Commission for Energy Regulation
An Coimisiún um Rialáil Fuinnimh

# Common Arrangements for Gas

# Transmission Tariff Methodology and Regulation in Ireland and Northern Ireland

## Consultation Paper

27th June 2008

Utility Regulator
ELECTRICITY GAS WATER

## Contents

# Executive Summary

## Introduction

The purpose of this document is to examine the options available for the development of harmonised transmission tariffs in Ireland and Northern Ireland. The paper also deals with issues arising from the effect of the expected decline in utilisation of the interconnectors (ICs) on the marginal cost pricing system under an entry/exit regime.

The intention to reform is embodied in the Memorandum of Understanding (MoU) signed between the Commission for Energy Regulation (CER) and the Northern Ireland Authority for Utility Regulation (NIAUR) (the Regulatory Authorities) in February 2008 (see CER/08/055), specifically:

"…to establish All-Island Common Arrangements for Gas whereby all stakeholders can buy, sell, transport, operate, develop and plan the natural gas market north and south of the border effectively on an all-island basis. This means that variations in the price and conditions on which gas is bought and sold will be determined by market conditions and economics, not by variations in regulatory arrangements."

## Reform Options

There are a range of reform options that can be considered, these include both the broad tariff methodology as well as the detail of the form of control.

Within the broad tariff methodology the options to consider include:

- Postalisation; and
- Entry-exit – with the following key options for entry points:
    - a single entry point (all existing and future "entry" transmission pipelines combined);
    - a combined Moffat entry point (incorporating the Scotland to Northern Ireland Pipeline (SNIP) and the southern ICs); and
    - a continuation of the existing separate entry points.

  Within the exit reforms there are three possible options:

    - A single exit point;
    - Two exit points – one in Ireland and one in Northern Ireland; and

- Multiple exit points.

Options for reforming the detailed design of the regime include:

- harmonising the capacity/commodity split; and
- harmonising the way in which tariffs are smoothed.

As mentioned above, the paper also deals with issues arising from the effect of the expected decline in utilisation of the ICs on the marginal cost pricing system under an entry/exit regime. This issue is unrelated to the Common Arrangements for Gas (CAG) and not a consequence of CAG. However we are dealing with this issue at this time as some of the proposed tariff methodologies interact significantly with this issue.

Under an entry/exit regime the marginal source of gas sets the price of gas at the Irish Balancing Point (IBP). Given the demand for gas in Ireland, it is assumed that the ICs are the source of marginal gas; consequently the cost of gas at the IBP can be viewed simply as Great Britain (GB) gas price (known as the National Balancing Point (NBP)) plus IC transmission charge. Thus the price of gas in Ireland (IBP) is higher than the gas price in GB. This acts as an incentive to producers of gas in Ireland (e.g. from Ireland's offshore fields or Liquified Natural Gas (LNG)). However as IC utilisation declines, the IC transmission charge rises and IBP rises. Depending on the tariff methodology chosen (i.e. if an entry / exit regime is chosen) this rise could become very significant unless mitigated by some other mechanism. The mechanisms considered focus on reducing the rise in the IC transmission charge as below:

- Reducing the annual revenue requirement of the ICs by:
  - Establishing a Public Service Obligation (PSO) levy to defray some of the costs
  - Buying down some of the costs through changing the Regulatory Asset Base (RAB) by moving or suspending some of the asset value during the trough in consumption
  - Cutting the allowed rate of return.

- Reducing the effect of the decline in utilisation by:
  - Reprofiling (averaging out the trough in consumption)
  - Setting a minimum booking level (filling in the trough)
  - Reducing the depreciation level during the trough in consumption

**Assessment of the options**

A consideration of the various reform options against four key criteria is undertaken in the report. The four criteria are:

- Development of the gas industry;
- Protection of consumers;
- Security of supply; and
- Promotion of competition.

When using these criteria we find the following:

Postalisation may have a positive impact on the development of the gas industry and the protection of consumers but could have negative impacts on security of supply and promotion of competition;

Entry reforms that link the ICs with other entry points may have little impact on the development of the gas industry but are likely to have major positive impacts on the protection of consumers (although the degree of this impact depends on whether the utilisation problem has been separately addressed) and possibly mixed impacts on security of supply and promotion of competition (the impact may be bad for producers but good for consumers and the broader economy); and

Exit reforms could have a mixed impact on the development of the gas industry – the degree of cost reflectivity and geographic averaging varies depending on how many exit points there are, although all options support financial viability. The impact on consumers also varies according to the number of exit points, the fewer the exit points the more stable the tariffs. Security of supply and promotion of competition are unlikely to be significantly affected by the choice of exit option.

Other tariff design issues are also assessed. These include:

Capacity/Commodity split – where the impact on the development of the gas industry is found to be potentially positive but small (if more of the final price depends on the actual commodity flowed than peak capacity, then intermittent and low usage customers are likely to be encouraged). The impact on the protection of consumers is likely to be mixed since some consumers will benefit at the expense of others. Security of supply is likely to be only lightly affected although this will depend on what charges storage has to pay – if it pays commodity at

three different points and capacity at only one it is likely to benefit when capacity tariffs have the greatest impact on prices. Finally, it is not clear whether any impact on the promotion of competition would be seen.

Tariff smoothing could be beneficial to the development of the gas industry and the protection of consumers since the variability in tariffs and consequent end-user prices would be minimised (although this does depend in part on the how the question of the IC utilisation is addressed) and would not increase geographic averaging. However, cost reflectivity on a year-on-year basis would be affected and this might cause some financial viability concerns – especially important for the mutualised assets in Northern Ireland. Security of supply might be affected since the incentive earned by the producers would be affected, although whether this is negative is unclear. Finally, it is not clear that a reform of the tariff smoothing system would have any impact on the promotion of competition.

**Impact of possible reforms on prices**

Postalisation has the largest impact and reduces prices for Ireland's consumers while minimising the increases to consumers in Northern Ireland, this is achieved by removing the incentive to indigenous producers present in entry exit regimes, thus the cost to consumers is reduced to the "Cost Base" in Table 1. This is, however, achieved at the expense of the incentive for security and diversity of supply and would significantly reduce the existing benefit to producers and shippers. Further, there would be implementation issues associated with handling the common currency and revenue transfer between the jurisdictions, especially as the simplest route for redistributing this revenue transfer is through the separate exit points, which would be lost in a fully postalised regime.

Combining some or all the entry points still reduces the IBP and allows customers in Ireland to pay less for their gas – although the increase in prices for Northern Ireland are larger than under postalisation. In all bar a single entry point there is some retention of the benefit to existing and future producers and shippers of indigenous gas. For example, combining the various GB interconnectors into a single Moffat entry point would leave indigenous producers and shippers with significantly less of the benefit that they would receive over 10 years if no reform took place. Any option that combines SNIP with one or more of the southern entry points will create a common currency issue that would need to be addressed.

Table 1 below provides an overview summary of the impact that different tariff methodology reforms have on customers and indigenous producers and shippers.

**Table 1: Impact of different approaches, cost and savings to customers.**

| Approach | Total cost (€m) | Additional cost to customers over cost base | |
|---|---|---|---|
| | | In €m | In c/therm |
| Cost base* | 2,549 | - | - |
| Charge at IC** (Do nothing scenario) | 9,159 | 6,610 | 22.5 |
| Charge at Moffat*** | 3,649 | 1,100 | 3.7 |
| Charge at All-entry**** | 2,554 | 5 | 0.0 |

Note: – assumes whole island is operating an entry-exit regime and that no Non Daily Metered (NDM) discount is provided;

*Cost base is the sum of the revenue requirements for each transmission asset over the period. One consequence of Postalisation is that it removes the incentive to indigenous producers present in entry exit regimes, thus the cost to consumers is reduced to the "Cost Base" above.

**Charge at IC implies that entry points are kept separate and the Ireland ICs are the marginal source of gas. This is essentially a do nothing scenario.

***Charge at Moffat implies that the three Moffat interconnectors are combined

**** Charge at All-entry implies a single entry point (all entry points combined)

For the exit zones, a key consideration is the degree of cost reflectivity and what it achieves. More exit points should increase cost reflectivity but could also have important distributional impacts for customers, especially if rural exit points lead to much higher prices. Two exit points have the advantage of continuing the existing approach and allowing a route for revenue transfer between jurisdictions. This would be lost if a single exit zone was adopted.

Within the detailed design issues the most significant is the one relating to mitigating the effect of declining IC utilisation on IBP. What is obvious is that under the existing regime it is difficult to foresee a mitigation strategy that has a sufficiently significant impact to address the concerns inherent in the existing regime. Further, reprofiling is simply concerned with moving costs between time periods rather than removing them. However, the idea of ensuring a minimum

level of capacity booking on the ICs to ensure security and diversity of supply may be one that is worth further consideration if other broad regime change options are not undertaken.

**Next steps**

Specific questions are listed throughout the document. The Regulatory Authorities would appreciate, by 1st August 2008, comment and feedback on these questions as well as any other thoughts and points that respondents wish to make.

# 1. Introduction

## 1.1. Purpose of this document

The purpose of this document is to examine the options available for the development of harmonised transmission tariffs in Ireland and Northern Ireland. The paper details the existing transmission systems and tariff structures in each jurisdiction, sets out the main issues and examines the harmonisation options available. The paper also sets out the proposed criteria by which the various harmonisation options should be assessed. The paper also deals with issues arising from the effect of the expected decline in utilisation of the IC on the marginal cost pricing system under an entry/exit regime. This issue is unrelated to CAG and not a consequence of CAG and would impact on the IBP, even if CAG were not to take place. However we are dealing with this issue at this time as some of the proposed tariff methodologies interact significantly with this issue.

## 1.2. Structure of the document

This remainder of this document is set out as follows:

Section 2: Review of the existing transmission tariff methodologies in the two jurisdictions

Section 3: Proposed assessment criteria by which any reform option can be assessed

Section 4: Possible reform options to be considered

Section 5: Assessment of the reform options

Section 6: Next steps.

## 1.3. Common Arrangements for Gas

On 14th February 2008 the Commission for Energy Regulation and the Northern Ireland Authority for Utility Regulation (NIAUR) (the Regulatory Authorities) signed an MoU which sets out a vision for Common Gas Arrangements for Gas in Ireland and Northern Ireland. Since then, the Regulatory Authorities have developed a detailed work plan for the project. The work plan was published on the CER and the Utility Regulator websites on 22nd May[1].

[1] CER/08/086

The development of CAG comes on foot of the establishment of the Single Electricity Market (SEM) which became operational on 1st November 2007. The SEM is the first cross-jurisdictional electricity market of its kind in Europe and represents a new culture of cooperation in the energy field.

The development of the CAG also fits in with current aspirations at European Union level. The European Commission has put in place a legislative framework within which all member states are working to achieve a Single Gas Market. This Single European Market is designed to bring benefits to all European citizens and contribute to Europe's competitiveness. Both Ireland and Northern Ireland are committed to the development of a Single European Gas Market and the development of the CAG demonstrates this and acts as an example for other member states.

## 1.4. Reform of Transmission Tariffs

The desire to reform transmission tariffs is reflected in the MoU signed between the Regulatory Authorities in February 2008[2]. Within the MoU there is also a strong statement about the objectives for this harmonisation:

"…to establish All-Island Common Arrangements for Gas whereby all stakeholders can buy, sell, transport, operate, develop and plan the natural gas market north and south of the border effectively on an all-island basis. This means that variations in the price and conditions on which gas is bought and sold will be determined by market conditions and economics, not by variations in regulatory arrangements."

Four pragmatic reasons can be considered:

- common incentives within an integrated network – with the gas system becoming more integrated, through the South-North pipeline, it is important to consider the implications of different tariff methodologies in each of the jurisdictions (e.g. the distortional effect they may have on the SEM);
- reliance on flows from Ireland – linked to the above point is the fact that Northern Ireland is likely to become increasingly dependent on flows of gas from Ireland through the South-North pipeline as SNIP becomes fully utilised;
- competition – create a larger market which is able to attract more players and which has the critical mass for competition to extend to more consumers; and

[2] CER/08/055

- attract investment to enhance security and diversity of supply – as with the above point, a larger market should be more attractive to investors and this should allow greater security and diversity of supply to be achieved.

All of these factors create practical pressure for reform and harmonisation of tariff methodologies.

Further, as mentioned above and discussed in more detail in Section 2 of this report, pressure for reform has been growing in Ireland owing to the impact that new indigenous gas developments like Corrib and the proposed Shannon LNG terminal have on tariffs for all users of the gas system. In Northern Ireland there is also increasing interest in the development of storage, with significant work already underway for a potential site at Larne and this may be partly dependent on the final transmission tariff methodology chosen.

As part of the CAG, a Cost Benefit Analysis (CBA) is being developed which will set out the benefits associated with the introduction of the new common arrangements. This CBA will be published and subsequently updated to reflect different stages in the project.

## 1.5. Request for comment

The Regulatory Authorities invite comment from interested parties on the proposals set out in this paper by close of business on **1st August 2008.** The Regulatory Authorities intend to publish all comments received – those respondents wishing for certain sections of their submission to remain confidential should submit the relevant sections in an appendix marked confidential.

