Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

TRANSMISSION AND DISTRIBUTION TARIFFS OBJECTIVES AND PRINCIPLES

CONSULTATION DOCUMENT

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1. INTRODUCTION

Under section 14 (3) of the Gas (Interim) (Regulation) Act, 2002, the Commission may give directions to a pipeline operator in respect of the basis for charges for the transportation of gas through the pipelines of the pipeline operator.

In its Natural Gas Policy Framework document[1], the Commission identified as one of the key areas of the reform of the gas market arrangements the full review of the charging regime for gas transmission and distribution services in time for the gas year starting 1 October 2003. The purpose of this Consultation Document is to invite comments from interested parties on the broad framework to be applied in this review. This document has been drafted recognising that BGE are currently the only operator of transmission and distribution services in Ireland but that the potential for competition in both exists under the legislation.

This report does not cover the regulation of current and new transmission and distribution connections. The Commission will publish separate papers on this topic.

The document is structured as follows:

- Section 2 identifies the principles of good regulation;
- Section 3 describes the economic characteristics of network services and the regulatory objectives that result from those characteristics;
- Section 4 discusses the appropriate form of regulation for the transmission and distribution businesses in Ireland;
- Section 5 makes proposals on the calculation of the transmission and distribution revenue requirement;
- Section 6 discusses the objectives and principles for setting tariffs for different transmission services;
- Section 7 discusses the objectives and principles for setting distribution tariffs; and
- Section 8 discusses the different options to deal with issues surrounding the Second Scotland-Ireland Interconnector (IC2).

All interested parties are invited to comment on the proposals and issues set out in this Consultation Document. Comments should be sent to the Commission ***no later than Friday 11th April 2003***.

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[1] Natural Gas Policy Framework, CER/02/83. 19 July 2002.

The Commission would prefer comments in electronic format. These comments should be sent to:

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The Commission is planning to make these comments public and would encourage respondents to do the same. Any information that respondents wish to submit in confidence may be submitted separately, clearly marked as such. The Commission would however prefer public comment wherever practicable.

2. PRINCIPLES OF GOOD REGULATORY PRACTICE

As the Commission has stated elsewhere during its review of the electricity transmission and distribution revenues[2] the best practice regulation of the so-called natural monopolies can be characterised as sustainable, stable, transparent, predictable and cost-effective.

The Commission's task essentially consists of creating a framework within which, in return for providing monopoly services to an acceptable quality, the regulated business receives a reasonable assurance of a revenue stream in future years that will cover its efficient costs, including an appropriate rate of return on investments made and the recovery of capital invested. The regulatory framework therefore needs to be **sustainable**. The regulated business must be able to finance its operations, and any necessary capital expenditure, so that it can continue to operate in the future to the ultimate benefit of customers.

To be **stable**, the framework must also satisfy all the parties affected by it - customers, the Government (acting on behalf of customers and as BGÉ's shareholder), BGÉ itself, and independent Shippers and suppliers. Frequent complaints and disputes will lead to the regime being continually adjusted by the Commission. This creates uncertainty in the industry and discourages investment and long-term planning. The stability of the regime is particularly important to privately owned businesses, if investors are to be encouraged to make long-term investments in the sector.

The rules that govern the regulatory regime should also be **transparent** in their interpretation and **predictable** in the way they are applied. In particular, it should be clear how costs relate to prices. Regulations that are unclear will cause disputes, which create instability in the regulatory regime, add to the costs of regulation, and are likely to raise the cost of capital, ultimately to the detriment of customers in the form of higher prices.

An important corollary is that there should be "no surprises" for participants (customers and businesses). This does not imply that the Commission cannot change its view on issues, or revise the regulatory framework as necessary and in response to unforeseen developments. But it does mean that the Commission will endeavour to:

– avoid changes which apply retroactively, with adverse consequences for the regulated businesses;

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2 Draft Principles for the Regulation of Distribution and Transmission Revenues, A Consultation Paper, CER/99/04. 13 October 1999.

- take decisions following a due process of consultation and consideration of the relevant issues; and

- publish a full account of the reasoning behind those decisions.

The **costs of monitoring and enforcing compliance** with licences and codes need to be low relative to the benefits of regulation. Ideally, the regulatory framework will involve minimum costs of data collection and analysis. The procedure for processing disputes should also be simple, although the more transparent and stable the regulatory system, the less often disputes will arise.

The Commission intends to operate within a regulatory framework that has the objective of being stable, predictable, clear and simple and such that market participants are able to carry on their activities in as unconstrained a manner as possible, while ensuring that they do not take advantage of positions of monopoly or market power.

3. ECONOMIC CHARACTERISTICS OF NETWORK INDUSTRIES AND ECONOMIC REGULATORY OBJECTIVES

Before discussing the regulatory framework for transmission and distribution services, this Section briefly describes the economic characteristics of those services and the regulatory objectives that result from those characteristics.

3.1. Economic Characteristics

Economic regulation is needed when competition is not feasible or insufficient to protect the interest of customers. This often applies in network industries, such as gas transmission and distribution, where the presence of large economies of scale means that services are more efficiently provided by a single firm in a specific area.

Natural monopolies have the potential to abuse their dominant position. In the absence of price and quality regulation, a profit-maximising monopoly may increase its profits by setting prices above its costs (and/or reducing the quality of the service) hence reducing demand below the economically optimal level. High prices not only allow the firm to earn profits that are higher than they need to be, but also discourage demand that could be met at a cost that consumers are willing to pay. The effect on demand results in a loss of potential benefits to society defined as a reduction in economic efficiency.

In such cases regulation seeks to ensure that the firm does not charge excessive prices, that it does not hinder or prevent access to networks by third parties (i.e. open access), or that it denies an appropriate quality of service.

3.2. The Objectives of Economic Regulation

Gas transportation (i.e. transmission and distribution) is commonly subject to economic regulation on the grounds that the industry exhibits the attributes of a natural monopoly. The desire to avoid monopoly pricing, poor quality of service and market foreclosure yields a set of regulatory objectives that generally apply within any regulatory framework.

The starting point for natural monopoly regulation is simply the desire to bring prices towards the level of costs, including the costs of capital, and hence to increase the demand for transportation services to the optimal level. Such interventions increase *allocative efficiency*, i.e., the efficiency with which customers choose which services to consume (and hence the efficiency with which resources are allocated to production or services).

Setting prices in line with costs helps customers to allocate their expenditure efficiently – and prevents monopoly profits.

To increase efficiency overall, monopoly regulation must also provide incentives to reduce costs. If prices are set equal to costs (including the cost of capital) at all times, then the monopolist has no incentive to minimise costs, since increases in cost would be reflected in an increase in prices. Such a regime would allow costs to rise and would reduce *productive efficiency,* i.e., the efficiency with which the firm produces a given level of output. Indeed, some criticisms of approaches to regulation conclude that setting prices equal to costs may actively encourage inefficient forms of production and higher costs. Therefore, all regulatory regimes offer some incentive for regulated firms to reduce their costs, essentially by reducing profits if the firm is inefficient, and/or increasing profits if the firm is efficient.

