based on average temperatures. This takes an expected load profile for the I&C sector which considers GDP growth. For Power this uses forward data for energy prices to create a merit order stack for the power sector and then optimises the sector's capacity bookings under the varying constraints (i.e. Neither proposal is adopted, proposal 1 is adopted, proposal 2 is adopted, both proposals are adopted).

These expected bookings give rise to differing exit tariffs (as the overall level of bookings rises, the tariff falls). These tariffs are then used in conjunction with the expected bookings to calculate the financial impact that the various scenarios might have on the various sectors.

In this way the subject matter of this consultation is favourable to the detailed examination of the estimated impact of the various options.

Notwithstanding this, no such detailed impact analysis was included in the consultation. There were a number of reasons for this. In the main part the consultation considered the issue primarily on a principles basis, in other words, the consultation considered what split of the costs (between sectors) might be equitable and how might such a split of the costs might be approached. There were a large number of calls for the CER to carry out an impact analysis of any potential change in this split of the overall costs. Given the availability of quantitative information in this area, the CER decided to carry out such an analysis. It is important to note here that this paper is not considering increasing or decreasing the overall burden of costs but is merely considering the redistribution of these costs. As such any suggestion that a redistribution of €Xm to Sector Y is "too large" implies that that burden should be placed elsewhere. It is also worth noting that the shifts in the burden away from the power sector in particular was both rapid and recent. It was in this context that, in the consultation, the CER considered the issue primarily from a principles viewpoint.

Nevertheless, a detailed impact analysis has been carried out in this decision paper. This forms one element of information available to the CER in making its decision. However the magnitude of the redistribution of the fixed level of costs between parties does not necessarily act as a constraint in the decision making processes of the CER in this paper.

Change in exit tariff from 12/13 to 13/14 Base Case.

In this section we consider the likely "base case" for tariffs and capacity bookings that would have arisen in 2013/14 if there had been no consultation process CER 13/122. Having established this "base case", in later sections, we then examine the further impact of the various options considered in this consultation process.

The expected "base case" exit tariff would be €558.938/MWh. The prevailing 12/13 tariff is €491.313. The considerations underlying the base case 2013/14 tariff are outlined in Table 1 below.

Table 1: Tariff Rise in the Base Case

	2012/13	2013/14 Base Case
Revenues[26] €m	109.6	128.1
Annual booking MWh	201,233	214,517
Monthly booking MWh	0	5,766
Daily booking MWh	515,160	809,826
Tariff €/MWh	491.393	558.938

[26] CER 13/180. Sheet: Outputs 2

Underlying the base case 2013/14 tariff is the expected increase in bookings in 2013/14 subsequent to the decision in CER 10/089 to restrict secondary capacity transfers at the exit from 01 October 2013.

The tables below examine the evolution of primary capacity bookings by sector over the last number of years.

Table 2: Sectoral Split Bookings

Sectoral Booking	Actual *2010/11 Capacity* MWh	Actual *2011/12 Capacity* MWh	Actual *2012/13 Capacity* MWh	BASE CASE *2013/14 Capacity* MWh
Total Power Annual	118,492	115,048	86,322	85,556
DM I/C Annual	17,301	11,987	10,954	26,485
NDM Annual	99,986	99,916	98,651	97,491
Shrinkage	4,944	5,099	5,307	4,985
	240,723	232,049	201,234	214,517

Table 3: Sectoral Split, percentages of total annual capacity payments

Sectoral split	Actual *2010/11 Capacity* MWh	Actual *2011/12 Capacity* MWh	Actual *2012/13 Capacity* MWh	BASE CASE *2013/14 Capacity* MWh
Total Power Annual	49%	50%	43%	40%
DM I/C Annual	7%	5%	5%	12%
NDM Annual	42%	43%	49%	45%
Shrinkage	2%	2%	3%	2%

It can be seen from the table that both the power sector actual bookings and the proportion of bookings from that sector have declined significantly over the last period. The effect of the restriction on secondary capacity transfers can be principally be seen in the increase in primary bookings from the I&C sector in the base case with primary bookings expected to rise by c15GWh. In the base case in 2013/14 the I&C sector is satisfying all its needs from the primary market; in other words it is buying all its capacity directly from the TSO.

It must be stressed that in 2012/13 the I&C sector was purchasing the "missing" 15GWh of capacity in the secondary market, primarily from the NDM sector. Assuming that this secondary capacity was purchased at 80% of the cost of primary capacity[27], Table 4 below outlines the impact of this change on the I&C sector.