Comments on this paper should be sent, preferably in electronic format, to:


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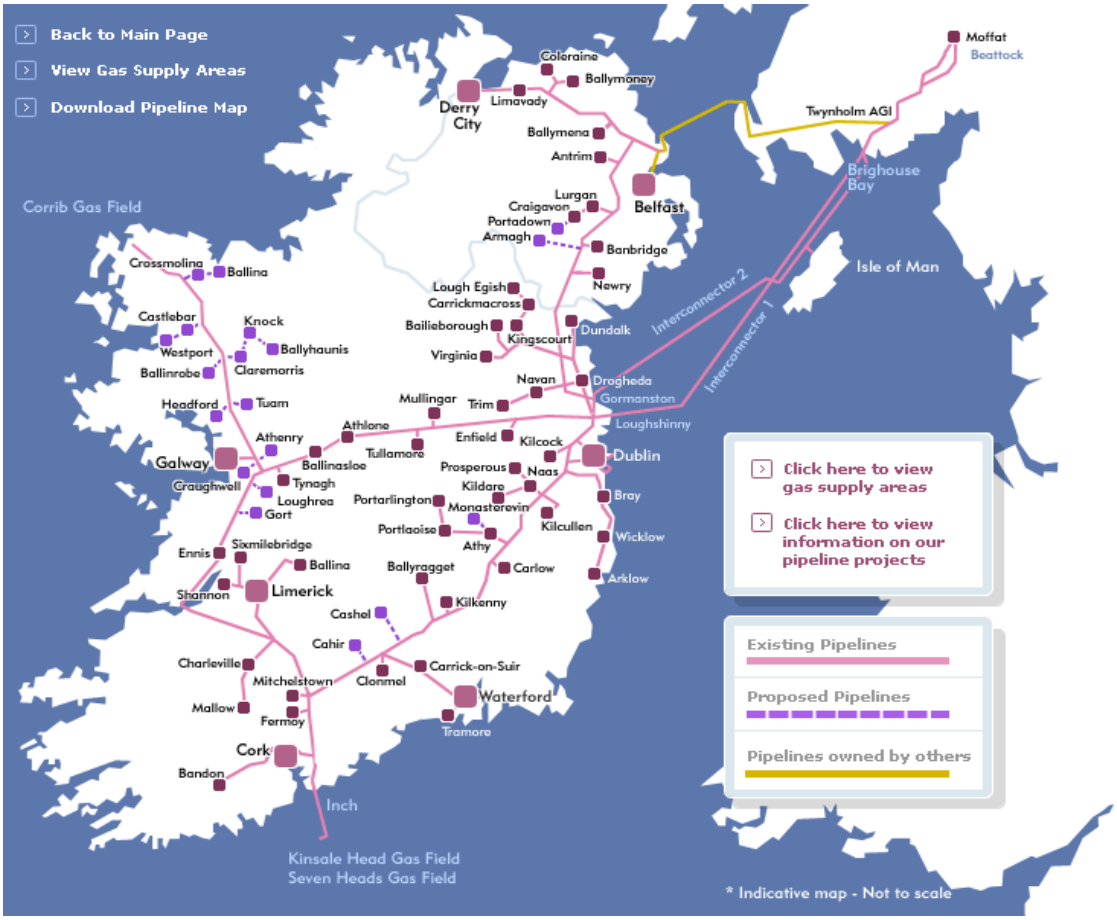
## 2. Existing Transmission Tariffs

This section of the report provides an overview of the existing tariff methodologies. Before considering these it is worth providing an overview of the transmission system – as shown in Figure 2.1. As can be seen, there are three interconnectors between Scotland and Ireland (one to Northern Ireland – referred to as SNIP – and two to Ireland – referred to as IC1 and IC2) and one pipeline linking an existing gas field (in Ireland landing at Inch from the Kinsale gas field). A new connecting pipeline from the Corrib Gas Field to the Mayo-Galway pipeline is expected to be operational from October 2009. Further to this, an LNG terminal (Shannon LNG) has received planning permission in the South West of Ireland and is planned to come into commercial operation in 2012. In addition a storage facility is proposed at Larne in Northern Ireland and is planned to be operational from 2014/15**.**

**Figure 2.1: Gas Transmission Network in Ireland and Northern Ireland (Source: Bord Gáis Networks)**




In terms of the onshore pipelines there are two existing systems. The Northern Ireland onshore system comprises three connected transmission pipelines – the Belfast Gas Transmission Ltd

pipeline (formerly the Phoenix pipeline), the North-West pipeline and the South-North pipeline connecting the Ireland and Northern Ireland onshore systems. The Ireland onshore system is the main transmission network in Ireland.

## 2.1. Tariff Methodology

There are three aspects to discuss here, the two different methodologies in place in the two jurisdictions as well as the associated cost basis for charging.

### 2.1.1. Postalisation

Currently transmission tariffs in Northern Ireland are postalised. Any transmission user pays the same per unit charge as any other transmission user, no matter where gas is taken off the transmission system and this charge includes both the entry (the transportation of the gas to the onshore system) and exit (transportation of the gas through the onshore system) costs. This is in part a reflection of the fact that all users are supplied via SNIP and consequently have the same marginal source of gas. It also, however, reflects the legislative position where the 2003 Energy (Northern Ireland) Order requires the Utility Regulator to base tariffs on a postalised system – see annex 2 for this as well as other objectives and functions imposed on the Utility Regulator.

### 2.1.2. Entry and Exit

In July 2003 the CER directed Bord Gáis Networks (BGN) to implement an Entry/Exit regime to replace the then point to point regime[3]. Under this approach each separate entry and exit system has a tariff. The separate entry points that currently exist are:

- Inch – the entry point for the Kinsale and Seven Heads gas fields (and associated storage); and
- IC 1 and 2 – the single entry point for the gas shipped from GB.

In the short to medium term two more entry points are expected to become operational:

- Bellanaboy – the entry point for the Corrib gas field; and
- Shannon – the entry point for the proposed LNG terminal.

[3] CER/03/184

A single exit point relating to the onshore system exists whereby the same tariff is charged no matter where the gas is taken off the system.

The operation of the entry and exit system can interact significantly with the form of pricing (marginal or average) and have a major impact on customers. This interaction is described below.

### 2.1.3. Marginal and average cost pricing

Linked to the discussion above about postalisation and entry-exit charges is the question of the form of charging. Specifically:

- average cost pricing where all customers pay the same tariff; or
- marginal cost pricing where all customers pay the same tariff but it is based on the tariff for the marginal unit of consumption.

Postalisation implies average cost pricing while an entry/exit system is associated with marginal cost pricing[4].

The system currently in place in Ireland is an entry/exit system with a form of marginal cost pricing – this is enshrined in the IBP. All customers pay an entry cost based on the transmission tariff for the marginal source of gas – although the transmission tariff itself is based on the average cost of using that entry point. Given the demand for gas in Ireland it is assumed that the ICs are the source of marginal gas and consequently every customer pays the IC transmission charge. This does not mean that the network operator, BGN, receives that transmission charge for every capacity booking or unit of gas transported. Rather it receives the regulated transmission tariffs for each of the entry points and the shipper/producer gains the benefit of any difference between the actual entry tariff and the marginal (IC) entry tariff reflected in the IBP. This acts as an incentive to producers of gas in Ireland (e.g. from Ireland's offshore gas fields and LNG) – discussed in more detail in Section 2.1.4 below.

With only two entry points and one of those relatively small compared to the other, this system was workable. However, as new entry points arise and utilisation of the IC falls the charge for the IC will rise and the cost of gas for all consumers will increase. This rise in IC tariff as utilisation decreases is illustrated in Figure 2.2. This figure reflects the annual required revenue and the impact of a significant reduction in capacity utilisation – in this case the reduction is

[4] Although in principle an entry-exit regime could support average cost pricing it would then effectively be a postalised regime.

driven by the introduction of Corrib. A similar impact would be seen if/when Shannon LNG comes onstream, or another indigenous source – provided that the IC is still the marginal source of gas, i.e. total indigenous production is insufficient to meet total demand.

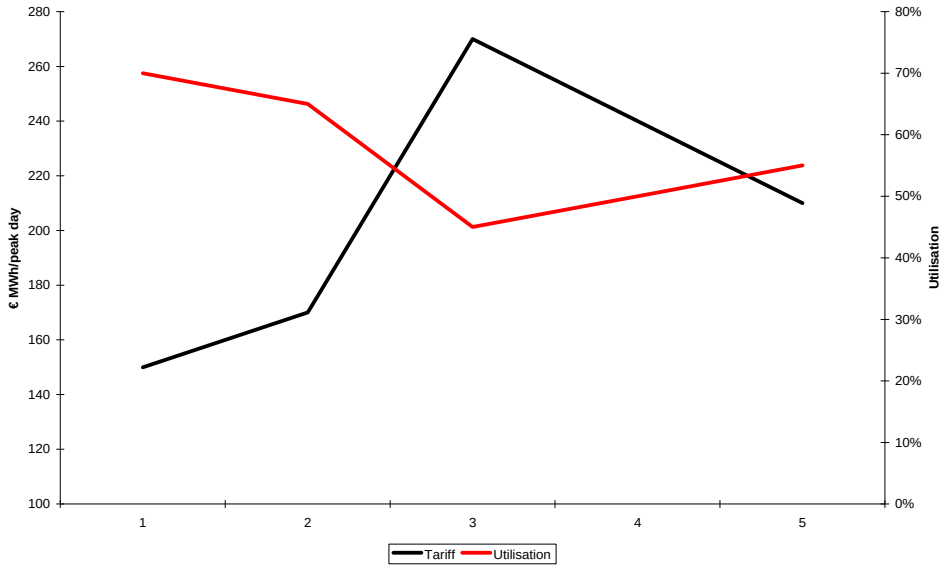



**Figure 2.2: Illustrative impact of reducing capacity utilisation at IC (€ - MWh/day)**

Of course, some volatility in prices as utilisation changes is to be expected. The problem in Ireland's existing entry-exit system is that a significant change in utilisation can occur as new indigenous sources become available owing to their size relative to the existing IC capacity. This can have a major impact on prices for everyone owing to the operation of the IBP. This type of volatility could be time limited (as with Corrib which will come onstream and then tail off relatively quickly) or a one-off shift (as with Shannon since once onstream the access to LNG from around the world allows production to be maintained for the life of the LNG facility).[5] Clearly correcting for this type of impact is beyond the normal tariff methodology and consequently should be addressed through alternative measures rather than changing the tariff methodology. This is discussed and analysed further in Sections 4.4 and 5.4.

[5] The first impact is effectively asset utilisation being suspended while the latter is effectively stranding of the day-to-day operation of the asset.

### 2.1.4. Producer incentives

One consequence of the existing entry-exit regime in Ireland is that a "producer incentive" is created since they get to retain the difference between the IBP and the cost of their gas at the specific entry point. Normally the key incentives for producers are:

- the relative cost of gas extraction to the international price of gas; and
- tax and other Government provided incentives.

The relative importance of any difference in actual entry tariffs and the marginal source of gas entry tariff is likely to be small compared to the more traditional relative cost of gas and tax incentives for field development. However, linked to the point discussed above, if the price of the marginal entry point increases owing to a change in utilisation then it is possible to envisage scenarios where the impact on producers is more significant – possibly accounting for a few cents/therm. Of course, this incentive is created by all consumers in Ireland paying the higher price created through the reduced utilisation of the marginal entry point.

The situation is likely to be different for LNG provision since the cost of the gas is likely to be close to the international price – this is especially important since the NBP, the price of gas in GB, will be set by LNG as it increasingly become the marginal source of new gas and NBP is a key component of the IBP. Consequently any difference in transmission entry tariffs will be a major part of the margin earned by the LNG importer. Although the primary driver for profitability of storage is the ability to exploit the seasonal difference in gas prices, the difference in transmission tariffs may also have an impact. When assessing different possible reform options later in the paper, their implications for producers/LNG/storage are considered and, of course, by implication the costs for consumers.

## 2.2. Role of non annual gas capacity products

There are currently a number of non annual gas products available in Ireland and Northern Ireland. To date though there has been no harmonisation of these products. Short term products are available in Ireland since October 2007. They are not available to date in Northern Ireland. Both jurisdictions have piloted an inventory product with Ireland making it available to all Moffat shippers since April 2008. Northern Ireland has an interruptible product available on the SNIP. In Ireland, principles and business rules have been developed for an interruptible Moffat product but it will not be systemised at present. Ireland also has a storage tariff available at Inch. With the potential development of a storage facility at Larne, a storage tariff will need to be developed

in Northern Ireland also. Table 2.2 sets out the differences and commonalities between tariff structures in the two jurisdictions which includes information on gas products.

## 2.3. Tariff Structure

Within the question of the tariff structure there are further issues to consider:

- the split between fixed and variable pricing – in gas this means the capacity versus commodity split; and
- whether smoothing of tariffs during a price control period exists.

These points are addressed below.

### 2.3.1. Capacity Commodity split

A second element of the tariff design is the allocation of costs to different aspects of demand. For gas transmission this has focused on the allocation between capacity and commodity charges.

In both jurisdictions, capacity/commodity charges are levied, but at different proportions of cost (Ireland 90/10; Northern Ireland 50:50). This area was reviewed in Northern Ireland and will be changed from October 2008 to 75:25. Table 2.1 provides an overview on the capacity/commodity split in Ireland and Northern Ireland.

**Table 2.1: Capacity and Commodity splits (%)**

| | Ireland | Northern Ireland | Northern Ireland (Oct 2008) |
|---|---|---|---|
| Capacity | 90 | 50 | 75 |
| Commodity | 10 | 50 | 25 |

### 2.3.2. Tariff Smoothing

The final element of the tariff regime is the way in which revenues are recovered within a price control period. Different approaches are adopted in the two jurisdictions:

- in Ireland a smoothed net present value (NPV) approach is used where the total costs and demand over the whole price control period are considered before establishing a price profile for the whole control period

- in Northern Ireland an accounting based approach is used where the revenue requirement for each year of the price control is determined and then that level of revenue is used to set prices for that year.

## 2.4. Summary

In summary, there are quite significant differences between the existing tariff structures in Ireland and Northern Ireland. These are summarised in Table 2.2.

**Table 2.2: Tariff structure differences and commonalities**

| | **Ireland** | **Northern Ireland** |
|---|---|---|
| Capacity/Commodity Split | 90/10 | 50/50 (75/25 from Oct 08) |
| Entry | Separate | Postalised |
| Exit | Postalised | Postalised |
| Rate of Return | 5.2% | SNIP (2.461%) and BGTP (2.387%) mutualised – WACC based on fixed bond payment<br>BGE (NI) 6.19% |
| Depreciation | Straight Line | Cash Flow Methodology |
| Tariffs | Smoothed over 5 years | Set each year independently |
| Capacity Trading | Available | Available |
| Short Term Product | Available | Not Available |
| Interruptible Product | Not Available | Available |
| Inventory Product | Available | Not Available |

**Question**

**1: Have we adequately described the differences / commonalities between the two markets?**

# 3. Assessment Criteria

Any proposed reform of a regulatory regime needs to be assessed to determine whether it is better able to meet the objectives of regulation than the existing approach. To be able to undertake this assessment it is necessary to establish a set of criteria that will provide the base line for comparison. Criteria are likely to arise from:

- the primary legislation establishing the respective Regulatory Authorities;
- Government and wider (such as EU) principles of good regulation – often incorporated into better regulation principles; and
- practical issues relating to the sector and future development.

This Section focuses on the proposed set of criteria informed by the statutory and better regulation criteria but also incorporating practical considerations.[6] These should be placed within the broader context as set out in the MoU and as presented in Section 1.