The application of these general terms, allocative and productive efficiency, to natural monopolies, in this case gas transportation, implies two more specific objectives.

First, a large proportion of the transmission and distribution costs are fixed. Therefore, the transporter should be allowed to *earn a reasonable rate of return* to preserve its credit quality and maintain continuous access to funds, so it can undertake the necessary investments.

Second, the regulatory regime must ensure that the transporter cannot respond to incentives to cut costs merely by reducing the *quality* of its service. Under some regulatory mechanisms, this form of cost cutting may increase the profits of the regulated firm, but would not serve the interests of customers. Consequently, monopoly regulation must offer incentives for the transporter to provide adequate *service quality*.

3.3. The Commission's View

In assuming its role as regulator of transmission and distribution services, the Commission's main duties are to:

- protect the interest of customers, both in respect of the prices charged by transmission and distribution businesses and the quality of the services provided; and
- ensure that transmission and distribution businesses do not unduly discriminate between customers or classes of customers in the provision of transmission and distribution services.

With those duties in mind the Commission would have regard to the maintenance of a financially viable gas sector.

In order to do that, the Commission proposes that any system of regulation adopted for gas transportation tariffs must try to achieve the following objectives:

1. Allocative efficiency
2. Productive efficiency (low cost provision of service and low cost investment given the other objectives of the Commission e.g. safety)
3. Ability to earn a reasonable rate of return
4. Maintenance of adequate service quality

The three first objectives are directly related to the regulation of transmission and distribution tariffs, which is the subject of this Consultation Document. Regarding objective 4, the Commission will approve standards of performance to ensure that transmission and distribution businesses provide adequate transmission and distribution service quality.

4. FORM OF REGULATION

Any form of regulatory control must be detailed to meet the regulatory objectives set out in Section 3, but discussions generally focus on two "typical" forms of regulation: Cost of Service (COS) regulation, and "incentive" regulation. Some discussions suggest significant differences between the intellectual and procedural methods underlying each form of regulation. However, all forms of regulation tend to be constrained by the economic objectives set out above, so the differences between these two approaches are, in practice, rather subtle.

4.1. Cost of Service (COS) Regulation[3]

COS regulation aims to eliminate excess profits by equating revenue with actual costs. The regulated firm is allowed to charge tariffs that will cover its operating costs and provide it a reasonable rate of return on the value of the existing capital employed in the business.

The traditional form of COS regulation revolves around tariff reviews. Such reviews can be initiated either by the regulated firm or by the regulator (often acting on a complaint from another interested party). A review normally takes place if a change in circumstances causes the firm's rate of return to reach a level that is unacceptably high (to the customer/regulator) or unacceptably low (to the firm).

4.2. Incentive Regulation

Incentive regulation involves the setting of prices (or revenue) for a specified period within which the regulated firm retains all efficiency gains. Incentive regulation mimics the desirable incentives for cost minimisation found in competitive markets, where prices are generally set without reference to the costs of individual producers but by reference, in principle, to conditions in the market as a whole. Revenues or tariffs within the specified period are adjusted annually according to a revenue or price control formula.

Incentive regulation differs from COS regulation in the following respects:

- First, the period between tariff reviews (i.e. control period) is pre-specified, so that a tariff review is not triggered by a change in the firm's rate of return within the control period. Under COS, the control period is open ended and unknown in advance. It could be as short as one year or as long as several years, depending on how the firm's costs behave;

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[3] This kind of regulation is sometimes called "rate of return regulation".

- Second, the outcome under incentive regulation may be a form of control defined in terms of total revenues, or average prices, rather than a detailed set of tariffs for particular services, so that the regulated firm has scope to adjust the balance of tariffs (within limits); and

- Third, since the revenue or price control must last for a defined period under incentive regulation, the formula will contain a number of indices or factors that update maximum revenues in the light of unpredictable or expected changes; for example, the inclusion of a consumer price index (CPI) accounts for general inflation, whilst an "x-factor" builds in an annual rate of change designed to match the expected rate of growth in relative productivity. There may also be terms in the formula linking revenues or price caps to cost drivers, such as the number of units transmitted or the number of customers served, thereby allowing revenues to move more closely in line with costs than would be the case, for example, if total revenues were fixed in absolute terms.

The effect of adopting this approach is to give the regulated company a profit incentive to reduce the costs of providing a given quality of service within each regulatory or control period.

4.3. The Commission's View

The Commission's position is that where there is scope for reduced costs (i.e. increased productive efficiency), a form of *incentive regulation* should be used. The Commission proposes to use different forms of incentive regulation for (1) transmission and distribution investments subject to consent and (2) other transmission and distribution investments and costs.

4.3.1. Form of incentive regulation for transmission and distribution investments subject to Consent

Section 39A of the Gas Act, 1976 requires any party proposing to construct a gas distribution or transmission pipeline to have the consent of the Commission.[4] The consent procedure will give the Commission opportunity to assess *ex-ante* (1) whether such pipeline can be justified by the expected demand, (2) whether such pipeline satisfies all the necessary technical criteria and (3) the efficiency of the estimated level of construction costs. Since the Commission will approve *in advance* consent investments, the consent process may limit the scope of implementing incentive regulation in the form of a revenue or price cap for this type of investments.

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[4] Under Section 39A of the 1976 Gas Act (as amended), anyone wishing to construct a pipeline (other than an upstream pipeline) must apply to the Commission for a consent to construct the pipeline. The Commission can attach conditions requiring to be observed with regard to the construction and operation of the pipeline issued with a consent to construct.

However, given that the level of actual construction costs will be influenced by the transportation company's actions, the Commission considers that in order to protect the interests of customers, a form of incentive regulation should still be placed on such investment.

Therefore, the Commission proposes that a target construction cost for each new pipeline subject to consent be established. If the party building the pipeline manages to complete the investment for less than the target cost, it would share the savings with gas customers. If the company exceeds the target cost, the company bears most of the cost overrun. The target cost will be equal to company's construction cost estimations submitted to the Commission for approval as part of the consent process. The Commission will review the estimations to ensure that they are prudent and reasonable. The Commission considers that this form of incentive regulation will provide incentives to transmission and distribution business to minimise pipeline construction costs. This will protect the interest of gas customers.

4.3.2. Form of incentive regulation for other transmission and distribution investments and costs

In addition to pipeline investments subject to consent, transmission and distribution businesses will incur additional transmission and distribution costs. These additional costs include (1) transmission and distribution investments that are not subject to consent, and (2) transmission and distribution operating expenditures. The Commission proposes to use a price or revenue cap (i.e. CPI-X mechanism) for the regulation of these additional transmission and distribution costs. The Commission believes that the CPI-X mechanism provides incentives to efficiency on the part of the regulated business, while providing an assurance to customers that the benefits of efficiency gains will be reflected in lower prices in the longer term. The Commission has requested BGÉ's information on transmission and distribution costs. Once the Commission receives this information, it will identify each of the transmission and distribution cost drivers to determine the appropriate form of the price or revenue control formula to be applied to BGÉ's transmission and distribution businesses. The Commission will review these costs to ensure that they are prudent and reasonable. The Commission will set separate control formulas for transmission and distribution.