Table 4: Base Case Effect on I&C Bookings

I&C Bookings	Actual *2012/13 Capacity* MWh	BASE CASE *2013/14 Capacity* MWh	Actual *2012/13 Capacity* Cost €[28]	BASE CASE *2013/14 Capacity* Cost €[29]
Annual Primary	10,954	26,485	5,381,765	14,803,404
Annual Equivalent Secondary[30]	15,531		6,104,480	
Total	26,485	26,485	11,486,244	14,803,404

From the above it can be seen that the cost to the I&C sector will rise by c€3.3m[31] with the restriction of secondary capacity sales at the exit. It is important to note that the extent to which this increase in costs will fall on the I&C customers (as opposed to their suppliers) will depend on the extent to which the benefit of the true (on average lower) cost of secondary capacity purchases was passed on to customers.

Assuming for a moment that the I&C customers are paying the full annual primary price for the 26.485GWh of capacity in the above table, this would set the current 2012/13 payments from this sector at circa €13m (26,485MWh * €491/MWh)[32]. In this scenario, the increase in costs to this sector from 2012/13 to 2013/14 would be in the order of 14% (14.8m/13.0m). Continuing with this scenario, the presence of the level of secondary capacity purchases indicated in Table 4 above would represent a profit centre for suppliers and the restriction of this product in 2012/13 would suggest a loss of margin to the

27 This is consistent with the average floor price for BG Energy secondary capacity sales in CER 12/143.
28 The 2012/13 and 2013/14 tariffs are applied respectively.
29 The 2012/13 and 2013/14 tariffs are applied respectively.
30 For comparison purposes it is assumed that the total capacity booking is the same for both years and that the secondary capacity is bought as an annual amount.
31 Approximately 14% of this rise is due to the rise in the exit tariff from 12/13 to 13/14 Base Case
32 In reality over 50% of the capacity used to serve this sector is purchased on the secondary market at a likely average cost of €393/MWh rather than the primary price of €491/MWh

suppliers of this sector of the order of €1.5m (13.0m – 11.5m[33]). An examination of the actual bookings versus the transporter advised Maximum Daily Quantity (MDQ) for all of the customers in this sector, grouped by supplier, suggests that the quantum of euros in "lost margin" from this change should be bearable by the suppliers (bearing in mind that this is close to the maximum likely such effect on suppliers).

Notwithstanding who bears the brunt of this increase in costs, there is a significant increase in costs to be borne between I&C customers and their suppliers. The proposals in CER 13/122 will later be shown to ameliorate this effect. In any event, even where payments for a sector rise, any such increase in payments (or more accurately proportion of total payments) from that sector might be appropriate in equity terms.

Payments from the power sector will also change from 2012/13 to the base case in 2013/14, this is outlined in Table 5 below.

Table 5: Base Case Effect on Power Sector

Power bookings	Actual *2012/13 Capacity MWh*	BASE CASE *2013/14 Capacity MWh*	Actual *2012/13 Capacity Cost €*	BASE CASE *2013/14 Capacity Cost €*
Annual Primary	86,322	85,556	42,411,095	47,820,652
Monthly Primary		*5,766*		416,298
Daily Primary	*515,160*	*809,826*	495,586	3,583,938
Annual Equivalent Secondary[34]	2,699		1,060,929	
Total Annual	89,021	85,556	43,967,611	51,820,889

From the above it can be seen that the cost to the Power sector will rise by c€7.8m between 2012/13 and 2013/14 with the restriction of secondary capacity sales at the exit. Table 3 which identifies the sectoral splits, shows that the percentage of total bookings made by power declines from 43% to

[33] €11.5m would be the cost of 15,531MWh of secondary capacity if purchased at €393/MWh plus the cost of 10,954MWh of primary capacity purchased at €491/MWh.

[34] For comparison purposes it is assumed that the quantity of secondary capacity bought in 2012/13 (expressed as an annual amount) is the same as the quantity of short term capacity purchased in the 2013/14 Base Case. This is consistent with the assumptions used for the I&C sector. In the case of the power sector this is likely to be a conservative estimate of the actual secondary capacity purchases in 2012/13.

40%, while the split booked by the I&C sector has risen from 5% to 12% (see Table 3).

Given the restriction on secondary capacity sales, the modelling carried out to estimate the bookings for 2013/14 assumes that all the power stations optimise capacity bookings as if they were under the control of a single operator. This mimics the effect of what some of the power sector respondents called the active and efficient market for secondary capacity between power stations. In their view this market would allow the "right" amount of capacity to be purchased by the power sector as a whole and the unregulated secondary market between the participants could allow (at least between the power sector participants) the "right" price for flexibility to be discovered[35]. The modelling carried out in effect mimics this "unseen hand of the market", which allows the power sector to purchase the minimum amount of capacity at the regulated prices.