From a tariff design perspective there are obligations upon the Regulatory Authorities from a European level. For example, Article 3 of Regulation (EC) No 1775/2005[7] ("EC1775") sets out specific guidance in relation to tariffs for access to networks. Following on from EC 1775, European Regulators Group for Electricity and Gas Regulation (ERGEG) produced a Consultation Paper[8] which sets out (as guidance) principles for the development of transmission tariffs. There are however, other issues to be considered such as the size of the combined markets and the impact this may have on the appropriate regime design.

Key considerations are:

- Developing the industry – this incorporates a range of issues including cost orientation, a degree of cost averaging and ensuring financial viability;
- Protecting consumers – this entails ensuring sustainable efficient tariffs and minimum volatility in prices (including the IBP);

[6] Annex 2 provides the relevant sections of the legislation for both the Utility Regulator and CER. It also provides a summary of the better regulation criteria for both countries.

[7] Regulation (EC) No 1775/2005 of the European Parliament and of the Council of 28 September 2005 on conditions for access to the natural gas transmission networks

[8] Principles on Calculating Tariffs for Access to Gas Transmission Networks – An ERGEG Public Consultation Paper, 22nd November 2007.

- Security of supply – which involves ensuring sufficient diversity of supply as well as security of supply; and
- Promotion of competition – at both the wholesale and retail level.

In reality, there is often an overlap between these four broad criteria – for example, elements of the criteria regarding protecting consumers or security of supply are also linked to the development of the gas industry. In section 5 the criteria are kept separate.

## 3.1. Developing the industry

Both Regulatory Authorities see an important role for developing a viable gas industry in their respective jurisdictions. This is explicit for the Utility Regulator where the clause requiring postalisation is basically to support industry development. It is more implicit in Ireland where geographic postalisation within the onshore transmission exit tariff ensures that there is no undue discrimination between different parts of the country.

Other concepts that need to be borne in mind include:

- designing a mechanism that is, as far as possible, cost reflective; and
- ensuring that the investment and consumption signals sent by the tariff are appropriate.

These are important because although development of the gas industry is significant for broader reasons it is also vital that only economic investments are undertaken.

## 3.2. Protecting consumers

Ensuring that prices are as low and stable as possible is key to protecting consumers. Of course, this does not mean that prices should be set below cost recovery, but rather that prices should be as low as possible for an efficient company. This should ensure that the industry is sustainable in the long-term.

Price volatility arising from any tariff regime is also a key consideration for the Regulatory Authorities. Price volatility cannot be looked at in isolation though as there is an inextricable link between prices, revenues and profits and one cannot be altered dramatically without affecting the others. Another key aspect of this is the potential volatility that either jurisdiction may experience in isolation from the other. This would be where the tariffs change considerably in one jurisdiction and they remain the same as before in the other jurisdiction. Further, some

reforms could introduce greater variability in prices within a jurisdiction. While this may better reflect the underlying cost of delivering service (such as to rural rather than urban areas) it can also work against broader criteria of promoting gas development which forms part of the Regulatory Authorities' objectives.

In addition, the potential fluctuation of tariffs from year to year is an issue. In Ireland the revenue requirement is smoothed over 5 years to avoid fluctuations from year to year insofar as possible. In Northern Ireland the revenue requirements are not smoothed and tariffs are set each year based on the revenue requirement for that year.

Overall, a reform would be successful if it keeps the price level at a point where efficient investment in new indigenous production is undertaken while minimising the volatility in the price level (accepting that most end-user price volatility is outside the control of the regulator since it is driven by the volatility in the actual cost of gas) and ensuring that any geographic deviation is minimised.

### 3.2.1. Impact on the marginal cost

Volatility in prices can have a major effect on the marginal cost (the IBP in Ireland) point but this is dependent on the tariff framework adopted. The balancing point is essentially the cost of gas based on the cost of marginal gas delivered[9]. In the present Ireland regime the marginal cost of gas is set by gas entering through Moffat. Therefore any increase in prices and volatility on the ICs would have a considerable effect on the price that customers in Ireland and Northern Ireland pay for gas – this can lead to inefficient investment as discussed in Section 3.3. In a fully postalised regime although there is no formal balancing point the effective balancing point is based on the average entry costs, as is the case in Northern Ireland.

One issue that should be addressed is whether having a formal balancing point as with the IBP is useful. In principle it can facilitate competition – the role of competition is discussed further below.

[9] In Ireland at present, the Balancing Point is a notional point where gas is traded in Ireland. It is essentially gas that is onshore and the buyer pays the onshore tariff to take the gas from the system. The IBP can be reached by delivering gas onshore from either Inch or Moffat. As the Moffat gas is marginal it sets the IBP price which would equal the UK NBP plus UK Transportation charges and the Moffat Entry Tariff.

### 3.2.2. Interaction with the wider energy market

Having successfully established the SEM it is important that the knock-on effects of any gas reform are considered, especially since gas fired generation dominates the generator portfolio (although this may to change as per government renewables policies).

### 3.2.3. Ease of implementation

With the development of any harmonised transmission tariff regime the ease with which it can be implemented should be carefully considered. The postalised tariff regime in Northern Ireland is embedded in primary legislation and any move away from the present regime would require an amendment to the Energy (Northern Ireland) Order 2003. In reality though, there may be some form of legislative change required no matter which regime is employed.

Essentially there would be complexities with adopting either regime. Moving to a fully postalised system would require a complex revenue sharing formula to distribute revenues to the appropriate asset owner. The issue of currency differences in the two jurisdictions must be kept in mind also.

Further, other practical aspects of implementation need to be considered. These include the:

- ability for any negative impact to be addressed – if customers in one jurisdiction suffer from a reform option there will need to be some revenue transfer from the other jurisdiction made available; and
- ability to handle any issues arising from mutualisation – two of the key pipelines in Northern Ireland are mutualised and this places some specific obligations on the regulator and consumers – the ability of any reform to meet those obligations is an issue.

A successful reform would be one that minimises the cost of implementation, or where the benefits far outweigh any increase in the implementation costs.

## 3.3. Security of supply

Security of supply and indigenous gas production are key concerns for the Regulatory Authorities. Any tariff methodology developed must be cognisant of this fact and the impact on indigenous producers and potential investors must be considered. For example, the lack of, or presence of, incentives to develop new indigenous sources are a key aspect of the tariff regime.

Consequently, the impact on tariffs when a new indigenous source comes on stream is a further key consideration for the Regulatory Authorities. This will be of particular relevance once Corrib comes onstream in late 2009 and again potentially in 2012 if Shannon LNG commences operation. When Corrib (and Shannon) starts to flow, utilisation of the ICs can be expected to reduce considerably. This is the underlying driver of price volatility discussed above. Apart from changes to supply, any regime needs to be robust to changes in demand. For example, in the respective jurisdictions government policy concerning renewable based generation has to be a consideration owing to its likely impact on commodity throughput.

From an economic perspective, the key role for tariffs is to send the right signal regarding consumption and investment (both for transmission and production/storage). As such, some response as new indigenous sources come on-stream is important to send signals about the timing of future investment in production. Some reduction in incentive for new investment would be appropriate as new sources come on-stream. This is different to the existing position where the incentive for investment in production actually increases as new sources become available, provided the total indigenous supply does not exceed the local demand.

Knowing the level of signal necessary for new investment, especially to meet diversity and security of supply concerns is key to designing a sustainable tariff methodology. If it is not possible to determine this in an appropriate way for assessing alternative tariff structures it may be better to consider alternative ways of encouraging affordable diversity and security of supply.

## 3.4. Promotion of competition

Finally, any reform should be one that promotes, or facilitates, competition. The MoU clearly states as an objective of the Regulatory Authorities to ensure that gas is bought and sold in competitive markets at the wholesale and retail levels and to encourage a “single market” approach. A key criterion for success will be the creation of a market with sufficient critical mass to sustain competition (limited by the size of the combined market). A further key consideration of any tariff structure is that it maintains a strong link to the NBP in GB which is the output of one of the most competitive gas markets in Europe. Competition should be encouraged where it is cost effective and likely to lead to a better outcome for consumers.

**Questions**

**2: Do you feel that all the relevant criteria have been covered in this document and are there other criteria you feel should be included?**

**3: Do you have a view in relation to the priority of the criteria and whether some criteria should be considered more important than others.**

# 4. Reform Options

This section provides a summary of the possible reform options to be considered in the consultation.

## 4.1. Postalisation

One possible reform option would be to move the whole of the island onto the same basis as Northern Ireland, i.e. fully postalised tariffs. This would entail a combined entry and exit tariff covering the whole island and average cost pricing.

## 4.2. Entry

With respect to entry, there are a range of possible options including:

- Single entry point – i.e. amalgamate all the existing and future entry points into a single one;
- Two entry points – i.e. a combined IC entry point (Moffat) and a separate combined entry point for all other existing and future controls, i.e. Inch, Corrib, Shannon LNG etc would all be treated as part of the same "other" entry point;
- Single IC entry point and separate controls for all other entry points – i.e. amalgamate SNIP and the two southern ICs into a single Moffat entry point but leave all other existing and future entry points separate, i.e. Inch, Corrib, Shannon LNG etc.;
- Existing treatment of the two ICs but combined treatment of all other entry points – i.e. amalgamate Corrib, Inch, Shannon etc but leave the existing separate treatment of SNIP and the ICs;
- Separate entry points – i.e. no change from the existing situation of three existing entry points, SNIP, the southern ICs and Inch, and then each new source of gas having a separate entry point, i.e. Corrib, Shannon LNG etc.; and
- Further separation – i.e. split the existing southern IC into two separate controls, one for IC1 and one for IC2. All other entry points would be left unchanged.

The various entry and exit options are summarised in table 4.1.

## 4.3. Exit

For exit there are a small number of possibilities:

- Single exit point – i.e. amalgamation of the Ireland and Northern Ireland on-shore systems into a single system;
- Two exit points – i.e. an Ireland on-shore and a Northern Ireland on-shore; and
- Multiple exit points – i.e. break the existing onshore system into a greater number of systems, like the Local Distribution Zones (LDZs) in GB or indeed point to point exit.

For example, this last option could allow specific assets like the South-North pipeline to be treated as two separate zones, one in Ireland and one in Northern Ireland.

**Table 4.1: Summary of entry-exit reform options**

| **Entry** | **Exit** |
|---|---|
| Postalised system | |
| Single | Single combined on-shore system |
| Combined Moffat and others separate | Existing approach |
| Combined Moffat and combined others | Multiple (more than two) exit points |
| Existing treatment of SNIP and IC but combined other entry points | |
| Further separation of the ICs into two individual entry points | |

When looking at the available options in terms of regime design and looking at postalised versus entry/exit it is useful to refer to other European regions and the regimes they employ. Table 4.2 below lists the transmission tariff methodology employed in a number of European jurisdictions.

**Table 4.2: Regime design in other European countries[10].**

| Entry – Exit | Postalised |
|---|---|
| France, Germany, Netherlands, Italy, Great Britain, Belgium, Ireland. | Austria, Denmark, Spain, Luxembourg, Sweden, Poland, Lithuania, Slovakia, Slovenia, Northern Ireland. |

[10] Sources: DGTREN Working Paper, Third Benchmarking Report on the implementation of the internal electricity and gas market (2004). Gas Transport Services: Arthur D Little; West European Gas Transmission Comparisons (2005).

## 4.4. Mitigating the effect of declining interconnector utilisation

The paper also deals with issues arising from the effect of the expected decline in utilisation of the ICs on the marginal cost pricing system under an entry/exit regime. This issue is unrelated to CAG and not a consequence of CAG and would impact on the IBP even if CAG were not to take place. However we are dealing with this issue at this time as some of the proposed tariff methodologies interact significantly with this issue.

Under an entry/exit regime the marginal source of gas sets the price of gas at the IBP. Given the demand for gas in Ireland, it is assumed that the ICs are the source of marginal gas, consequently the cost of gas at the IBP can be viewed simply as GB gas price (NBP) plus IC transmission charge. Thus the price of gas in Ireland (IBP) is higher than the gas price in GB. This acts as an incentive to producers of gas in Ireland (e.g. from Ireland's offshore fields or LNG). However as IC utilisation declines, the IC transmission charge rises and IBP rises. Depending on the tariff methodology chosen (i.e. if an entry / exit regime is chosen) this rise could become very significant unless mitigated by some other mechanism. The mechanisms considered focus on reducing the rise in the IC transmission charge and are set out below:

- Reducing the annual revenue requirement of the ICs by;
    - Establishing a PSO levy to defray some of the costs
    - Buying down some of the costs through changing the Regulatory Asset Base (RAB) by moving or suspending some of the asset value during the trough in consumption
    - Cutting the allowed rate of return.

- Reducing the effect of the decline in utilisation by:
    - Reprofiling (averaging out the trough in consumption)
    - Setting a minimum booking level (filling in the trough)
    - Reducing the depreciation level during the trough in consumption

### 4.4.1. Establishing a Public Service Obligation (PSO) levy

The establishment of a PSO levy could be used as a means of collecting revenue from all network users to defray some of the cost of the ICs. The establishment of a PSO is catered for at European level through Directive 2003/55/EC. It is also allowed for in Ireland through SI 452 of 2004. There are PSO mechanisms currently employed by both jurisdictions for electricity

### 4.4.2. Changing the RAB by moving costs

This involves moving some of the cost of the ICs. What needs to be considered is:

1. What costs might be moved?
2. Where would they be moved to?

In terms of the options for what costs might be moved the obvious candidates are:

- part of the southern ICs; and
- part of each entry point reflecting existing price differentials.

The most likely destination for any costs being moved is the onshore system since it has the lowest price elasticity of demand – effectively using Ramsey pricing principles.

### 4.4.3. Cutting the rate of return

This could involve a reduction in the allowed cost of capital, either through a formal option like mutualisation, a more informal option of guarantees or direct government debt being used to shift the cost towards the risk-free rate[11].

### 4.4.4. Changing the RAB by suspending assets

The relevant asset could be "stranded" and then remunerated through a charging mechanism. Alternatively, an asset could be "suspended" whereby it is taken out of the revenue requirement for a period of time but re-introduced when utilisation of the asset is at a level where prices would not rise above an "acceptable" level.

### 4.4.5. Reprofiling (averaging out the trough in consumption)

Reprofiling of costs over time through longer price control periods, where the average utilisation is used to set the tariff over the period would limit the rise in price for the IC transmission charge

### 4.4.6. Setting a minimum booking level (filling in the trough)

This has the straightforward effect of maintaining the bookings at a level where prices would not rise above an "acceptable" level. This could be then remunerated through a charging mechanism until utilisation recovered.