An aspect that needs to be considered as part of the design of the control formula is the length of the regulatory period. In deciding the period of a price control formula, a trade-off must be made between productive efficiency (i.e. lowering costs), and allocative efficiency (i.e. keeping prices in line with actual costs) objectives, as well as short and long-term efficiency incentives. If the price control lasts for a long time, the regulated company will have a strong incentive to reduce its costs, since it will be sure of keeping the benefits for many years. By the end of the period, however, prices may be significantly above the company's costs, leading to allocative inefficiency and possible distributive concerns. Further, the company's sustainability could be endangered if the price control turns out to be too demanding. If the price control period is short, the regulator can ensure that prices are always close to the company's costs, protecting sustainability and allocative efficiency. The drawback is that the incentives for productive efficiency may be weakened if the review period is shorter. The Commission seeks comments from the industry on the appropriate length of the regulatory period for transmission and distribution services.

Comment is invited on:

- Whether incentives on construction costs should apply for pipeline investments subject to consent.

- Whether a CPI-X mechanism should be adopted for the regulation of other transmission and distribution costs.

- The length of the regulatory period for the price or revenue control formulas for transmission and distribution services.

5. THE DETERMINATION OF ALLOWED REVENUES

The allowed revenues of a regulated firm need to be sufficient to enable it to recover an efficient level of operating costs (including depreciation) and earn a reasonable rate of return on its assets. If allowed revenues are set too low, the company will have a reduced incentive to invest. If allowed revenues are set too high, the company will earn excess profits to the detriment of gas customers. Determining an appropriate level of allowed revenues is, therefore, an important part of setting gas transmission and distribution tariffs.

The Commission will approve separate revenue requirements for transmission and distribution businesses. The principles used to calculate the revenue requirement for both services are the same. The Commission seeks comments from the industry on five areas related to the calculation of the level of allowed revenues for transmission and distribution businesses:

- the appropriate approach to asset valuation;
- the treatment of depreciation;
- the estimation of an appropriate rate of return on assets;
- the treatment of operating costs; and
- how allowed revenues are calculated.

5.1. Asset Valuation

There are a number of different methods for valuing assets and each method may result in different values being placed on the same asset(s). The choice of asset valuation method, therefore, will affect the regulated company's allowed revenues. Asset values affect the profile of allowed revenues by impacting on both the return on the outstanding capital at any time and the return of the initial capital outlay over the lifetime of the assets.

Ideally, the method used to value assets should be objective, transparent and stable. Moreover, it is desirable to use a method of asset valuation that will provide efficient pricing signals.

There are different asset valuation methods including historic costs, indexed historic costs, replacement cost, optimised replacement cost and deprival value. Appendix A discusses in detail those methods. The Commission's view is that an indexed historical cost is the most appropriate approach for the valuation of transmission and distribution assets. This method values individual assets at their historic costs inflated according to a general price index such as the Consumer Price Index. The Commission also opted for this approach for electricity regulation, as it is both easily and objectively determined.

5.2. Depreciation

Formally, depreciation measures the decline in, or loss of, the value of an asset.[5] In a regulated setting, depreciation charges provide the means for the recovery of expenditures on a regulated investment. The costs of such investments are incorporated into the revenue target, and hence into regulated prices. Typically, these costs are recouped over the life of the asset.

Depreciation can be thought of either as:

1. an accounting approach to recovering the cost of a regulated investment; or
2. an economic measure of an asset's changing value.

A number of accounting approaches can be used to calculate depreciation, including:

- straight-line;
- front-loading;
- back-loading; and
- Sum Of Years' Digits (SOYD), amongst others.

Appendix A discusses the different accounting depreciation approaches and economic depreciation. The Commission proposes to use an accounting (as opposed to economic) method such as straight-line depreciation for transmission and distribution assets, as it is simple, transparent and objective.[6] This is also the method that the Commission has adopted in electricity regulation.

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5 Bonbright, J.C., Danielson, A.L. and Kamerschen, D.R. (1988) *Principles of Public Utility* Rates, Arlington, Virginia: Public Utilities Report Inc., p. 268.

6 As we explain in Section 8, because of the particular circumstances of IC2 a different depreciation regime may be appropriate.

5.3. Rate of Return/Cost of Capital

It is important for the long-term viability of a business that it is able to earn a reasonable rate of return on its assets. The reasonable rate of return, more commonly referred to as the cost of capital, is the risk-adjusted return required to attract future capital.

Generally speaking, the more risky the business, the higher the cost of capital, since suppliers of funds will require a higher return to compensate them for bearing greater risk. Maintaining an expected allowed return on capital in line with the cost of capital is the primary determinant of the business's financial viability. The nature of the regulatory environment is an important factor in determining the cost of capital.

The Commission proposes to calculate the cost of capital for the transmission and distribution businesses using the Weighted Average Cost of Capital (WACC) approach. The WACC is the most widely used method by regulatory authorities for calculating the costs of capital. This approach is based on the fact that companies can raise capital through either debt or equity. The relative returns required for equity and debt are different, because debt holders enjoy a prior claim on a company's earning stream and therefore face different levels of risk. Thus, the cost of capital for a company is a weighted average of the two rates of return, with the weightings determined by the relative levels of debt and equity in the company's asset base, or the company's "gearing".

The issues related to the calculation of each of the components of the WACC, i.e. the cost of equity, the cost of debt and the gearing, are discussed in detail in Appendix A.

5.4. Operating Costs

To calculate transmission and distribution allowed revenues, the Commission needs to assess the company's future levels of operating expenditure.

It is an objective of the Commission to provide incentives for regulated companies to operate efficiently. The question that arises is how to determine the level of efficient operating expenditure.

The Commission will thoroughly examine the transporters' proposed operating costs for transmission and distribution services. The Commission may compare those costs with similar companies operating in *similar environments*. Where there are differences in the environment of the activities, these must be taken into account, e.g. a company with a greater customer density may have lower costs than a company with a lower customer density. It may not be possible to identify all the different factors required to account for cost differences between companies, and even where it is possible it will be time consuming, especially where there are likely to be larger differences in environment (as will be the case for comparing companies in different countries.)

5.5. Calculation of Allowed Revenues

There are different ways of calculating the maximum revenues over a price control period including:

- Accruals approach – in which maximum revenues are calculated as the sum of operating expenditure, depreciation and return on capital;

- Cash flow approach – this is equivalent to the accruals approach, but calculates allowable revenues as equal to the business's allowable spend on operating expenditure and investment, plus the change in the present value of its assets;

- Multi-financial indicator approach – which uses a range of accruals-based and cash flow based financial indicators.

The Commission opted for the cash flow approach for electricity regulation, as this was considered the most accurate measure of the revenue a company needs to finance its activities. The Commission is minded to choose the same approach for gas transmission and distribution services.