Of course the burden of remunerating any capacity that was not booked or paid for by the power sector then falls onto the remaining sectors. Thus any such unregulated "efficient" market between power generators exists only as a subset of the overall regulated market and any decision to retain or remove any such market must be considered in the light of its interactions with the remaining parts of the overall regulated market.

The impact of the change from 2012/13 to the 2013/14 base case on the NDM sector is outlined in Table 6 below.

Table 6: Base Case Effect on NDM Sector

NDM	Actual *2012/13 Capacity MWh*	BASE CASE *2013/14 Capacity MWh*	Actual *2012/13 Capacity Cost €*	BASE CASE *2013/14 Capacity Cost €*
Annual Primary	98,651	97,491	48,468,529	54,491,313
Total	98,651	97,491	48,468,529	54,491,313

35 Of course the impact of the regulated prices for flexible products might impair the secondary markets ability to find the "right" price for flexibility. Consider a market with 2 parties; party A has spare capacity that cost €1m. If party B needs this capacity for 10 days, the price might be €100k/day. If party B needs the capacity for 1 day, the price might be €1m/day. If the TSO is also in the market and the ex-ante regulated price for a day's capacity is €2,739/day (€1m/365) then the "right" price for flexibility is not discovered.

From the above it can be seen that the cost to the NDM sector will rise by c€6.0m from 2012/13 to the base case[36], driven by the increase in tariff with no change in bookings. This is in fact less than the 14% rise in the overall exit tariff from 12/13 to 13/14 Base Case outlined in Table 1. As above this is clear from Table 3 identifying the sectoral splits, where it can be seen that the percentage of bookings made by the NDM declines from 49% to 45%.[37]

[36] It is important to recall that the restriction of secondary capacity transfers at the exit is not the only change between 2012/13 and the base case in 2013/14, other changes include the required revenue is increasing and also the power sector is assumed to continue optimising its bookings.

[37] Though the NDM sector will be net losers in the restriction of secondary capacity sales at the exit as it will lose the revenue from the secondary capacity sales at the exit that would otherwise have arisen.

Change in exit tariff from 13/14 Base Case under various scenarios

In this section we consider the possible changes from the "base case" for tariffs and capacity bookings that would arise in 2013/14 in various scenarios.

The expected "base case" exit tariff would be €558.938/MWh. The tariffs that have been modelled for each scenario and the various expected capacity bookings are shown below.

Table 7: Overall Effect of Consultation Proposals

	2013/14 Base Case	Proposal 1	Proposal 2	Proposal 1&2	Upper bound
Annual booking MWh	214,517	220,086	232,512	235,520	245,656
Monthly booking MWh	5,766	6,137	1,120	17,358	5,986
Daily booking MWh	809,826	496,960	367,919	0	0
Tariff €/MWh	558.938	544.795	515.679	509.093	For illustration only

Table 8: Expected Bookings Across Sectors

		BASE CASE	Proposal 1	Proposal 2	Proposal 1 & 2	Upper bound
Sector		*2013/14 Capacity* MWh	*2013/14 Capacity* MWh	*2013/14 Capacity* MWh	*2013/14 Capacity* MWh	*2013/14 Capacity* MWh
Total Power Annual		85,556.3	91,124.9	103,551.4	106,559.4	116,695.0
Total Power Monthly		5,766.2	6,137.2	1,120.4	17,358.5	5,985.9
Total Power Daily		809,826.3	496,959.9	367,918.7	0.0	0.0
DM I/C Annual		26,484.9	26,484.9	26,484.9	26,484.9	26,484.9
NDM Annual		97,490.8	97,490.8	97,490.8	97,490.8	97,490.8
Shrinkage		4,985.0	4,985.0	4,985.0	4,985.0	4,985.0
TOTAL Annual		214,517.0	220,085.6	232,512.1	235,520.0	245,655.7
TOTAL Monthly		5,766.2	6,137.2	1,120.4	17,358.5	5,985.9
TOTAL Daily		809,826.3	496,959.9	367,918.7	0.0	0.0

The above table shows the expected bookings by the various sectors in the scenarios. No short term sales are expected from the I&C of the NDM sectors.