[11] Obviously there would be further actions needed to make full mutualisation a reality. However, these are actions that should be possible and so, in our view, do not constrain the viability of this option.

#### 4.4.7. Reducing the depreciation level during the trough in consumption

Reducing the depreciation charge during the trough in consumption should leave the asset fully remunerated over time but lowers the remuneration during the relevant period (as is currently being used for IC2)

#### 4.4.8. Summary

Consequently there are multiple options within this broad category. Further, these options are not necessarily mutually exclusive from the options discussed in Sections 4.2 and 4.3.

It should be noted that these reforms are aimed at changing the existing cost based system. An alternative would be to consider shifting the basis for charging away from a cost base system towards an auction based system – as used in GB for entry tariffs. It is possible that insufficient revenues would be recovered to meet the costs and consequently some additional revenue would have to be recovered from elsewhere – this could be from the onshore system or alternatively through a charging mechanism. In GB at present an auction is held and if the auction is expected to lead to under-recovery then a commodity charge at entry is introduced.

### 4.5. Tariff structure

As noted in Section 2, there are two issues within the tariff structure that need to be considered. These issues are considered in conjunction with options discussed in Sections 4.1 to 4.3.

#### 4.5.1. Capacity and Commodity charges

There are two sets of options to consider here:

- whether there should there be common allocations to capacity and commodity charges in Ireland and Northern Ireland? and
- If there were to be common allocations at what level would they be set?

As shown in Section 2, Northern Ireland's allocation between capacity and commodity will be 75:25 from October 2008. Ireland operates a 90:10 allocation.

When considering this issue it is important to bear in mind the following:

- the underlying cost nature of the businesses – on a cost reflective basis this will vary between jurisdictions; and

- the fact that utilisation is likely to change over time as the proportion of renewables in the generation portfolio changes and less volume of gas is needed over a year although a similar level of peak capacity may be needed. This shift in the relative importance of capacity and commodity could also have an important effect on some of the assessment criteria set out in Section 3.

It seems logical to harmonise the proportions allocated between capacity and commodity in the two jurisdictions, not least due to the gas market interaction with the SEM. Ideally, from an economic point of view, capacity charges would reflect the proportion of costs that are fixed in the network since this helps ensure the right signals for investment and utilisation of the assets. Against this must be considered the issue of the likely future demand for gas. As renewable energy accounts for an increasingly significant proportion of the generation across Ireland, it is likely that overall gas throughput over the year will drop, although demand on the peak day is unlikely to be affected, since the peak day is defined as one where there is no wind generation available. In essence, the shift to greater wind generation may lead to lower overall utilisation (commodity) of the network but unchanged capacity requirements. This may be an important consideration in any decision about future capacity and commodity charges.

### 4.5.2. Tariff smoothing

This refers to the approach to setting tariffs within a price control period and whether a common approach should be established. As noted in Section 2, a smoothed approach is adopted in Ireland while a more annual accounting approach is adopted in Northern Ireland.

While the two approaches will give the same NPV of revenues over the life of the price control period the profile of prices may be quite different. In Northern Ireland, given the almost full utilisation of the SNIP it is likely that the annual accounting prices and the smoothed NPV prices could be quite similar. However, in a system that is growing, or where new indigenous sources of gas are found, and the consequent under-utilisation of some assets is possible then quite different price profiles could be found – this is the likely situation in Ireland.[12]

Potentially, this smoothing principle could also be extended to consider smoothing across price control periods as a way of mitigating some of the more marked implications for tariffs for all customers arising from marginal cost pricing. This also has implications for some of the other

[12] There is a potential constraint to the opportunity to alter the system in Northern Ireland since as part of the mutualisation process there is a requirement for the companies to be able to meet debt service obligations in any given year.

assessment criteria. The level of overall tariff smoothing required will reduce if the volatility of the demand on the ICs is removed. It is important to consider the advantages of the introduction of smoothing against its overall impact if the final benefit to consumers is relatively small.

### 4.5.3. Non-annual gas capacity products

The non annual gas product offerings in Ireland and Northern Ireland are different at present as set out back in Table 2.2. There are some commonalities though. Much of the requirements for flexibility in products are driven at an EU level, principally through Regulation EC 1775. The objective of Regulation EC1775 is to “tackle remaining barriers to the completion of the internal market in particular regarding the trade of gas”. It relates specifically to the rules regarding third party access services, principles of capacity allocation mechanisms, congestion management procedures and transparency requirements. It aims to provide a guarantee of equal market access conditions for all parties, from any Member State, seeking entry into a market in another Member State. The intention is to set harmonised principles for third party access services, capacity allocation mechanisms, congestion management and transparency requirements.

To date, the implementation of Regulation EC 1775 is at different stages in Ireland and Northern Ireland with regard to non annual gas products. As part of this work the Regulatory Authorities express a desire to harmonise such products. In reality though, this will be driven somewhat by the Operations Workstream as these products generally need to be systemised and detailed in the relevant Network Codes/Codes of Operation. Annex 3 sets out the principles of the non annual gas capacity products currently developed in Ireland and Northern Ireland. The main products that may be developed (and harmonised) as part of CAG are set out below. There may be other products that some participants would like to see available also (Not all of these products are currently available in either jurisdiction).

- Short-term Products
- Inventory Products
- Interruptible Products
- Storage Tariffs
- Reverse Flow / Backhaul Tariffs

## 4.6. Determining revenue requirement through auctions

It was noted earlier that GB has shifted to an auction system for setting capacity charges at entry points. This is an alternative to the existing approach that could be considered for the combined systems and which might address some of the utilisation problems. It would still be necessary to determine the required revenue as per the existing approach since it is necessary to establish whether the auctions are able to raise sufficient revenue to cover costs, but the actual price per MWh/peak day would be set by the demand to use the entry point.

## 4.7. Summary

This Section has set out the key possible reforms under consideration. When analysing these options in Section 5 of this paper, a key concern will always be whether any adverse impacts of an option can be overcome in a relatively straight-forward manner.

**Questions**

**4: Do you feel we have adequately represented the appropriate reform options at Entry and Exit? What further reform options do you feel warrant further investigation?**

**5: In relation to mitigating the effect of declining interconnector utilisation, have all the viable options been set out? What option do you feel is missing? What level of price incentive, if any, do you feel is an adequate signal to incentivise indigenous gas production/storage?**

**6: Do you think we should harmonise the capacity/commodity split?**

**7: Do you think we should aim to harmonise non annual gas capacity products? What products do you feel should be available?**

# 5. Assessment

Having set out the reform options and criteria against which they should be considered, it is now possible to provide an initial assessment of how each of the options meets the criteria. The results of the financial modelling explained in Annex 1 will also inform these assessments. The base line results for capacity tariffs are shown in Table 5.1 below – these are then measured against when each option is being considered. Only capacity tariffs are shown since they represent 90% and 75% of the revenue requirement respectively in Ireland and Northern Ireland. The values in Table 5.1 above are indicative and based on existing best available assumptions with respect to supply (including the size and timing of Corrib and Shannon LNG becoming available), demand (capacity bookings and commodity flows) and the regulatory determination of revenue requirements (depreciation, asset valuation, rate of return, etc) which are explained in more detail in Annex 1. It is assumed that the relevant revenue is recovered over each price control period.

**Table 5.1: Base line capacity tariffs (indicative) for 2008 to 2020 (€/MWh/peak day)**

| **Control** | **Existing Capacity-Commodity split** | | | | **80:20 split** |
|---|---|---|---|---|---|
| | **Existing (if applicable)** | **Average** | **Minimum** | **Maximum** | **Average** |
| Corrib | | 352.83 | 131.42 | 1,703.71 | 313.63 |
| ICs | 308.54 | 1,233.95 | 297.13 | 2,726.89 | 1,010.66 |
| Inch | 62.32 | 83.90 | 62.32 | 96.32 | 74.58 |
| SLNG | | 13.80 | 12.63 | 14.79 | 12.27 |
| Onshore South | | 399.34 | 378.52 | 450.17 | 354.97 |
| NI Postalised | 381.44 | 344.31 | 330.74 | 389.26 | 367.26 |
| *Of which:* | | | | | |
| SNIP | | 174.76 | 164.38 | 184.99 | 186.41 |
| Onshore North | | 223.33 | 217.07 | 226.15 | 238.22 |

In Table 5.1 above the relevant capacity commodity splits (75:25 for NI) are used in the first column entitled Existing (if applicable).

Figure 5.1 provides the same information graphically. As can be seen, the spike in IC tariffs to over €2,000 MWh/peak day occurs when both Corrib and Shannon are operational. The reason

for this is that the capacity utilisation of the ICs is forecast to drop significantly, even as far as zero in one year, before the utilisation starts to recover.

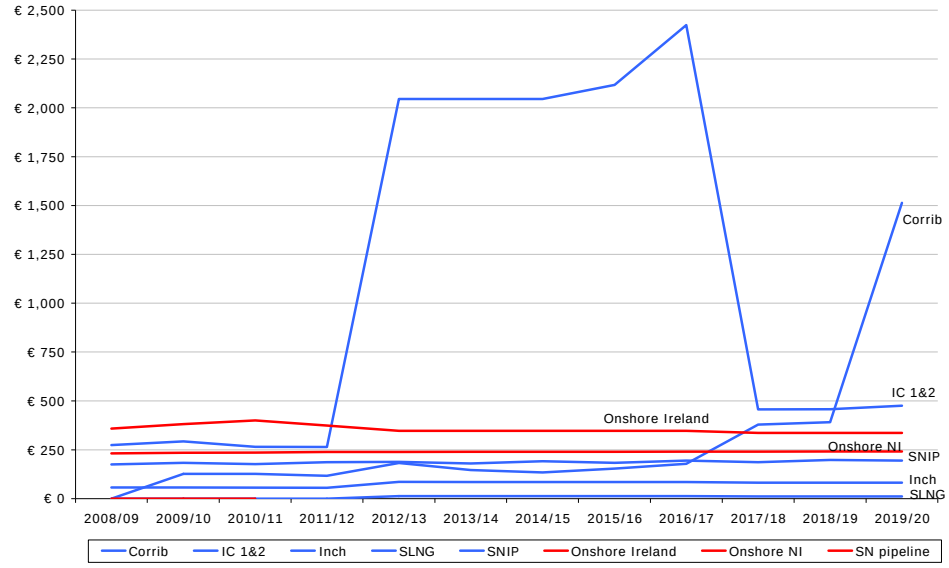



**Figure 5.1: Base line capacity tariffs (indicative) for 2008 to 2020 (€/MWh/peak day)**

Note: as per table 5.1, these numbers are indicative and based on existing assumptions underlying revenue calculations and an 80:20 capacity commodity split.

In reality, the profile of tariffs presented is one that would never be allowed to occur. They do, however, illustrate quite starkly the impact of Ireland's existing regime and the potentially perverse incentives for developing new production that exist.

The modelling carried out as part of this work is based on a series of assumptions about the operation of the network, the phasing of revenue requirements and impacts of additional transmission pipelines. No impact from Larne Storage has been modelled to date but it could be expected to increase tariffs further on the IC. A scenario incorporating Larne will be available at the time of the industry workshop which will be held during the consultation period.

## 5.1. Postalisation

The first reform option to consider is that of postalisation. Clearly from a consumer viewpoint, at least in the short- to medium-term, there are significant benefits from postalisation – especially in Ireland. Postalisation leads to:

- a simplified tariff structure;
- assured revenue recovery and the Northern Ireland annual approach; and

- lower and less volatile prices for consumers.

Against this must be considered the impact on investment/consumption signals and overall security of supply. There would also be some implementation issues associated with establishing a postalised tariff. One such issue would be where a fully postalised tariff regime (two jurisdictions combined) is employed and the tariff is higher than the tariff that would otherwise be faced in Northern Ireland. In this scenario some form of revenue transfer would need to be developed. Also there could potentially be currency risk issues between the two jurisdictions which would need to be addressed. However, it should be possible to establish a system able to address this; similar issues have been addressed within the SEM.

Figure 5.2 below illustrates the fact that postalisation would smooth out some of the variability. A postalised tariff (Ireland and Northern Ireland), under these assumptions, would range between €400 and €650 MWh/peak day. While an Ireland only postalised tariff would range from €450 to €950 MWh/peak day. The Northern Ireland postalised tariff ranges around €350 MWh/peak day. In reality some of the variability would be smoothed out through within price control period smoothing as part of any regulatory determination. This would involve a consideration of planned utilisation and commodity flows when determining what revenue is recovered in each year within a framework of recovering the whole required revenue for the five year price control period. This is the approach currently employed in Ireland.

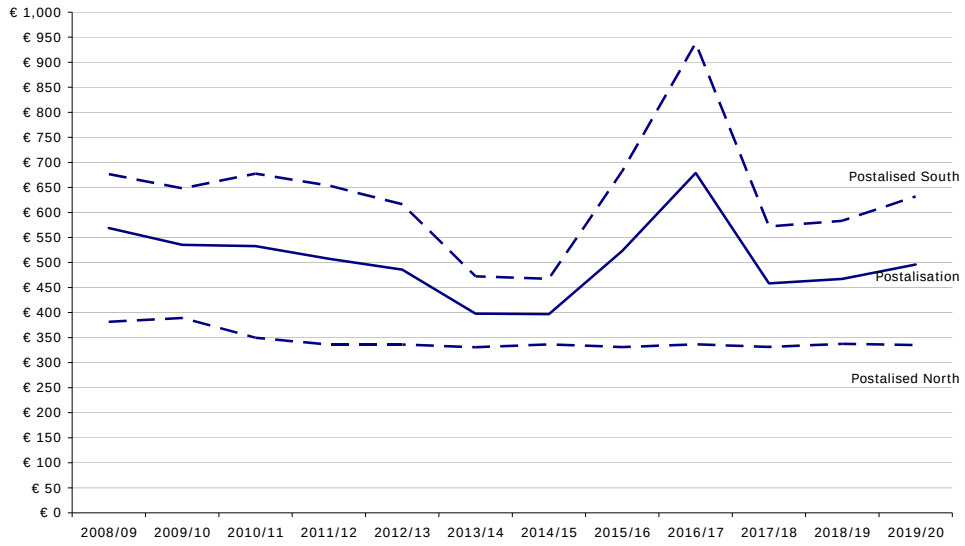



**Figure 5.2: Postalised capacity tariffs (indicative) for 2008 to 2020 (€/MWh/peak day)**

Table 5.2 provides a summary of the assessment of the option against each of the criteria.