Comment is invited on:

- The appropriate methodology for the valuation of transportation assets.

- The appropriate method of depreciation.

- The proposed method for the estimation of the transmission and distribution rate of return.

- The proposed method for the calculation of allowed revenues.

There are essentially two distinct and separate steps involved in the establishment of transmission and distribution tariffs. The first is the determination of the maximum revenues, which the regulated company will be able to earn over a specified period. The second is the determination of tariff schedules which, when applied, will yield the level of revenues. Section 4 and Section 5 above have discussed the broad framework that the

Commission will use for the first step for transmission and distribution services. The second step is the subject of Section 6 (transmission) and Section 7 (distribution) below.

6. TRANSMISSION TARIFFS

At present Ireland's transmission tariffs are calculated on the basis of 'Irish entry/postalised exit.' Shippers pay separate tariffs for bringing gas onto and taking gas off the system. The level of the entry tariff is determined by the cost of the infrastructure required for each entry point, while the postalised exit tariff is determined by the average costs of the onshore transmission system, i.e. all exit points pay the same tariff. The tariffs are made up of a capacity charge and a commodity charge that reflect a 90:10 capacity/commodity split.[7] As part of its current full review of the transmission charging regime, the Commission will review the current transmission tariff structure.

Going forward some aspects of the structure of transmission tariffs in Ireland will depend, to some degree, on the approach for defining capacity rights (e.g. point-to-point, entry/exit). For instance, in the case of entry/exit different charges can be set for the different entry and exit points and, in the case of point-to-point, it is possible to set separate tariffs for the use of different routes of the transmission system. Currently, the Commission, in consultation with the Gas Market Advisory Group[8], is considering the benefits and costs for gas customers of moving from the current point-to-point system to an entry/exit regime. Once a decision on this is reached the Commission will be in a position to provide detailed recommendations on how transmission tariffs should be calculated.

However, at this stage there are several areas of the design of transmission tariffs where the Commission would like to seek comments from the industry:

- Definition and allocation of transmission costs among different users;
- Classification of costs into fixed and variable components;
- Short-term service pricing principles; and
- Interruptible service pricing principles.

The rest of this section discusses each of these areas.

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7 Department of Public Enterprise, *General Directive concerning standard service pricing for gas transmission Entry/Exit at Inch. General Directive concerning standard service pricing for gas transmission on the Onshore Network. General Directive concerning standard service pricing for transmission between Scotland and the Republic of Ireland.* November 2001.

8 To assist the Commission in its review of the gas market arrangements, the Commission has established an advisory group, the Gas Market Advisory Group, to represent the views of the gas industry.

6.1. Definition and Allocation of Transmission Costs Among Transmission Users

A key area of designing transmission tariffs is the allocation of transmission costs to the different users of the transmission system. Cost-reflectivity requires that users pay for the costs that they impose on the system, so that users face the cost consequences of their usage decisions. Cost-reflective charges enhance efficiency because they send correct price signals to users who are making decisions about system usage and ultimately to the transporter about investment.

There are two main cost drivers for gas transmission pipelines (1) distance from the gas source, and (2) congestion. The reasoning behind the first is straightforward: more physical assets are necessary to serve a user further from the gas source. The second reflects that where peak demand threatens congestion increments in demand can raise costs by requiring more capacity.

In the case of distance-based charges, the allocation of costs focus on (1) determining which transmission costs vary with distance and which costs do not and (2) allocating distance-related costs to the different users based on each user's distance from the gas source and reserved capacity.

In the case of congestion-based charges, it is necessary to identify the *incremental* (or long-run marginal) costs that users impose on the system depending on their location. The calculation of the long-run marginal cost requires the calculation of the additional investment required to support a sustained notional increase in flow in different parts (or routes) of the transmission system.[9] However, marginal cost prices need to be scaled up or down so that the total revenues from those charges cover the transporter's revenue requirement. Unavoidably, some of the desirable features of the marginal cost pricing are lost through the scaling process.

Whether transmission tariffs should reflect distance or incremental costs or both depends on the physical characteristics of the transmission system. For instance, in transmission systems where there is a considerable amount of spare capacity, a cost-reflective tariff structure should focus on allocating past or actual costs to the different users based on each user's distance from the source and reserved capacity. In addition, in the case of systems with a well-developed secondary market for capacity rights, secondary capacity market prices take on much of the responsibility for signalling scarcity or congestion. That is, the secondary market reveals (to users and the transporter) the market value of the capacity. However, in meshed systems

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[9] In the UK, Transco uses this method to set exit capacity charges.

where the distance travelled by gas cannot be identified, it may be difficult to set cost-reflective distance-based tariffs.

The current Irish entry/postalised exit tariffs are not fully cost-reflective as there is an exit charge that is common to *all* exit points while the cost of transporting gas to different exit points is different (i.e. there are no location signals in the onshore system). Therefore, whether a shipper uses the transmission system to deliver gas from Moffat to Limerick or to Dublin, it pays the same *onshore* tariff.

The problem of having a postalised onshore tariff is that it could result in inefficient by-pass.[10] However, the risk of uneconomic onshore investment in Ireland is low, as the Commission has to provide consent for new onshore transmission pipelines and, therefore, could refuse consent to the construction of any new pipeline where it determines that the capacity of existing pipelines will adequately meet expected demand.

However, cost-reflective transmission onshore tariffs might still be desirable in Ireland from an economic point of view, as a postalised tariff involves cross-subsidies between the volumes that impose relatively high costs on the system and those that impose low costs on the system.

Some industry participants have, in the past, proposed a postalised entry tariff. These parties have argued that a postalised entry tariff would result in lower gas prices for all Irish gas customers. The Commission's concern is that a postalised entry tariff would mean that shippers using for example Inch entry point would subsidise those users using Moffat entry point. That is, Inch shippers would pay for assets that they would not use or do not provide any benefit to them.[11]

6.2. Classification of Costs into Fixed and Variable Components

The Commission proposes that the tariffs for firm transmission service should continue to be made up of two parts: a capacity charge and a variable (or commodity) charge. The Commission also recommends that the

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10 For instance, under a postage-stamp regime, it may be cheaper for a user located near the gas source to build its own transmission line by-passing the existing transmission system than paying the (high) postalised transmission tariff. This investment would be inefficient if the cost of building a new pipe were higher than the actual cost of serving this user by the current transmission system.

11 As explained in Section 8, the Commission recognises that in the case of IC2 it could be argued that the additional capacity of the IC2 provides some benefits (e.g. security of supply) to all gas users even if they do not use this asset and, therefore, all users may have to pay for this benefit. However, this argument only applies to IC2 assets and should not be confused with having a postalised entry charge.

capacity element of the tariff for firm transmission service should reflect those cost elements of providing the service that are fixed (such as the return on and return of the capital involved in providing the pipeline), whilst the variable element reflects those costs which vary as a result of the gas quantities shipped. That is to say, the transporter would be required to classify its transmission costs into fixed and variable costs. All transmission *fixed costs* would be allocated to *capacity charges* and all *variable costs* associated with transporting the gas would be assigned to variable *charges*.