The expected bookings shown above for proposal 1, proposal 2 and both proposal 1&2 were derived from an optimisation programme which considered the various constraints imposed by the proposals. This used forward data for energy prices to create a merit order stack for the power sector and then optimised the sector's capacity bookings under the varying constraints.

In the modelling no increase in bookings was predicted from the I&C sector resulting for the implementation of any of the proposals (there would already have been an increase from 2012/13 to the base case following the restriction of secondary capacity transfers).

Proposal 1 removes the ability of the power sector to transfer "spare" capacity between power stations. In this scenario the modelling assumes that each station will optimise on an individual basis (given the same assumptions about merit order). This leads to an increase in expected in annual and monthly bookings from the power sector with a decrease in the expected purchases of daily short term purchases from this sector.

Proposal 2 removes the ability to purchase within day products at the exit but it allows the power stations to transfer “spare” capacity between themselves. In this case (as in the base case) all the power stations are modelled as if they were all under the control of the one operator (or as if there was just one power station). In this scenario the modelling predicts a further increase in annual bookings from the power sector with continuing (but declining) monthly and daily (day ahead) purchases.

The implementation of both proposal 1 and 2 sees the power stations optimising on an individual basis (the power stations can no longer transfer “spare” capacity between themselves). This scenario sees a further increase in annual capacity bookings. In this scenario the purchase of monthly capacity is cost effective for the power generators whereas no daily bookings are predicted.

In reality the expected merit order will change over time as energy prices change. A change in the merit order over time would still allow power stations to purchase additional capacity if needed. In this context daily (or more appropriately day ahead) purchases of capacity might actually arise in practice. Of course if both proposals 1 and 2 are implemented then once purchased, any capacity to hand cannot be sold on. Given the uncertainty that can exist around energy prices this might mean that significant quantities of daily capacity might be bought in an attempt to minimise the chances of a power station holding “spare “capacity.

The upper bound estimates were implemented as an upper limit cross check of the above modelling. In this case a subjective view was taken on a case by case basis for each of the power stations in the gas sector based on recent running regime. In simple terms it was assumed that some stations would book 95% of the transporter advised MDQ (such as mid merit plant)[38]. It was assumed that other (peaking) plants that had not been booking annual gas capacity[39] would not book any annual capacity at all. In the case of one plant which had been booking some capacity recently and which the optimiser had

[38] If there is a chance that on any given day a power station might be called upon to run flat out for 24hrs then it might be appropriate to purchase an annual strip close to the MDQ.
[39] Technically some of the plants were booking 1kWh of annual capacity at a cost of 49c each for 2012/13

assumed it would continue to book some annual capacity, it was assumed for this scenario that this plant would not book any gas capacity at all. On the whole this subjective cross check on the optimiser led to what is described as an upper bound scenario. Please note this scenario has not been used for tariff calculating purposes but has been included as an upper boundary of the expected impact of the proposals on the electricity sector.

Table 9: Expected Revenues Across Sectors

		BASE CASE	Proposal 1	Proposal 2	Proposal 1 & 2	Upper bound
Sector		*2013/14 Capacity €*	*2013/14 Capacity €*	*2013/14 Capacity €*	*2013/14 Capacity €*	*2013/14 Capacity €*
Total Power Annual		47,820,652	49,644,400	53,399,287	54,248,628	58,982,230
Total Power Monthly		416,298	431,869	74,625	1,141,456	390,795
Total Power Daily		3,583,938	2,143,677	1,502,230	0	0
DM I/C Annual		14,803,404	14,428,828	13,657,695	13,483,265	13,386,492
NDM Annual		54,491,313	53,112,501	50,273,959	49,631,884	49,275,663
Shrinkage		2,786,306	2,715,803	2,570,660	2,537,829	2,519,614
TOTAL Annual		117,115,370	117,185,730	117,330,940	117,363,778	121,644,386
TOTAL Monthly		416,298	431,869	74,625	1,141,456	390,795
TOTAL Daily		3,583,938	2,143,677	1,502,230	0	0

Table 9 above shows the expected revenues from each sector under the various scenarios. For the purposes of the impact assessment, the tariff prevailing in the upper bound scenario was calculated at €505/MWh. Revenues from short term capacity sales were assumed to be sold at the average multipliers of 155% and289% for daily. The total revenue in each scenario does vary as the tariffs are calculated ex ante whereas the revenues from the short term sales can vary under each scenario.