**Table 5.2: Assessment of Postalisation**

| Criteria | Assessment | Comment |
|---|---|---|
| Development of the gas industry | Significant | Postalisation through an average cost approach creates a significant incentive for the development of the gas industry. Since consumers pay the average cost of delivered gas (meaning that tariffs are cost based) this may actually create inefficient demand since the cost of marginal consumption is not faced by the marginal consumer.<br>Financial viability would be ensured through the average cost tariffs. |
| Protection of consumers | Significant | Postalisation would produce the lowest tariffs for consumers and the least volatile tariffs. The impact of this is shown in Figure 2.2.<br>Although there would clearly be implementation issues to address they are ones that should be manageable. There is a potential to minimise legislative change. A new mechanism for encouraging security of supply may be needed (possibly based around bidding for the least cost option for improving security of supply) and some form of revenue transfer mechanism would be needed if average prices to customers in one jurisdictions increase. There would also be an issue around designing a mechanism to handle the two currencies within a postalised system. Obligations under mutualisation in Northern Ireland would also need to be considered. |
| Security of supply | Potentially poor | Although as new sources of indigenous gas become available prices will increase under postalisation, the impact will be smaller than under entry-exit since the cost is being shared across more customers and is not dependent on the impact on the demand for the marginal source of gas. Consequently the tariff regime would remove the whole incentive that is currently available to producers from the marginal source of gas pricing used in Ireland. Whether this would persuade some new sources of gas which would offer diversity of supply to not develop is not clear. This is most likely to be of most importance to LNG and storage services. |

| | | |
|---|---|---|
| Promotion of competition | Potentially poor | The ability to exploit differences in transmission entry point costs will be lost. A more competitive market would potentially be one where customers were able to negotiate some of the benefit currently accruing to producers. However, given the size of the market and the limited sources of supply it is not clear whether much competition is likely to develop in the short- to medium-term. |

As set out above, the move to a fully postalised regime could act as a disincentive for existing and potential producers which may give rise to security of supply concerns. An alternative way of delivering security and diversity of supply could be developed. This could take the form of an auction where market participants can demonstrate willingness to pay and provide security and diversity of supply.

**Questions**

**8: Do you feel that we have adequately described Postalisation under the selected criteria?**

**9: Do you feel that Postalisation is a viable option for the harmonisation of transmission tariffs in the two jurisdictions?**

**10: How should we deal with revenue transfer between the two jurisdictions under postalisation?**

**11: How should we deal with currency risk arising from the Postalisation option?**

## 5.2. Entry Options

Within the entry reforms there are four viable options[13]:

- a single entry point (effectively equivalent to postalisation if combined with a single exit option but worth considering on its own if multiple exit options are considered);[14]
- a single Moffat entry point (combining SNIP and the southern ICs) with all other entry points combined;
- a single Moffat entry point (combining SNIP and the southern ICs) with all other entry points treated separately; and
- the existing position of separate entry points.

If the first option is excluded, since it has effectively been dealt with earlier under postalisation, the other two options involving change offer ways of providing some benefits to customers – lower prices (for Ireland) since costs are spread over a larger user base since a greater capacity utilisation and commodity flow is available and more stable prices since changes in demand are proportionately smaller than under the existing position (separate entry points). Some of the options also limit the implementation issues associated with having two currencies. The options also have negative effects, for example, the incentive for existing and future indigenous producers will drop since the balancing point will be less affected by the source of flows.

Further, introducing entry-exit pricing in Northern Ireland would lead to an increase in prices for customers (although the exact degree depends on the form of entry regime). Appropriate mitigation of this would be necessary and consequently a mechanism would need to be established.[15] Although designing a mechanism to address this should be possible it is likely to entail significant ongoing implementation issues.

Table 5.3 summarises the assessment of the various entry options while Figure 5.3 illustrates the impact of the options. As would be expected, combining the various IC entry points

[13] Although other options were identified in section 4.2 they either involve options that will not change the price of the marginal source of gas, so having no end-user impact, or would exacerbate the existing problems with the Ireland entry-exit regime, such as splitting the ICs into IC1 and IC2.

[14] There is a small difference between a single entry and single exit point system and postalisation since the two may be calculated against different volume values.

[15] The degree of mitigation would obviously depend on what the real counter-factual would be. This is likely to involve increasing costs either as more gas flows through the IC and the South-North pipeline or the costs of reinforcing SNIP.

significantly reduces the tariff and its volatility. This is also shown in Table 5.4 below. As expected there is a very significant drop in the capacity tariff.

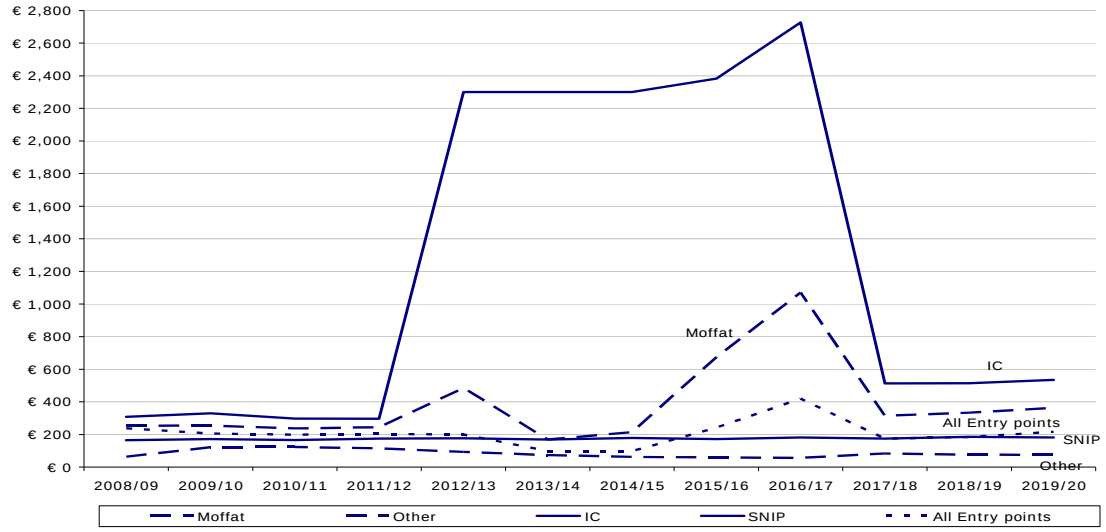



**Figure 5.3: Entry capacity tariffs (indicative) for 2008 to 2020 (€/MWh/peak day)**

Note**:** Other is a combined entry point for Inch, Corrib and Shannon

This diagram shows that, compared to the existing forecast tariffs:

- the Moffat and All-entry options would produce an entry tariff that is increasingly stable over the period, and even some of the remaining variability could be removed through within price control period smoothing. However, these are more expensive and volatile options than the existing SNIP; and
- combining the other entry points (Inch, Corrib and Shannon) into a single entry point would produce a stable and low cost entry point. If this is compared to the existing and forecast tariffs as per Figure 5.1 it can be seen that the gradually reducing capacity of Corrib and the consequent increasing price (if so priced) is mitigated through the addition of Shannon and Inch.

**Table 5.3: Comparative entry capacity tariffs (indicative) for 2008 to 2020 (€/MWh/day)**

| Control | Average | Minimum | Maximum |
|---|---|---|---|
| Southern ICs | 1,233.9 | 297.1 | 2,726.9 |
| SNIP | 174.8 | 164.4 | 185.0 |
| Moffat | 384.7 | 168.9 | 1,070.9 |
| Others (Combined) | 83.9 | 56.9 | 123.2 |
| Single Entry Point | 206.5 | 419.4 | 97.4 |

**Table 5.4: Assessment of entry options**

| Criteria | Single entry point | Two (Moffat and combined other) | Combined Moffat and separate others | Separate |
|---|---|---|---|---|
| Development of the gas industry | Mixed. Average pricing should at least sustain gas demand growth. The price differential incentive for indigenous producers is lost. | Mixed. Gas demand growth should be sustained due to some cost averaging There is an averaged price differential incentive for all indigenous producers. | Mixed. Gas demand growth should be sustained due to cost averaging at Moffat. There is more of a price differential incentive for indigenous than the previous options but less than with separate SNIP and IC. | Mixed. Overall gas demand growth may decrease due to potential rise in IBP. There may be a significant price differential incentive for indigenous production. |
| Protection of consumers | Good. Price levels and variability will be kept low since this is effectively postalisation of entry. | Good. Price levels and variability will be kept low – although not as low as a single entry point. | Good. Price levels and variability will be kept low – although not as low as a single entry point. | Poor. Price levels will be higher than in the other cases and more volatile (although this can to an extent to addressed through other means – see section 5.4) |
| Security of supply | Potentially poor. The benefit currently earned by producers would be lost. If this is needed to encourage diversity and security of supply then there would be a negative impact. | Potentially poor. The benefit currently earned by producers would be reduced. If an incentive is needed to encourage diversity and security of supply and what is available under this approach was not sufficient, then there would be a negative | Potentially poor. The benefit currently earned by producers would be reduced but by not as much as under the two entry point option. If an incentive is needed to encourage diversity and security of supply and what is available under this approach was not sufficient, then there | Good. The existing benefit would be continued, although the precise amount would depend on whether other actions are taken. There is clearly the risk that too great an incentive is on offer and that customers are paying prices that are too high given their needs for security and diversity of |

| Criteria | Single entry point | Two (Moffat and combined other) | Combined Moffat and separate others | Separate |
|---|---|---|---|---|
| | | impact. | would be a negative impact. | supply. |
| Promotion of competition | Potentially poor. Competition to beat the IBP, if it could develop, would not develop under this option. | Potentially poor. The degree of benefit available from beating the IBP is limited and so this may not encourage competition, were it possible for competition to develop. | Potentially poor. The degree of benefit available from beating the IBP is limited (although greater than under the two entry point option) and so this may not encourage competition, were it possible for competition to develop. | Good. If competition is able to develop on the island then this option leaves the largest benefit available for producers to compete against each other when trying to win customers. |

**Questions**

**12: Do you feel that we have adequately described the entry options under the selected criteria?**

**13: How should we deal with revenue transfer between the two jurisdictions under the relevant options?**

**14: How should we deal with currency risk arising from the above options?**

## 5.3. Exit options

As noted previously, there are basically three exit options:

- the existing approach – effectively two exit points, one in Ireland and one in Northern Ireland;
- a single exit point for the two jurisdictions; and
- multiple exit points – based on some form of local distribution zone or point to point exit.

Each of the approaches has benefits associated with it. The existing approach allows differences in cost to be reflected (table 5.1 illustrated the degree of difference in cost) and also provides a route by which revenues could be transferred between jurisdictions, were an entry-exit system adopted. The implicit postalisation within jurisdiction ensures that tariffs are smoothed.

A single exit point would smooth prices even further and make them more stable by utilising an even larger demand base. It would also simplify any issues that might arise with respect to new customers in Ireland connecting to the South-North pipeline.[16] It would lose the advantages identified above for two exit points in terms of cost reflectivity and a possible route for revenue transfers. Further, a single exit point would introduce the need for a currency adjustment along the same lines as the combined Moffat entry point.

Multiple exit points has the important impact of allowing a more cost reflective system to be put in place, although how meaningful that is in an island the size of Ireland and with the connected load that it has is not clear. Further, such a system would increase the administrative load and would also potentially deter customers in rural areas – this would be a problem in both jurisdictions since roll-out of the network has been predicated on within jurisdiction postalised tariffs. Customers connecting off the Bellanaboy (Corrib)

[16] Depending on the final choice of tariff methodology there may need to be a system of transfer payments to allow customers on the South-North pipeline in the segment in Ireland to pay tariffs to the Ireland system operator who then remits fees to the Northern Ireland operator of the South-North pipeline. Some of the possible options for this include paying the Ireland onshore tariff and then remitting an agreed tariff to Northern Ireland.

pipeline would find the economics of connection had changed significantly if they had to pay a Bellanaboy exit charge rather than the existing onshore charge.[17]

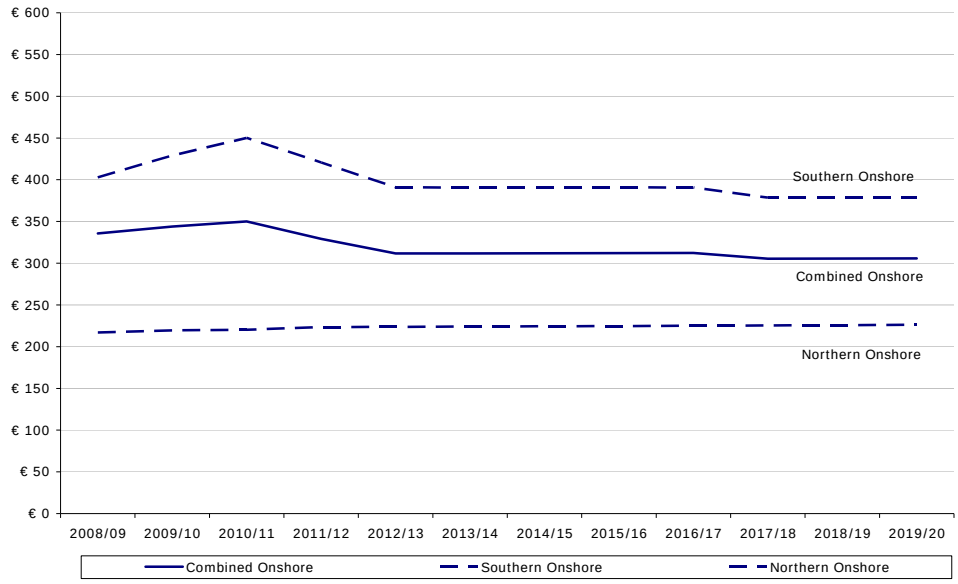



**Figure 5.4: Exit capacity tariffs (indicative) for 2008 to 2020 (€/MWh/day)**

Unsurprisingly, the figure shows that the already stable exit tariffs would be still stable if combined into a single on-shore system.

The assessment in Figure 5.4 is summarised in table 5.5.