This tariff structure will ensure efficient utilisation of the transmission system, as users will pay a price for their marginal consumption that is equal to the marginal costs that they impose on the system.

As it has stated during its review of the gas distribution tariffs for the 2002/03 gas year,[12] the Commission may consider a different charging regime for CHP sites.

6.3. Short-term Service Pricing Principles

In the Consultation Document on Market Arrangement Principles,[13] the Commission raised the issue of the Transporter being instructed to offer a one-month firm transmission service. The Commission is currently discussing with the Gas Market Advisory Group the desirability of the Transporter offering a one-month firm transmission service. However, the Commission considers it appropriate to discuss the pricing principles of this type of service in this Consultation Paper.

The Commission believes that a one-month firm transmission service would provide flexibility to shippers. However, the Commission also considers that this service should be priced so that it does not undermine the long-term firm transmission service (i.e. one year service). Based on this, the Commission proposes that the short-term firm service price:

- Should be no higher than the prices charged for authorised or unauthorised overruns;
- Should include a premium relative to the 12 month firm service; and
- The prices should reflect the different value of capacity at peak and off-peak.

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12 Cover Letter to BGE Distribution accompanying the 2002/03 Tariff Direction (Ref.:CER02143.pdf).

13 Consultation Document on Market Arrangement Principles. CER/02/117. 28 August 2002

6.4. Interruptible Service Pricing Principles

The Consultation Document on Market Arrangement Principles proposes that in addition to firm transmission services, the Transporter may offer interruptible transmission services. However, this service should only be offered if a reasonable proportion of the system capacity is booked. The actual proportion should be chosen such that there is a realistic chance of actual interruption at peak. Otherwise, users will rely on the cheap interruptible service rather than the more expensive firm one. Therefore, in order to decide the actual proportion it is necessary to determine the capacity and usage levels in different parts of the transmission system.

The Commission's view is that if capacity costs are collected through reservation charges from firm shippers, shippers that are able to accept gas on an interruptible basis should not be responsible for capacity/fixed costs since they do not cause any of these costs to be incurred. However, it is also possible to require interruptible shippers to contribute some proportion of the capacity costs of the system to the extent that the higher price of interruptible usage does not significantly discourage its use, i.e. the price elasticity of demand for interruptible service is low.

Whether and to what extent users taking interruptible services should also pay a capacity charge as a contribution to fixed costs depend on a number of considerations. Among these are the degree to which it is considered undesirable to discourage interruptible usage through higher than purely cost-reflective prices and whether the benefits of having interruptible load is to be left with gas users in the form of low variable cost-based prices, or whether there is a desire to allow the transmission company to capture the benefits of flexible pricing, to share with the firm service users that are bearing most of the cost of the capacity.

Comment is invited on:

- Whether it would be appropriate to reflect the different costs of the different parts of the transmission system in transmission tariffs. That is, whether transmission users should pay different transmission tariffs for the use of different parts of the transmission system.

- The desirability of having a postalised exit tariff in Ireland.

- The desirability of having a postalised entry tariff in Ireland.

- Whether the transmission capacity and variable components of the tariff should exactly match the transmission business' cost structure (i.e. the capacity charge should be levied to recover all the fixed transmission cost while the variable charge should be levied to recover only variable transmission costs) or whether a different capacity/variable split should be adopted.

- Whether there should be a different capacity/variable split for CHP sites, or whether there are other mechanisms within the tariff that could be used to encourage CHP installation and usage.

- The principles for pricing short-term firm transmission services.

- Whether interruptible shippers should pay only (1) a variable charge reflecting the short-run marginal cost of service or (2) they should also pay some of the capacity costs.

7. DISTRIBUTION TARIFFS

There are three areas related to the design of distribution tariffs where the Commission seeks comments from the industry:

- General distribution cost allocation method;
- Allocation of distribution costs among distribution users; and
- Classification of costs into fixed and variable components

These are discussed below.

7.1. General Distribution Cost Allocation Method

On 31 July 2002 the Commission issued a Consultation Document on two methods for allocating distribution costs to users for the calculation of *interim* distribution tariffs. These are the Statistical Cost Based Charging method and the Connection Specific Charging method.

- *The Statistical Cost Based Charging method* reflects volume consumed rather than system utilised. Application of this form of charging includes all gas users within a volume range up to 146,535MWh a year, irrespective of the system to which users are connected. Users with consumption up to this level would pay a distribution charge whether they were connected to the distribution or transmission system. Therefore, user charge is based on size, independent of location or system connection. Under this proposal, gas users of similar size and profile would experience similar gas transportation costs, irrespective of whether or not they are transmission or distribution connected.
- *In the case of the Connection Specific Charging method* the distribution revenue requirement is recovered from 'distribution-connected' users only. That is, no transmission connected users pays for distribution costs. Therefore two users with the same usage characteristics, but one connected to the distribution system and the other connected to the transmission system, would pay different total transportation charges.

Following a review of responses from interested parties to the Consultation Document, on 27th September 2002, the Commission directed BGÉ Distribution to adopt the statistical cost based method for the *interim* distribution tariffs to apply from 1 July 2002 to 30 September 2003. However, under the statistical cost based method, certain transmission connected users could face significant increases in their end-cost of gas, as they move from bundled contracts to more cost reflective ones. To mitigate the potential increase in the end-cost of gas to these users during the interim period, the Commission directed BGÉ Distribution not to charge distribution tariffs to transmission connected users but to charge distribution connected users a tariff as if it were still subsidized by transmission connected ones. This resulted in BGÉ Distribution facing a revenue shortfall of circa €4.5 million. Therefore, under the interim cost allocation methodology, distribution costs are paid only by distribution connected users but BGÉ Distribution was not allowed to recover all its distribution costs.

As part of the current review of distribution tariffs the Commission will need to approve a final cost allocation methodology for the calculation of the new distribution tariffs. The Commission's initial view is that the connection specific charging method is more appropriate than the statistical cost based method as it is cost-reflective (i.e. users are charged for the costs of the system that they use). Under this method all distribution costs would be paid only by distribution connected users and all distribution connected users would pay distribution tariffs.

7.2. Allocation of Distribution Costs Among Distribution Users

Distribution tariffs can vary for different types of distribution connected users to reflect the different costs that different types of users impose on the system. For instance, the Irish distribution system covers low and medium pressure pipes (i.e. generally 4bar or less, and some 7bar). There are at least three possibilities to allocate distribution costs to distribution connected users: (1) all distribution connected users pay the same distribution tariff (i.e. a postalised distribution tariff), (2) distribution connected users pay different distribution tariffs depending on whether they are connected to the upper or lower pressure tiers of the distribution system, or (3) the statistical cost based method is used to allocate distribution costs to distribution connected users based on the principle that large users utilise less of the distribution system than small users that tend to be connected to the extremities of the distribution system. The choice between the possibilities should be determined by the extent to which the costs imposed by different users of the distribution system can be separately identified and allocated to those users.