The net revenue from power generation increases by c€3.5m moving from the base case to implementation of both proposals in the consultation (with an upper bound increase estimated at €7.2m). The revenue from the other sectors declines at the same time. There are significant variations of this impact within the power sector. Higher load factor sites can (depending on their view on bookings) can see reduced costs while peaking plants might face the choice of paying significantly increased capacity charges or not offering gas capability to the SEM. From the gas system perspective, it is considered likely that the "gains" in bookings from higher load factor power stations will outweigh the losses in revenue from peaking plant (most of which contributed very little revenue to the gas system in any event). Issues such as how the increase in costs of up to €7.2m that the electricity sector might face or how the effects of the distribution of the those costs within electricity sector are dealt with (or remunerated) in the electricity market are not dealt with in this paper.

Table 10: Sector Split of Total Revenues

	BASE CASE	Proposal 1	Proposal 2	Proposal 1 & 2	Upper bound
Sector Split of total revenues	*2013/14 Capacity* % of total	*2013/14 Capacity* % of total	*2013/14 Capacity* % of total	*2013/14 Capacity* % of total	*2013/14 Capacity* % of total
Total Power Annual	39%	41%	44%	45%	47%
Total Power Monthly	0%	0%	0%	1%	0%
Total Power Daily	3%	2%	1%	0%	0%
DM I/C Annual	12%	12%	11%	11%	11%
NDM Annual	44%	43%	41%	41%	40%
Shrinkage	2%	2%	2%	2%	2%

This table shows the percentage split of the total revenues[40] that is borne by each sector in each scenario The split being borne by power increases from 39% to 45% (with an upper bound of 47%). The I&C sector stays reasonably steady at 11 and 12% with the Residential sector split falling from 44% to 41% (with an upper bound of 40%)[41].

[40] Note this table references the split of total revenues whereas table 3 references the split of total annual revenues only. Given the use of daily and monthly short term bookings in these scenarios it was considered that best measure was total revenue. The revenue calculation assumes the current average short term multipliers apply.
[41] The residential split changes more than the I&C split because while both residential and I&C costs fall by the same proportion, the absolute change is 3.5 times greater in residential, thus the percentage of the split that residential pays (of the relatively fixed overall costs) changes more significantly.

Table 11: Sector Revenue Vs Base Revenue

	Proposal 1	Proposal 2	Proposal 1 & 2	Upper bound
Sector Revenue Vs base revenue	*2013/14* *Capacity* % change	*2013/14* *Capacity* % change	*2013/14* *Capacity* % change	*2013/14* *Capacity* % change
Total Power Annual	101%	106%	107%	115%
DM I/C Annual	97%	92%	91%	90%
NDM Annual	97%	92%	91%	90%
Shrinkage	97%	92%	91%	90%

This table shows the percentage change (i.e. 100% is no change) in revenues from each sector under each scenario.

It can be seen that the power sector revenues increase from the base case while the revenues from the other sectors decline from the base case.

9. Appendix B: Code of Operation Definitions

It is useful to examine the following definitions from the Gaslink Code of Operations:

Part C : 1.1.15

“Secondary Capacity” : Secondary Capacity means capacity of an individual category that is held by a Shipper on a Day pursuant to an Entry Capacity Trade (which shall be made with respect to the same Entry Point) or an Exit Capacity
Transfer in respect of the Day or a LDM Supply Point Capacity Title Transfer (which shall be made with respect to the same LDM Supply Point) for the Day as the case may be;

Part C 8.1.1

“Exit Capacity Transfer” means the transfer by a Transferor Shipper of Retained Primary Exit Capacity to a Transferee Shipper to increase such Transferee Shipper’s Active LDM Exit Capacity or to increase the Active DM Exit Capacity or Active NDM Exit Capacity of the Transferee Shipper.

Part C 3.1.2

"Entry Capacity Trade" means an arrangement between a Transferor Shipper and a Transferee Shipper whereby certain of the rights of the Transferor Shipper in relation to Entry Capacity may be exercised by the Transferee Shipper in accordance with the provisions of this Code and the Transferee Shipper shall be subject to certain obligations in relation to such capacity.

Part C 5.1.

“Entry Point Transfer” means A Shipper may in accordance with the following provisions of this Section 5.1 transfer all, or part, of its Primary Entry Capacity held pursuant to an Entry Capacity Booking which is Multi-Annual or Annual in duration (but excluding any Primary Entry Capacity booked pursuant to a Treaty
Entitlement) from an Entry Point (the "Original Entry Point") to an alternative Entry Point or to a Proposed Entry Point (the "New Entry Point") by way of a transfer of Entry Capacity to such New Entry Point ("Entry Point Transfer") in accordance with Section 5 of the code.