**Table 5.5: Comparative exit capacity tariffs (indicative) for 2008 to 2020 (€/MWh/day)**

| Control | Average | Minimum | Maximum |
|---|---|---|---|
| Southern | 399.3 | 378.5 | 450.2 |
| Northern | 228.7 | 217.1 | 234.6 |
| Combined | 319.6 | 305.3 | 350.0 |

[17] We have not modelled the impact of multiple exit zones since insufficient data is available to readily estimate such tariffs. However, the comparison of the Ireland and Northern Ireland exit zones in part illustrates what would happen. The Ireland exit zone is more geographically spread and combines different levels of load when compared to the Northern Ireland exit zone. This, in part, explains the significant tariff differential between the two zones where Ireland is about 80% more expensive than the Northern Ireland.

**Table 5.6: Assessment of exit options**

| Criteria | Single | Two (north and south) | More than two |
|---|---|---|---|
| Development of the gas market | Good. This maximises geographic averaging and so is likely to lead to the strongest demand growth. Is still cost based and should provide financial viability. | Good. The existing situation provides a strong degree of geographic averaging (within jurisdiction) and is cost reflective. Provides financial viability. | Mixed. Is more cost reflective but achieves this at the loss of a degree of geographic averaging – this may damage demand growth especially in more remote areas. Should ensure financial viability. |
| Protection of consumers | Good. Prices are kept as low as possible, across the whole island, and volatility should be minimised. There may be some implementation issues linked to the common currency that would be needed. Revenue transfer between jurisdictions arising from joining the two existing systems would have to be considered. | Good. Prices are kept as low as possible within each jurisdiction and volatility should be kept low. | Poor. Although prices for some customers are kept low, for others prices would increase. Further, variability may become greater since changes in demand within the smaller region would have an impact on the price level. There may be a need for additional rules to ensure financial viability. |
| Security of supply | No real impact – although it could negatively affect the viability of the storage options. | No real impact. | No real impact – although it might positively affect the viability of the storage options. |
| Promotion of competition | Uncertain. By creating a level playing field it might make more competition possible? | Uncertain. | Uncertain. Cost reflectivity could encourage greater competition? |

**Questions**

**15: Do you feel that we have adequately described the exit options under the selected criteria?**

**16: How should we deal with revenue transfer between the two jurisdictions under the single exit option?**

**17: How should we deal with currency risk arising under the existing exit option?**

## 5.4. Mitigating the effect of declining Interconnector utilisation

The paper also deals with issues arising from the effect of the expected decline in utilisation of the ICs on the marginal cost pricing system under an entry/exit regime. This issue is unrelated to CAG and not a consequence of CAG and would impact on the IBP even if CAG were not to take place. However we are dealing with this issue at this time as some of the proposed tariff methodologies interact significantly with this issue. Depending on the tariff methodology chosen (i.e. if an entry / exit regime is chosen) this rise could become very significant unless mitigated by some other mechanism. The mechanisms considered focus on reducing the rise in the IC transmission charge as below:

1. Reducing the annual revenue requirement of the ICs by:
    - Establishing a PSO levy to defray some of the costs[18]
    - Buying down some of the costs through changing the Regulatory Asset Base (RAB) by moving or suspending some of the asset value during the trough in consumption
    - Cutting the allowed rate of return.
2. Reducing the effect of the decline in utilisation by:
    - Reprofiling (averaging out the trough in consumption)
    - Setting a minimum booking level (filling in the trough)
    - Reducing the depreciation level during the trough in consumption

Overall, each of these options has the benefit of reducing the costs paid by customers but this comes with several disadvantages:

- administrative burden – for example, mutualisation involves significant upfront cost in terms of setting up the new corporate governance structures etc;
- transmission investment signals – low guaranteed costs of capital for existing assets may encourage inefficient investment if it is applied to new assets, this could exacerbate long-term problems This could be overcome by either making new investment meet a “private” cost of capital hurdle or placing a stronger requirement for Regulatory/Government approval;

[18] Options for the way that the PSO would be levied include: (i) placing the cost on the on-shore transmission system and (ii) levying a charge per kWh at the distribution level. This would minimise the distortionary impact on gas demand.

- impact on indigenous producers – anything that reduces the cost of the marginal entry point will clearly reduce the IBP and consequently revenues received by producers; and
- concerns about revenue recovery – some of the options, long reprofiling or asset suspension could create concerns about investment being remunerated and consequently actually increase the cost of capital for new investment.

The assessment of the options is provided in Table 5.8. There is a further concern that very significant cost reductions have to be made, possibly greater than those available, for a noticeable impact on costs to occur. For example, reducing the IC asset value by €300m (equivalent to the remaining book value of IC2), or halving the existing 5.2% cost of capital, reduces the average capacity charge by about 20%. While this is a significant impact and should not be ruled out, it does require a significant cost to be removed. Reducing the allowed cost of capital as far as 2.6% is feasible but it will depend on the risk-free rate at the time of financing and the duration of the finance. In theory it could be made to approach the government risk-free rate but even large guaranteed companies like Network Rail in the UK pay a small premium over government borrowing rates (about 20 basis points, i.e. 0.2%).

There has to be a concern that the ability to reduce the costs in a sufficiently meaningful way may not be possible, especially since the volatility in prices would still exist. As such, any cost reduction action would probably need to be undertaken in conjunction with a more fundamental tariff methodology reform.

Another factor that needs to be considered in the assessment is the ability to address the underlying issue. Ireland potentially faces two different impacts in the foreseeable future:

- a trough in IC utilisation created by the introduction of Corrib (high initial flows that tail off – so IC utilisation drops and then recovers); and
- a shift in demand created by the introduction of Shannon LNG (high flows that displace IC utilisation and do not tail off, IC only recovers inasmuch as new demand starts to replace demand lost to Shannon).

Asset suspension might be a viable answer to a trough since there is expected to be a time in the foreseeable future when utilisation recovers but it is unlikely to be of use when dealing with a shift in demand since there is no point in the foreseeable future when demand will sufficiently recover to make taking the asset out of suspension viable.

Of the approaches considered, reprofiling (revenues and depreciation) and asset suspension should be considered for troughs in demand but not shifts. Asset write-offs and other reductions

in financing costs as well as guaranteed capacity bookings can be used for both troughs and shifts, although are probably better suited to the latter.

In relation to the final option namely ensuring a minimum level of capacity booking on the IC, we consider three scenarios, where there are mandatory capacity bookings of 80GWh, 100GWh and 120GWh respectively. There are obvious issues that would need to be addressed, such as who books and pays for the guaranteed capacity. Table 5.7 illustrates the impacts on revenues and prices. As can be seen, and as would be expected, the higher the minimum booking the greater the saving for customers. In terms of net benefit, assuming customers pay the costs associated with this minimum booking, the largest savings are seen keeping the minimum booking at 120 GWh.

**Table 5.7: Impact of different guaranteed minimum capacity bookings**

| Option | Average price (€/MWh peak day) | Total savings over 10 years (€m) | Cost of minimum bookings over 10yrs (€m) |
|---|---|---|---|
| Do nothing approach (Separate entry points) | 1,233.95 | - | - |
| Minimum 80 GWh | 605.86 | 2,612 | 228 |
| Minimum 100 GWh | 518.49 | 2,193 | 266 |
| Minimum 120 GWh | 454.38 | 1,890 | 298 |

*Note*: we assume that both Ireland and Northern Ireland are operating an entry-exit regime.

The benefit, as seen from the table is that customers see lower prices. Clearly one disadvantage that would have to be considered is the possibility of gaming. If a participant knows there is a guaranteed minimum booking then they may reduce their own bookings, especially when planned bookings are below the threshold, and seek to exploit the guaranteed capacity already booked. Rules to minimise this could be developed. Also, as a direct Regulatory intervention in what should be a market driven situation, there may be concern that it is in some way unfair. However, given the other options for ensuring security and diversity of supply that might have to be considered linked with other reform options, this would appear to be no less interventionist – although some of the other possibilities could allow direct market evidence on the willingness to pay for security and diversity of supply to be assessed (e.g. an auction).

**Table 5.8: Assessment of asset reallocation (cost reduction) options**

| Criteria | PSO | Cutting the rate of return | Reprofiling | Changing the RAB | Guaranteed IC capacity |
|---|---|---|---|---|---|
| Development of the gas industry | Good. Prices will be lowered for users since the cost of the marginal source of gas will drop. This will make gas usage cheaper.<br>No impact on geographic averaging and if designed correctly no impact on financial viability. | Good. Prices will be lowered for users since the cost of the marginal source of gas will drop. This will make gas usage cheaper.<br>There may be some concern about getting the right signals to invest – although these can be addressed.<br>No impact on geographic averaging. | Good. Prices will be lowered for users since the profile of the cost of the marginal source of gas will change and become less peaky. This will make gas usage cheaper.<br>No impact on geographic averaging and no long-term impact on financial viability (although there may be concerns in the short-term). | Good. Prices will be lowered for users since the cost of the marginal source of gas will drop. This will make gas usage cheaper.<br>No impact on geographic averaging or financial viability. | Good. Prices will be lowered for users since the cost of the marginal source of gas will drop. This will make gas usage cheaper.<br>No impact on geographic averaging or financial viability. |
| Protection of consumers | Good. Consumer prices are kept low and stable. If costs are shifted to the onshore system then minimum impact on gas demand and probably low implementation costs. | Mixed. Costs are kept low for consumers but there may be high set-up costs. | Mixed. Costs are kept low but volatility in prices may still occur. For revenue certainty additional regulatory corrections will be needed. | Mixed. Costs are kept low for consumers. There could be ongoing monitoring needs for suspended assets and set-up costs. | Mixed. Costs are kept low for consumers. There would be both set-up costs and ongoing costs linked with collecting the necessary levy as well as determining when intervention is needed etc. Further, the possibility of |

| Criteria | PSO | Cutting the rate of return | Reprofiling | Changing the RAB | Guaranteed IC capacity |
|---|---|---|---|---|---|
| | | | | | gaming by stakeholders would he high. |
| Security of supply | Mixed. The lower prices would limit the benefit for producers. However, some benefit could be retained, if appropriate, and other ways of encouraging security and diversity of supply could be employed. | Mixed. The lower prices would limit the benefit for producers. However, some benefit could be retained, if appropriate, and other ways of encouraging security and diversity of supply could be employed. | Mixed. The lower prices would limit the benefit for producers. However, some benefit could be retained, if appropriate, and other ways of encouraging security and diversity of supply could be employed. | Mixed. The lower prices would limit the benefit for producers. However, some benefit could be retained, if appropriate, and other ways of encouraging security and diversity of supply could be employed. | Mixed. The lower prices would limit the benefit for producers. However, some benefit could be retained, if appropriate, and other ways of encouraging security and diversity of supply could be employed. |
| Promotion of competition | No real impact. | No real impact. | No real impact. | No real impact. | No real impact. |

**Questions**

**18: Should there be any attempt to mitigate the effect of declining utilisation of the interconnectors?**

**19: Do you feel that we have adequately described the relevant options under the selected criteria?**

## 5.5. Capacity and Commodity charges

Unlike the options to be considered under other areas for reform the options for the appropriate capacity – commodity split are not discrete. Rather they are, in theory, across the spectrum from 0:100 (i.e., all charges being on a throughput commodity basis) to 100:0 (i.e., all charges being on a fixed cost basis).

In reality, however, it is only the range between the regulators' current positions that we consider as part of the current process. From October 2008, Northern Ireland will have a 75:25 split, whilst in Ireland the split is 90:10. Ireland have, however, indicated that they are minded to move to move toward an 80:20 split irrespective of the CAG making the difference between the two minimal.

In the broader European spectrum the range of capacity commodity splits in Ireland and Northern Ireland are broadly in line with other countries. This is demonstrated in Table 5.9 which sets out the splits for a number of European countries.

**Table 5.9 Capacity/Commodity Splits in European Countries**[19]

| | Capacity | Commodity |
|---|---|---|
| Ireland | 90 | 10 |
| Northern Ireland | 75 | 25 |
| France | 100 | 0 |
| Belgium* | 94 | 6 |
| Denmark* | 75 | 25 |
| Hungary* | 70 | 30 |
| The Netherlands | 100 | 0 |

*Average figure.

Broadly speaking the overall impact of any change in the capacity-commodity split is likely to be minimal. It is the distributional impact, however, that is arguably of more interest with different users being affected depending on their load profile (high load factor customers and low load factor customers will see different impacts). This is discussed below. Consequently there is a trade-off between cost reflectivity and distributional impact that needs to be considered.

Typically, best practice amongst European regulators has been to broadly reflect the division between fixed and variable costs in the capacity – commodity split so that fixed costs, such as capex, are recovered through the capacity charge and variable costs, such as opex, are recovered through the commodity charge. From a cost reflectivity point of view there are

[19] ERGEG: Gas Transmission Tariffs, An ERGEG Benchmarking Report (July 2007)

differences in the weighting of costs in each jurisdiction. If fully cost reflective, Ireland would have a very high capacity weighting, potentially as much as 95%. However Northern Ireland is different. The mutualisation of SNIP and the Belfast Gas Transmission Pipeline results in a lower financing charge allowing a lower capacity weighting.

**Development of gas industry**

The likely impact on the development of the gas industry is likely to be low, although if there is a move towards greater commodity tariffs relative to capacity tariffs then there is likely to be positive impact since prices are more linked to the actual consumption than capacity requirements. This could have a positive impact on gas demand for generation, especially as renewables shift gas demand towards open cycle operation.

**Protection of consumers**

For the average user there is very little impact due to the relative split. Again, there is, however, a distributional impact. Those users with peaky demand will face higher charges whilst others with steady load profiles will face lower tariffs. In both cases, based on the experiences changes in the split in the GB changes in tariffs are likely to be marginal[20]. Of course, as the share of renewables in the generation portfolio of both jurisdictions increases there is likely to be a shift in the way that thermal, especially gas, generation is treated. Peaking and back-up plant will be thermal and consequently there would be a preference for greater emphasis on the commodity element. For illustrative purposes, consider two scenarios where there is a base-load and peak plant operating under two different capacity-commodity splits. In Table 5.10 below the impact of the different options are shown in the prices per MWh and therm.

There is also likely to be an impact on residential consumers, although this should be a minimal impact.

With respect to the ease of implementation, across the relevant range under consideration there are no significant differences in implementation of a 75:25 split or, say, an 80:20 split. In general, however, the higher the capacity component the easier it would be to implement as that portion of the tariff is unrelated to throughput and hence has a higher degree of predictability.