In addition, given that in Ireland parties other than BGÉ may be allowed to build and operate distribution networks in different distribution areas, it may be possible to put in place different postalised distribution tariffs for different distribution areas if differential costs justify this. That is, users in the same distribution area could pay the same distribution tariff though this tariff may be different from the distribution tariffs levied in other distribution areas.

7.3. Classification of Costs into Fixed and Variable Components

As in the case of transmission tariffs, the Commission recommends that the distribution tariff be made up of two parts: a capacity component and a variable component. The capacity component should cover all fixed distribution costs and the variable component should cover the variable distribution costs.

As discussed in Section 6, the Commission may consider a different capacity/variable split for CHP sites.

Comment is invited on:

- Whether distribution costs should be paid by distribution connected users only (i.e. the connection specific method) or by users with a volume up to 146,535 MWh (i.e. statistical cost based method).
- Whether there are other methods that would be appropriate for the allocation of distribution costs to users, and the benefits of these options.
- The appropriate method to allocate distribution costs to distribution connected users.
- Whether different distribution areas should pay different distribution tariffs.
- Whether the fixed component and variable component of the tariff should exactly match the distribution business' cost structure (i.e. the capacity component should cover all the fixed distribution cost and the variable component should only cover of the variable distribution costs) or whether a different fixed/variable split should be adopted.
- Whether there should be a different capacity/variable split for CHP sites, or whether there are other mechanisms within the tariff that could be used to encourage CHP installation and usage.

8. OPTIONS TO RECOVER THE SPARE CAPACITY COSTS OF IC2

8.1. Introduction

Users of the transmission system have expressed concerns about the impact of the costs of the second Scotland-Ireland Gas Interconnector (IC2) on transmission tariffs. While the Interconnector is unlikely to be needed in full for a few years, current Moffat shippers are already contributing to payments for IC2 through the Moffat entry tariff.

The issue arises as to whether current Moffat shippers should continue paying for the *spare* capacity costs of IC2 (i.e. Moffat shippers pay for capacity that they do not use), or whether there may be alternative sustainable options for the recovering of the spare capacity costs of IC2. This section examines possible options.

8.2. Background

In February 2001, the Government approved a request from the Department of Public Enterprise (DPE) to allow Bord Gáis Éireann to construct a second Scotland-Ireland Gas Interconnector. Construction work has now finished on the initial phase of the interconnector.[14] IC2 was gassed up in November 2002 and received a consent to operate in January 2003, allowing for commercial flow of gas.

The justification for the sanctioning of IC2 was based on the then perceived demand for capacity and on the security of supply situation at that time.[15] When the original Memorandum to Government concerning IC2 was submitted in 2001, it was anticipated that Ireland would have insufficient gas supply to meet projected demand in the winter of 2002/03. At this time it was believed that 'the Bord Gáis proposal for a second interconnector from Scotland was the only project capable of delivering gas to the Irish market in time to meet the expected demand in Winter 2002.[16] However, subsequent discoveries of indigenous gas[17], the closure of IFI (a major gas consumer) and the lack of the expected increase in power station demand have together considerably reduced the projected demand for gas through the interconnector.

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[14] Phase 2 will involve the extension, on a phased basis, of the Brighouse Bay compressor station to increase pressure into the sub-sea pipeline. This will be subject to market demand.

[15] Bord Gáis Éireann Annual Report & Accounts, 2001, pp. 4.

[16] Joe Jacob, the then Minister of State at the Department of Enterprise.

[17] The Corrib and Seven Heads fields.

It is important to note that IC2 will also serve the Isle of Man. The Commission notes that the costs of the link from the IC2 to Isle of Man will be excluded from BGÉ's revenue requirement for transmission tariffs in Ireland.

8.3. Options for Allocating the Spare Capacity Costs of IC2

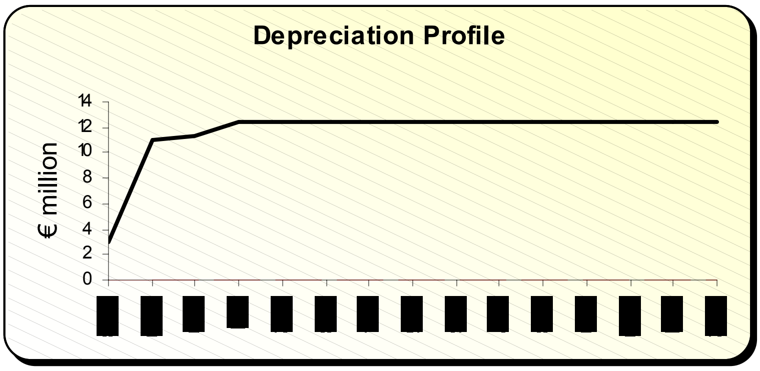
Option 1: Current Moffat Shippers pay for all the IC2 capacity

This is equivalent to the current situation whereby the capital cost of IC2 (excluding the costs of the spur to the Isle of Man) is depreciated on a straight-line basis over a 40-year period and these costs together with the return on investment and operating costs are allocated to those shippers transporting gas from Moffat.

Option 2: Current Moffat Shippers pay only for IC2 booked capacity and spare capacity costs are deferred

This option operates similarly to **Option 1**, in that the spare capacity cost of IC2 remains with Moffat shippers. However under this option, shippers would pay only for a proportion of the costs (booked/total) of the interconnector in line with current levels of demand. This option essentially defers cost recovery of the currently spare capacity in IC2 until it commences to be utilised.

This option could be implemented through the depreciation charge. For instance, a depreciation profile could be calculated as a function of the expected usage of capacity. The following figure illustrates this with an example. This example assumes that IC2 will start to be used in 2008. It is assumed that in 2008, 2009, 2010, and 2011 the share of booked capacity in total capacity will be 24%, 88%, 90% and 100% respectively. After 2011 IC2 is used at full capacity. The total IC2 investment costs are assumed to be equal to EUR 308.9 million in 2003. As the figure shows shippers start paying for the depreciation costs of IC2 in 2008 and after 2008 the depreciation charge increases with the increase in the usage of the interconnector. After 2011, when the interconnector is assumed to be used at full capacity, the depreciation charge is flat.



This option is arguably a more equitable solution than **Option 1** as Moffat users do not pay for capacity that they do not use. However, there are two main disadvantages of this approach:

1. There is a risk that the deferral could result in the BGÉ's revenues being insufficient to meets its ongoing operating expenses and obligations to creditors, in which case the approach would not be workable (or would have to be modified).
2. There is also the risk that, should usage not increase, this option would not only defer current charges but worsen it for future shippers. There is the risk that the deferral could result in future charges being so high that users are unwilling to pay the price, and opt instead to forego using gas altogether. This would be inefficient from an economic point of view.

Option 3: All Irish Shippers pay for IC2 through a Public Service Obligation

Under Section 21 of the Gas (Interim) Regulation Act, 2002 the Minister may, following consultation with the Commission, impose a public service obligation in respect of expenses incurred to promote, among other things, security of supply.[18]

In the light of the security of supply function fulfilled by IC2, it may be feasible to isolate the spare capacity costs in the pipeline and charge for this through a public service levy until the capacity ceases to be spare. This would mean that all shippers (not just Moffat shippers) in the Irish system would pay for the cost of the unused capacity on IC2. This would be consistent with the original justification for the construction of the IC2 (i.e. security of supply).

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[18] **21.**—(1) The Minister may, following consultation with the Commission and such interested parties as determined by the Minister, by order direct the Commission to impose on such classes of natural gas undertakings as may be specified in the order in the general economic interest, public service obligations which may include security, including security of supply and technical or public safety, regularity, quality and price of supplies, and to environmental protection.

Option 4: Storage

As IC2 may not be needed to any significant extend for few years, it has been suggested that (a proportion of) the spare capacity be sold as storage. Given that the pipeline is essentially connected to Ireland, Northern Ireland, the UK and the Isle of Man, there is potentially a large market for such a storage facility. This option would require further evaluation of its engineering feasibility and the likely demand for such a service, together with pricing options for the service. The revenue obtained for such service could be used to offset part of the total spare capacity costs of IC2.

Option 5: Dividing the costs of latent capacity at IC2/ Backup

This option operates similarly to a public service levy, but also recognises the demand for a back-up service among shippers of indigenous gas. With this option, the cost of the spare capacity at IC2 is distributed among all shippers in the Irish system. This would result in the raising of the onshore tariff for all shippers, although the Moffat entry tariff would decrease. In these circumstances, there would be no charge for any back-up service at Moffat, other than to cover any administration costs incurred. The service would be provided on demand to anyone who could prove a genuine operational need for the back-up service.

The Commission notes that this option was proposed and rejected in the context of the proposed fourth modification to the Transmission Code of Operations (Modification 4), concerning flexible capacity services at entry points[19]. The Commission notes that (1) the back-up service provided under this modification was not linked to IC2 but to the Moffat entry point in general and (2) this modification was only an interim solution that may need to be modified as a result of the review of the market arrangements. Therefore, the Commission would like to consider this option for the particular case of IC2.

As in the case of **Option 3**, this option recognises the importance of IC2 for security of supply. This security applies equally to all shippers, whether or not they use Moffat as their primary entry point. Equally, even shippers who do not use Moffat and who do not wish to purchase backup will benefit from the avoidance of system emergencies and blanket effects. However it is unlikely that this benefit will be large enough to justify the cost of this option on purely economic grounds.

Option 6: Using a lower rate of return for IC2

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[19] Transmission Code of Operations, Modification 4: Flexible Capacity Services at Entry Points (Ref.: CER/03/018, 27th January 2003).

Another possibility to minimise the impact of the IC2 spare capacity costs on transmission tariffs is to allow a *lower* rate of return on IC2 assets for a specific period. A lower rate of return could be used until the volume of gas flowing through IC2 corresponded to a benchmark figure. That is, under this option BGÉ transmission would only be allowed to recover a return equal to the cost of debt on IC2 until such time as the booked capacity of IC2 reached certain level (e.g. the volume anticipated when the investment decision was taken).

Option 7: Profile costs and demand over a period

Another possibility is to profile the cost per unit of IC2 over a long period. For instance, the revenue requirement for IC2 (return on assets, depreciation and operating costs) can be calculated over a 5 years period as showed in Table 8.1 below. Based on this a levelised IC2 cost per unit can be calculated (EUR 4.5/unit). However if a longer period is used (see Table 8.2), for example 10 years, the levelised IC2 cost per unit will be lower (EUR 2.2/unit). This Option is similar to **Option 2** in that the recovering of the IC2 revenue requirement is deferred until demand increases. For example, using the example in Table 8.2, the revenue requirement required over the first 5 years is EUR 50, but the actual amount recovered is EUR 24. However, in the last five years the revenue requirement is also EUR 50, but the actual amount recovered is EUR 76.[20]

Table 8.1

Year	1	2	3	4	5
Revenue Requirement (€)	10	10	10	10	10
Usage of pipe (units)	1	1	2	3	4
Cost per unit	10.0	10.0	5.0	3.3	2.5

Total revenue required (€)	50
Total flows (units)	11
Number of years	5
Tariff (€/unit)	**4.5**
Total revenue (tariff*units)	50

[20] For simplicity, these two examples assume a discount rate equal to zero.

Table 8.2

Year	1	2	3	4	5	6	7	8	9	10
Revenue Requirement (€)	10	10	10	10	10	10	10	10	10	10
Usage of pipe (units)	1	1	2	3	4	5	6	7	8	9
Cost per unit	10.0	10.0	5.0	3.3	2.5	2.0	1.7	1.4	1.3	1.1

Total revenue required (€)	100
Total flows (units)	46
Number of years	10
Tariff (€/unit)	**2.2**
Total revenue (tariff*units)	100

The same disadvantages identified for **Option 2** apply to this Option.

Option 8: Cap Moffat tariff

Another option is to cap the amount of IC2 costs paid by Moffat shippers and recover the remaining IC2 costs from other shippers. The Commission invites comments on how this cap could be determined.

8.4. Commission's View

While it is unlikely that any of the individual options discussed above would provide a complete solution to the issues raised by the spare capacity costs of IC2, it is possible that a combination of these measures may alleviate the burden now faced by Moffat shippers. The Commission invites comments on the options to deal with the spare capacity costs of IC2.

Comment is invited on:

- The most appropriate option or combination of options to deal with the spare capacity costs of IC2.
- Whether there are other options (besides those discussed in this section) to deal with the spare capacity costs of IC2.

APPENDIX A. REVENUE REQUIREMENT CALCULATION

A.1. Asset Valuation

As explained in Section 5.1 there are several asset valuation methods. This section discussed the main methods.

1. *Historic cost (HC):* This method values assets at their original purchase price. The principal advantages of this method are that asset values can be determined easily, because they should be available from published accounts, and objectively, as it relies on actual data. However, this method has the disadvantages that asset values may differ significantly from their economic value. For example, in times of inflation assets values will be understated and in times of technical progress they will be overstated. Given the longevity of assets in transmission and distribution activities, these disadvantages can be considerable.

2. *Indexed historic cost (IHC)* (also known as the current purchasing power method of asset valuation). This method values assets at their historic cost inflated according to a general price index (eg the Consumer Price Index). As with the historic cost method, indexed historic costs have the advantages of being both easily and objectively determined. This method also avoids the principal disadvantage of the historic cost method, that inflation leads to an understatement of asset values, by explicitly inflating asset values by a general price index. A disadvantage of this approach is that, in the presence of technological progress, asset values will still be overstated compared with their replacement value.

3. *Replacement cost (RC).* This method values existing assets at the cost of replacing them with one that provides the same services and capacity as the existing one, ie a *Modern Equivalent Asset (MEA).* This method has the advantage that assets are valued in terms of today's prices and reflect technological changes, ie replacement cost asset values closely reflect economic values which provides efficient price signals. However, a disadvantage of this method is that estimating replacement costs involves exercising judgement and, therefore, are less objective than the HC or IHC methods. Moreover, the necessary data may be more expensive to collect than historical cost data.