**Table 5.10 Effect of different capacity/commodity**

[20] See Appendix 5.4 of the Competition Commission inquiry into the Conveyance and Storage of Gas 1993

| Element | Base load | Peaking |
|---|---|---|
| Demand | 365MWh | 365MWh |
| Load factor | 1.3 | 2 |
| **Scenario 1** | | |
| Capacity (90%) | 711.34 | |
| Commodity (10) | 0.32 | |
| Total Cost | 1,041.54 | 1,539.48 |
| € per MWh | 2.85 | 4.22 |
| C per therm | 8.4 | 12.4 |
| **Scenario 2** | | |
| Capacity (70%) | 553.27 | |
| Commodity (30) | 0.97 | |
| Total Cost | 1,073.30 | 1,460.59 |
| € per MWh | 2.94 | 4.00 |
| C per therm | 8.6 | 11.7 |

In the above simple illustration, the shift from 90:10 to 70:30 increases the effective price for the base load plant by 3% and reduces the peaking plant price by 5%.

**Security of supply**

There is little interaction between the capacity – commodity split and new indigenous sources of gas in the short term. As a result any decision on the split would have little effect on tariffs as indigenous gas comes on stream.

**Promotion of competition**

The potential increased demand would create positive pressures for competition but overall changing the capacity commodity split is likely to have low or minimal impact.

**Other issues**

One final consideration for the choice of capacity and commodity split is the question of the impact on the incentive for the use of gas and its link to wider environmental policy. A low commodity split could, at the margin, encourage the use of gas and consequently work against broader government policy with respect to lowering emissions. Generation policy is increasingly focusing on renewable technologies and it would be perverse to establish an incentive to work against this. Correspondingly the commodity price should be at least at the level of cost allocated to commodity and possibly higher.

**Questions**

**20: Do you feel that we have adequately described the option of harmonising capacity & commodity charges under the selected criteria?**

**21: What is an appropriate level at which to harmonise?**

## 5.6. Tariff smoothing

At present the CER employs smoothing when setting tariffs whilst the Utility Regulator adopts a more accounting based approach. There is, however, an element of revenue smoothing in Northern Ireland when setting tariffs. That is, stability in revenues is sought as opposed to tariffs. This is largely driven by the mutualisation of pipeline assets in Northern Ireland and the requirement by bond holders to see steady stable cash flows.

An assessment of the impact of tariff smoothing very much depends on the type of tariff smoothing being discussed. That is, with control period smoothing or smoothing across periods – effectively reprofiling. In this section we discuss both referring to the former as smoothing and the latter as reprofiling.

**Development of gas industry**

Tariff smoothing is unlikely to have a significant impact on the development of the gas industry. Cost reflectivity is retained, although not necessarily on a year-to-year basis and the degree of geographic averaging will not be affected. Financial viability is also unlikely to be affected.

**Protection of consumers**

This approach would smooth any peaks and troughs in tariffs and so consumers will face less volatile prices which is beneficial. There are no obvious implementation issues with adopting tariff smoothing relative to an accounting based approach.

**Security of supply**

Both smoothing and reprofiling have an impact on the ability of indigenous producers to benefit from peaky prices. Clearly the longer the period of the smoothing the fewer the peaks and the less able a producer is able to gain. However, since the average tariff over the life of the asset is not being changed the indigenous producer could still benefit from the same average difference. Those producers that have a different field life might be disadvantaged since their ability to benefit from the timing impact would be more limited – again this would disadvantage fields with relatively short lives like Corrib more than LNG which has an asset life more in line with the transmission network.

**Promotion of competition**

If the high peaks in tariffs encourage competition in supply then smoothing will have a detrimental impact on competition. However if a consequence of high peaks in tariffs is reduced

demand, then smoothing would mitigate any such effect and maintain a larger market where competition amongst shippers/suppliers may flourish. As such it is unclear what the overall impact of reprofiling is with respect to competition.

**Other issues**

As mentioned above, one of the reasons for not smoothing tariffs in Northern Ireland is to accommodate the requirements of the bond holders of the mutualised assets. Options for resolving this, e.g. adopting a revenue smoothing approach, largely dependent on decisions made elsewhere in the harmonisation process such as the entry/exit decision. We do not believe that this is a priority area since it is secondary to the main question of the future tariff methodology.

## 5.7. Auctions

The final alternative to consider is that of using auctions to set the entry tariffs. This approach is used in GB for determining entry capacity tariffs for gas. In principle, using auctions which harness market information about demand and supply should provide strong signals about the price that users are willing to pay for the services provided. Some issues to consider include:

- whether auctions are likely to raise sufficient revenue to cover costs for each transmission line and how additional revenues are raised if the total from the auctions is insufficient to meet the total cost (in Great Britain a commodity charge is levied if the capacity revenues prove insufficient);
- the interaction of the level of competition for gas customers in Northern Ireland and Ireland with the likely level of competition for the auctions for entry capacity – the level of competition currently in place is low and with the excess capacity that currently exists, and is forecast to grow, it is far from clear that the auctions would raise sufficient revenue or provide meaningful signals about consumption or investment; and
- the situation in Northern Ireland is likely to be quite different. If Northern Ireland continues to operate a separate gas tariff methodology then auctions might be a viable way of allocating access to the SNIP which would continue to be the primary route for delivering gas. Prices could be bid-up towards the IC tariff cost since the IC is the alternative source of gas – this would also have the impact of raising additional revenue.

Table 5.11 summarises the assessment of auctions. Overall, the existing competitive situation in the gas industry is such that auctions are unlikely to prove to be a viable option, although there may be some specific circumstances where they could be used within one jurisdiction.

**Table 5.11: Assessment of Auctions**

| Criteria | Assessment | Comment |
|---|---|---|
| Development of the gas industry | Mixed | Auctions would send clear signals about where investment should be focused but, given the current situation, are unlikely to lead to efficient consumption signals. Provided auctions were limited to the entry points they would not have an impact on geographic averaging.<br>They may, however, have implications for financial viability and consequently additional rules may be necessary to ensure sufficient revenue is recovered. |
| Protection of consumers | Poor | Unlikely to produce the lowest prices and may even have a negative impact on the provision of entry infrastructure unless additional rules to protect revenue requirement are put in place. |
| Security of supply | Potentially poor | Given the state of the market it is unlikely that auctions will lead to strong signals for investment in either the security or diversity of supply. Whether this is appropriate or desirable for the island is not clear. |
| Promotion of competition | Potentially poor | The existing structure of the gas market is unlikely to be changed to a more competitive environment through the introduction of auctions. |

**Questions**

**22: Do you agree with our analysis of the applicability of auctions?**

# 6. Next steps

The role of this consultation paper is to provide:

- a framework for analysing reform options;
- a first view of the range of possible reforms; and
- an initial assessment of the reforms.

It is not the role of this paper to propose a preferred option. However, what is clear is that based on our initial analysis some options are more viable than others. We summarise what we believe to be the viable options, along with their perceived strengths and weaknesses, in table 6.1 below. The single entry and Moffat entry options only make sense if the multiple exit option is also chosen. These would seem to be the options most worthy of further analysis and comment.

**Table 6.1: Summary of viable options**

| Option | Strengths | Weaknesses |
|---|---|---|
| Postalisation | Reduces prices for Ireland customers and minimises increase for Northern Ireland customers. Smoothes volatility.<br>Simple.<br>Appropriate for a relatively small market. | Lose incentive for development of indigenous sources (may require a separate incentive to deliver this in the future if an incentive is needed).<br>Implementation issues re common currency and loss of route for revenue transfer.<br>The degree of cost reflectivity means development is undertaken that is not necessarily economically justified. |
| Single entry point | Retains entry-exit system in Ireland it introduces it for Northern Ireland.<br>Reduces price level for Ireland customers and smoothes volatility.<br>Retains a degree of incentive for development of indigenous sources (although less than under the combined Moffat). | Raises prices for customers in Northern Ireland (even if done in conjunction with retention of postalisation).<br>Common currency issue has to be addressed.<br>Uncertain if sufficient incentive for development of indigenous sources. |
| Combined Moffat entry point | Retains entry-exit system in Ireland it introduces it for Northern Ireland.<br>Reduces price level for Ireland customers and smoothes volatility.<br>Retains a degree of incentive for development of indigenous sources. | Raises prices for customers in Northern Ireland (even if done in conjunction with retention of postalisation).<br>Common currency issue has to be addressed.<br>Uncertain if sufficient incentive for development of indigenous sources. |
| Two exit zones | Within jurisdiction postalisation keeps control simple.<br>Offers a route for revenue transfer.<br>Provides a degree of cost reflectivity. | The degree of cost reflectivity means development is undertaken that is not necessarily economically justified. |
| Reprofiling linked with some cost reduction | Reduces prices for Ireland customers and smoothes volatility.<br>Retains a degree of incentive for | Cost reduction unlikely to have significant impact.<br>Reprofiling smoothes the volatility but only moves cost |

| | | |
|---|---|---|
| | development of indigenous sources. | about, it does not reduce them. Could cause uncertainty about revenue recovery. |
| Guaranteed minimum capacity bookings | Minimises volatility whilst retaining incentives for indigenous producers | Guaranteed minimum capacity presumes that the deciding agency knows what level to set the floor. |

Table 6.2 provides a summary of the impact of the reforms. It is based on measuring the change in consumer payments over the ten year period from 2010. It assumes that the whole island is operating an entry-exit regime at that point (so Northern Ireland adopts the existing IBP), essentially a "do nothing" scenario. To provide a benchmark, if the existing regime operated over this period the IBP would yield about €6.6 Billion more than that needed to meet the costs of the transmission operators.

**Table 6.2: Impact of different approaches, cost and savings to customers.**

| **Approach** | **Total cost (€m)** | **Additional cost to customers over cost base** | |
|---|---|---|---|
| | | In €m | In c/therm |
| Cost base* | 2,549 | - | - |
| Do nothing scenario (Charge at IC)** | 9,159 | 6,610 | 22.5 |
| Charge at Moffat*** | 3,649 | 1,100 | 3.7 |
| Charge at All-entry**** | 2,554 | 5 | 0.0 |

Note: – assumes whole island is operating an entry-exit regime and that no NDM discount is provided;

*Cost base is the sum of the revenue requirements for each transmission asset over the period.

**Charge at IC implies that entry points are kept separate and the Ireland ICs are the marginal source of gas. This is essentially a do nothing scenario

***Charge at Moffat implies that the three Moffat interconnectors are combined

**** Charge at All-entry implies a single entry point (all entry points combined)

**Questions**

**23: Do you agree with our selection of viable options for further analysis?**

- **What additional options should be included for further analysis and why?**
- **What options should be excluded from further analysis and why?**

**24: Which is your preferred option for entry / exit?**

**25: Which is your preferred option for mitigating the effect of declining interconnector utilisation?**

# Annex 1: Financial modelling

## A1.1 Objectives and overview

For this work a simple, flexible model was developed to calculate the possible capacity and commodity gas transmission tariffs in a harmonised context.

At a high level, the model converts a series of inputs, related to anticipated gas demand, required revenue, cost of capital etc., into gas transmission tariffs. It also enables the user to:

- sensitise the inputs, thus testing the direction and magnitude of change in the tariffs given changes in the inputs; and
- test the effects on tariffs from different scenario assumptions, primarily as related to combining different (currently separate) entry and / or exit controls.

The model is set out over a 12 year period, until 2019/20 gas year – assumed be to from October to September of a calendar year. An overview of the model structure is provided in Figure A1 below.

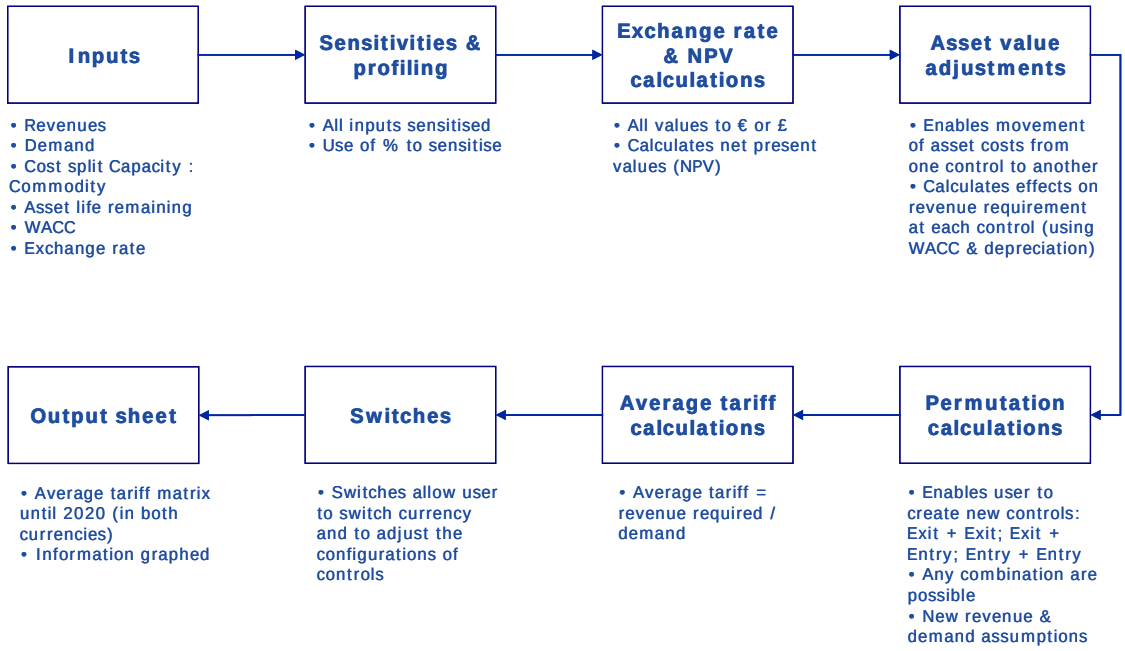



**Figure A1: Model structure**

## A1.2 Key assumptions and inputs

Data for key inputs in the model has been provided by the stakeholders – the two regulatory authorities and gas transmission companies. Key inputs and their descriptions are set out in Table A2 below.

**Table A2: Key inputs**

| Input | Explanation |
|---|---|
| Revenues | This is the allowed revenue for each control, based on the most recent, respective, revenue / price control determination by the regulatory authority of a particular entry or exit control. |
| Demand | Anticipated capacity (MWh/day) and commodity (MWh) demand as related to each entry and exit control. |
| Capacity/ Commodity tariff split. | Regulatory authorities assume that a proportion of the required revenue should be recovered through capacity charges and a proportion through commodity charges – this is the capacity/ commodity split. |
| Asset life remaining | The number of economically useful years of operation that the asset in question is assumed to have. |
| WACC | The assumed weighted average cost of capital for the control in question. |
| Exchange rate. | The assumed Euro and Pound Sterling exchange rate. |

All of these inputs can be sensitised to test the magnitude and direction of changes to tariffs from any movements in the value of these inputs.

## A1.3 Methodology

There are three key methodologies within the model. These are: (i) calculating the tariffs; (ii) changing the asset value allocation; and (iii) testing combinations of different exit and / or entry controls. All the calculations are undertaken in one currency, depending on the user's choice – Euros or Pounds Sterling.

### Calculating the tariffs

The model calculates the average gas transmission tariff for each of the modelled years in the following manner:

- The revenue requirement in each year for a particular control is multiplied by the proportion assumed to be recovered through capacity charges (e.g. 90%).

- The resulting revenue requirement is then simply divided by the relevant capacity demand, to arrive at a tariff per unit of capacity (i.e. MWh/day).
- The same methodology is applied to commodity tariffs, arriving at a tariff per unit of commodity (i.e. MWh).

**Changing the asset value allocation**

The model allows the user to introduce marginal changes to the value of the RAB for any of the controls in question. RAB can be moved from one control to another, suspended from one control without it being passed on to another, and /or increased (as a result of investment) for any one of the controls.

These marginal changes to RAB have an impact on the required revenue for the affected control(s). The impact is made up of a depreciation charge (on the RAB value that is affected) and a return on capital charge on the depreciated RAB value in question.

For example, if £10m of RAB, with another 50 years economic life left, is moved from an entry control which has a WACC value of 5%, then the net impact in the first year of the move on revenue is:

- depreciation charge of £200k (£10m / 50 years); and
- return on capital charge of £490k ((£10m – £0.2m) * 5%); giving
- a total decrease of £690k in required revenue for the first year.

In the following year, this reduction will be smaller, as the value of the marginal RAB that was moved depreciates, and therefore the return on capital charge will be lower.

If this RAB value is added to another control, a similar process is followed to ascertain what the increase in the annual revenue requirement will be.

**Combining different exit and / or entry controls.**

The model allows the user to combine any two or more entry and / or exit controls into a single control block. The model then calculates the combined tariff for this block as a whole, using the methodology for calculating tariffs as described above.

## A1.4 Outputs

The model outputs are capacity and commodity gas transmission tariffs, for each individual control and / or a block of controls. These are tabulated and graphed for the convenience of the user.

The outputs can be presented in either Euros or Pound sterling.

## Annex 2: Statutory Objectives on the Utility Regulator and CER

**Energy (Northern Ireland) Order 2003**

**The principal objective and general duties of the Department and the Authority in relation to gas:**

**14.** - (1) The principal objective of the Department and the Authority in carrying out their respective gas functions is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland.

(2) The Department and the Authority shall carry out those functions in the manner which it considers is best calculated to further the principal objective, having regard to -

(a) the need to protect the interests of consumers of gas;

(b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Gas Order or this Order;

(c) the need to secure that the prices charged in connection with the conveyance of gas through designated pipe-lines (within the meaning of Article 59) are in accordance with a common tariff which does not distinguish (whether directly or indirectly) between different parts of Northern Ireland or the extent of use of any pipe-line; and

(d) the need to protect the interests of gas licence holders in respect of the prices at which, and the other terms on which, any services are provided by one gas licence holder to another.

(3) In performing that duty, the Department or the Authority shall have regard to the interests of -

(a) individuals who are disabled or chronically sick;

(b) individuals of pensionable age; and

(c) individuals with low incomes;

but that is not to be taken as implying that regard may not be had to the interests of other descriptions of consumer.

(4) The Department and the Authority may, in carrying out any gas functions, have regard to the interests of consumers in relation to electricity.

(5) Subject to paragraph (2), the Department and the Authority shall carry out their respective gas functions in the manner which it considers is best calculated -

(a) to promote the efficient use of gas;

(b) to protect the public from dangers arising from the conveyance, storage, supply or use of gas;

(c) to secure a diverse and viable long-term energy supply; and

(d) to facilitate competition between persons whose activities consist of or include storing, supplying or participating in the conveyance of gas;

and shall have regard, in carrying out those functions, to the effect on the environment of activities connected with the conveyance, storage or supply of gas.

Functions of Commission.

**9.**—(1) The Commission shall have the following functions, namely—

(*a*) to publish, pursuant to a policy direction or directions of the Minister, which shall be made publicly available when given to the Commission, proposals for a system of contracts and other arrangements, including appropriate rights and obligations, for trading in electricity,

(*b*) to engage in a public consultation process on the procedures to be adopted by the Commission to implement the proposals drawn up under *paragraph (a)*,

(*c*) to advise the Minister on the impact of electricity generation in relation to sustainability, and international agreements on the environment to which the State is or becomes a party,

(*d*) following the public consultation process referred to in *paragraph (b)* and taking account of matters raised in the public consultation process, to make regulations, subject to the consent of the Minister, establishing a system of trading in electricity, including the supervision and review of such a system by the Commission, and

(*e*) to advise the Minister on the development of the electricity and gas industries, as appropriate, and on the exercise of the functions of the Minister under this Act.",.

(2) Notwithstanding the generality of *subsection (1) (a)*, a policy direction of the Minister shall include a direction that procedures of the Commission enable the implementation of orders made by the Minister under *sections 39* and *40*.

(3) It shall be the duty of the Minister and the Commission to carry out their functions and exercise the

powers conferred on them under this Act in a manner which—

(*a*) in relation to electricity, does not discriminate unfairly between holders of licences, authorisations and the Board or between applicants for authorisations or licences,

(*b*) in relation to gas, does not discriminate unfairly between holders of licences, consents and Bord Gáis Éireann or between applicants for consents or licences, and

(c) the Minister or the Commission, as the case may be, considers protects the interests of final customers of electricity or gas or both, as the case may be.",

(4) In carrying out the duty imposed by *subsection (3)*, the Minister and the Commission shall have regard to the need:

(*a*) to promote competition in the generation and supply of electricity and in the supply of natural gas in accordance with this Act;",

(*b*) to secure that all reasonable demands by final customers of electricity for electricity are satisfied;

(*c*) to secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake;

(*d*) to promote safety and efficiency on the part of electricity and natural gas undertakings;

(*e*) to promote the continuity, security and quality of supplies of electricity;

(*f*) to promote the use of renewable, sustainable or alternative forms of energy;

(*g*) to secure that there is sufficient capacity in the natural gas system to enable reasonable expectations of demand to be met; and

(*h*) to secure the continuity, security and quality of

supplies of natural gas.”.

(5) Without prejudice to *subsections (3)* and *(4)*, it shall be the duty of the Commission:

(*a*) to take account of the protection of the environment;

(*b*) to encourage the efficient use and production of electricity;

(*c*) to take account of the needs of rural customers, the disadvantaged and the elderly;

(*d*) to encourage research and development into—

(i) methods of generating electricity using renewable, sustainable and alternative forms of energy and combined heat and power, and

(ii) methods of increasing efficiency in the use and production of electricity;

and

(*e*) to require that the system operator gives priority to generating stations using renewable, sustainable or alternative energy sources when selecting generating stations.

## Better Regulation Principles

Both the UK and Ireland have government agencies tasked with establishing general guidance and principles on good regulation. In the UK this is the task of the Better Regulation Executive (part of BERR) and in Ireland the Better Regulation Unit (within the Taoiseach's Department).[21]

Both groups have sets of overall principles that are expected to be followed, these are summarised in Table A2.1 below.

**Table A2.1: Better Regulation Principles**

| UK | Ireland |
|---|---|
| Transparency | Transparency |
| Accountable | Accountable |
| Proportionate | Proportionate |
| Consistent | Consistent |
| Targeted | Necessary |
| | Effective |

*Sources*: BERR website and *Regulating Better Government* White Paper available from the Better Regulation website.

As can be seen, there is a significant overlap between the two sets of principles with the only real difference being an explicit principle of effectiveness being stated in Ireland.

[21] There is a separate Better Regulation group within the Northern Ireland Department of Enterprise, Trade and Investment.

## Annex 3: Non-annual gas capacity product principles

Non Annual Gas Products

- Current EC principles for pricing short term tariffs include[22]:
    - Transparency;
    - Cost reflective including an appropriate return;
    - Non-discriminatory; and
    - Take account of system integrity and need for improvements
- In Ireland, BGN have developed its own principles. Short term tariffs should:
    - Take account of system integrity, be cost reflective and take account of seasonal nature of capacity demand;
    - Incentivise efficient use of the network and hence increase gas use where appropriate (eg over summer);
    - Provide an incentive to book long term capacity, where users have long term capacity requirements; and
    - Be simple to understand, and be set via a transparent methodology.

This note sets out the principles and high level workings of non-annual gas products in Ireland and Northern Ireland.

**Inventory Products**

**Ireland**

In Ireland at present there is an Inventory Product available on the Moffat Interconnectors. This was run as a pilot first and was subsequently made available to all shippers on 1st May 2008.

The principles under I/C Inventory product is priced are as follows are as follows.

The pricing should be:

- Cost reflective or market based

[22] EC 1775/2005

- Transparent
- Applied in a non-discriminatory manner
- Simple to understand
- Be based on the assumption that Shippers holding valid Long Term Entry Capacity bookings at Moffat will be given preference for access to this service/product

Directive 2003/55/EC states that where a storage facility, linepack or ancillary service operates in a sufficiently competitive market, access could be allowed on the basis of transparent and non-discriminatory market-based mechanisms.

The April 2007 CER Decision (CER/08/052) sets out the pricing structure for the inventory product in Ireland. The current product is priced based on a benefit sharing mechanism where any financial gains made by the shipper are shared 50:50 with the transporter.

A small reservation charge applies when booking the product and users of the product also incur shrinkage and CO2 costs as appropriate.

**Northern Ireland**

There is currently no inventory product available in Northern Ireland

**Short Term Products**

**Ireland**

Regulation EC1775/2005 deals with the conditions for access to the natural gas transmission networks. The regulation states that tariffs, or the methodologies used to calculate them, shall,

- Be transparent
- Take account the need for system integrity and its improvement
- Reflect the actual costs incurred (insofar as such costs correspond to those of an efficient and structurally comparable network operator and are transparent)
- Include appropriate return on investment
- Be applied in a non discriminatory manner

Tariffs are also required to:

- Facilitate efficient gas trade and competition

- Avoid cross-subsidies between network users
- Provide incentives for investment and maintaining or creating interoperability for transmission networks

Finally, tariffs for network access must not restrict market liquidity nor distort trade across borders of different transmission systems.

The following principles were adopted in Ireland for the pricing of the short term products.

1. Short term tariffs should
    - Take account of the need for system integrity, reflect the drivers of network costs, and therefore reflect the seasonal nature of capacity demand
    - Incentivise efficient use of the network and hence increase gas use where appropriate (e.g. over the summer)
    - Provide an incentive to book long term capacity, where users have long term capacity requirements; and
    - Be simple to understand, and be set via a transparent methodology.
2. The introduction of short term tariffs should result in minimal increase in the volatility of the transmission tariffs overall.
3. Tariffs should allow for the full recovery of any historic under-recovery by BGN relative to allowed revenue. They should also allow for the full payback of any historic over-recovery.

Short-term gas products have been available in Ireland since October 2007. The pricing of the short-term product was set out in the August Decision Paper CER/07/115. The current short term multipliers (of the annual tariff) are set out in the table below. The Commission has committed to carrying out a review of the products a year after their introduction.

| 2007/08 Multipliers | Month | Day |
|---|---|---|
| October | 15% | 0.75% |
| November | 15% | 0.75% |
| December | 20% | 1.33% |
| January | 35% | 2.33% |
| February | 40% | 2.67% |
| March | 30% | 2.00% |
| April | 15% | 0.75% |
| May | 8% | 0.40% |
| June | 8% | 0.40% |
| July | 8% | 0.40% |
| August | 8% | 0.40% |
| September | 8% | 0.40% |
| Total Percentage of Annual Tariff | 210% | 380% |

**Northern Ireland**

Short Term Products are currently not available in Northern Ireland. Such products have not been introduced as the Utility Regulator did not wish to undo the work once CAG goes live.

**Storage Tariffs**

**Ireland**

There is a storage facility in Ireland which is operated by Marathon and is located at Kinsale. It is accessed using the Inch Entry (exit) point. The arrangements for Exit flows at Inch are set out in the CER Decision CER/06/154. Gas travelling from GB to the Ireland Onshore via the storage facility would incur the following:

- Gas purchased at NBP
- Appropriate Moffat charges are paid exiting the GB system
- The IC tariff is paid
- The commodity element of the Inch Entry tariff is paid (when entering the storage)
- The capacity and commodity element of the Inch Entry tariff is paid on re-entry to the Ireland Onshore System

- The full onshore capacity and commodity tariff is paid.

**Northern Ireland**

Currently there are no gas storage facilities in Northern Ireland. However a storage facility within salt strata at Larne Lough basin has been proposed. Seismic surveys have indicated positive results. Assuming progress, it is the intention of the developers to commence storage operation from 2014/15.

**Interruptible Gas Capacity Products**

**Ireland**

Interruptible products are a requirement under EC 1775. In Ireland, business rules have been developed within the Code Mod Forum for the offering of such a product. However it has since been decided that the product will not go any further than the business rules development at this time. Instead the product will be examined as part of the CAG.

However, the product as developed so far has the following features

- It would be available at all Entry Points
- It would be based on Use It Or Lend It principles
- The product would only be made available once all firm capacity (Annual, Monthly, Daily) was sold at the relevant entry point i.e. the Capacity Booking are greater than or equal to the technical capacity of the entry point.

From a pricing perspective the follow principles would apply

- understood and will be applied in a non-discriminatory manner.
- The Interruptible Capacity Price shall reflect the probability of interruption, consistent with Article 4 of the Regulation.

The methodology used to calculate the pricing of Interruptible Capacity will be transparent, easily

It had been proposed that the Interruptible Capacity Price for Entry Points would be calculated using the following formula.

Interruptible Capacity Price = Daily Firm Price [1] * (1 – Interruption Probability)

**Northern Ireland**

Premier Transmission Limited currently offer interruptible product on the SNIP and the Belfast Gas Transmission Pipeline. This product is written into PTL and BGTL Network Codes.

BGE (NI), with the support of the Utility Regulator, intends to offer interruptible products on the South-North and North West pipelines. The introduction of a BGE (NI) interruptible tariff is imminent.