4. *Optimised replacement cost (ORC)***.** This is a variant of the replacement cost method. Optimised replacement cost can be thought of as what a new entrant (supplying the whole market) would have to pay to build the system on a greenfield site, assuming an "optimal" system (i.e., one which has no redundant assets). The use of ORC as a way of valuing assets allows an adjustment where, for example, the

service capacity of existing assets is in excess of current requirements, perhaps reflecting over-investment in the past. The ORC approach requires a greater degree of judgement on the part of the Commission than the simple replacement cost approach.

5. *Deprival value.* Deprival value is defined as the minimum loss the business would suffer if it were deprived of the asset. Were the asset to be replaced, its value would equal the replacement cost. If the asset would not be replaced, then the deprival value would be the greater of the net present value of expected cash flows from the continued use of the asset or the net realisable value of disposing of the asset, ie the recoverable amount. In other words, it is the minimum of an asset's replacement cost or its economic value. In a regulatory context, the use of deprival values is not feasible due to circularity difficulties (ie to set allowed revenues the regulator needs to know net present value of future expected cash flows, which are set by the regulator).

A.2. Depreciation

As explained in Section 5.2, a number of accounting approaches can be used to calculate depreciation, including:

- straight-line;
- front-loading;
- back-loading; and
- Sum Of Years' Digits (SOYD), amongst others.

The straight-line method amortizes the costs of assets through equal annual charges over estimated service lives. The back-loading method increases charges over time, while the front-loading method decreases depreciation charges over time. In the SOYD method the cost of the asset less any residual value is divided by the sum of the years' digits to give what may be termed a *unit* of depreciation. For an expected life of 5 years, the sum of the years digits (SOYD) = 5+4+3+2+1=15. In the last year of expected life, one unit of depreciation is provided for; in the next to last year of expected life, two units of depreciation are provided for; and so on. In the first year of an asset with an expected life of 5 years, 5 units of depreciation are provided for. Each of the accounting methods of depreciation described above is simple, transparent and objective. However, in using accounting methods of depreciation, there is no guarantee that the net asset value will reflect the economic value of the asset.

Economic depreciation measures the changing value of the assets. The value of an asset can be affected by factors such as technical progress, obsolescence and expected usage of capacity and these factors will be reflected in economic depreciation. One advantage of economic depreciation over accounting depreciation is that economic depreciation reflects the economic value of the assets, which implies a more economically efficient price level and, therefore, efficient usage. However, as many of the factors underlying economic depreciation can change (e.g. the rate of technological progress), the depreciation charge for an asset needs to be reassessed regularly, perhaps each year. The need to regularly reassess economic depreciation can create uncertainty. Moreover, the calculation of economic depreciation is liable to be less transparent and more subjective than accounting depreciation measures.

A.3. Rate of Return

As explained in Section 5.3, the Commission proposes to calculate the cost of capital for the transmission and distribution businesses using the WACC. This section describes the issues related to the calculation of each of the components of the WACC.

A.3.1. The cost of equity

There are a number of alternative approaches to estimating the cost of equity.

These include:

- *Comparable earnings.* Under the comparable earnings approach, the cost of capital of a regulated company is based on the returns earned by private companies with a comparable level of risk;

- *Dividend Growth Model (DGM).* The DGM relies on the equivalence between a company's share price and the present value of its expected future dividends to estimate the rate of return for a regulated company (this approach requires assumptions to be made about the rate of dividend growth); and

- *Capital Asset Pricing Model (CAPM).* The CAPM breaks the cost of equity down into two components: a risk-free rate; and additional return or premium for holding risky assets. This additional return is related to the "premium" earned on investments in the stock market in general, adjusted for the correlation between the stock market and the company's own returns.

The comparable earnings approach has the advantage of being the simplest of the above methods for calculating a regulated companies rate of return but, arguably, requires the application of the most judgement on the part of the regulator, which undermines stability and predictability. Both the DGM and CAPM are well supported by economic theory. However, CAPM is, arguably a more objective method in regulatory settings than DGM as CAPM uses the data defined for the market (e.g. the risk-free rate and the equity risk premium), rather than for the firm, as is the case for DGM (and which gives rise to a circularity problem).

CAPM has become the most widely established method for estimating the post-tax return on equity of regulated companies, outside of the US. The Commission is minded to estimate the cost of equity within the CAPM framework. The use of the CAPM requires the estimation of:

- *Risk free rate*: the expected return on a risk-free asset (or the "risk-free rate") is the price that investors charge to exchange certain current consumption for certain future consumption, ie the return on an asset that bears no risk at all. Although the risk free rate cannot be directly measured, the return on index-linked sovereign bonds is frequently used as a proxy. The principle decisions required in estimating a risk free-rate using index-linked sovereign bonds are: (1) the appropriate maturity of the bond to use; (2) the appropriate reference market; and (3) whether to use long-run historical averages of bond yields, or current yields.

- *Equity risk premium*: the equity risk premium is the difference between the expected return on the market portfolio and the expected return on a risk free-asset. The equity risk premium can be estimated using either: (1) the average differences between realised (ie historical) returns (on a proxy) for the market portfolio and realised returns on (a proxy for) the risk free rate (known as the ex-post approach); and (2) the difference between current observable expected returns on a proxy for the market portfolio and current observable expected yields on a proxy for the risk free-rate (known as the ex-ante approach). Under the ex-post approach, the equity risk premium is sensitive to factors including: (1) the choice of historic time period; (2) the choice of reference market; (3) the risk free-rate; and (4) the choice of averaging process.

- *Beta*. CAPM theory states that investors hold diversified asset portfolios and, thus, the specific risk associated with each company is "diversified away". An asset's return is therefore related only to the assets covariant risk with the market portfolio, that is, the degree of co-movement between the company's return and the market returns. In the case of BGÉ, the two principal considerations for estimating beta are: (1) as BGÉ is not listed, so beta cannot be directly estimated, what comparator companies should be used to proxy for BGÉ's beta; and (2) the time period over which the beta of comparator companies should be calculated.

A.3.2. Cost of debt

The cost of debt can be expressed as the sum of:

- the return required by investors to invest in a risk free investment; and
- the company specific debt premium, ie the margin over the risk free rate at which debt can be obtained by the business in question.

The cost of debt can be estimated by reference to the market based evidence on the cost of debt of comparator companies.

A.3.3. Gearing

Gearing is the ratio of debt-to-debt plus equity. Since the market returns on debt and equity vary, the gearing ratio has an impact on the level of the final WACC if the cost of equity and the cost of debt are different.

The Commission's aim is to allow the regulated business only the *required* cost of finance. For example, if the structure of financing is non-optimal, so that the cost of capital is greater than the optimal level, the extra cost might not be viewed as a required cost of finance as, for example, the company taking on more debt could reduce the cost. For this reason, the Commission is minded to estimate the WACC on the assumption of an efficient or 'optimal' level of gearing.