Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

TRANSMISSION AND DISTRIBUTION TARIFFS OBJECTIVES AND PRINCIPLES

Summary of Comments

June 2003

CER/03/142

Table of Contents

1. Introduction

On 19 March 2003 the Commission published a consultation document entitled 'Transmission and Distribution Tariffs Objectives and Principles' (CER/03/060). This paper is a summary of the comments received in relation to the consultation.

The document is structured in the same manner as the aforementioned consultation paper. Specifically:

- Section 2 summarises comments relating to the appropriate form of regulation for the transmission and distribution businesses;
- Section 3 summarises comments relating to the calculation of the transmission and distribution revenue requirement;
- Section 4 summarises comments relating to the objectives and principles for setting tariffs for different transmission services;
- Section 5 summarises comments relating to the objectives and principles for setting tariffs for different distribution services; and
- Section 6 summarises comments relating to the different options to deal with issues surrounding the Second Scotland-Ireland Interconnector (IC2).

2. Form of Regulation

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

Approve

Ten parties agreed that incentives on construction costs should apply for pipeline investments subject to consent. While these parties approved with the approach in principle, they made the following points:

- At present Bord Gáis Éireann ("BGÉ") Transmission & Distribution is allowed to include all capital expenditures in its regulatory asset base and has no incentive to minimise these expenditures.
- As with any such form of incentive arrangement, close scrutiny of the target estimate/approved cost would be required.
- One party believes that a decision is needed on whether incentives should be made on the basis of appropriate benchmarking to assess construction costs of pipeline investments.
- It was queried as to what stage in the development process would the "estimated" costs be set. Projects requiring consent typically consist of a design and tendering phase and a construction phase. At present the Commission is closely involved in this process and is well aware that different projects may go through any number of revisions before a final consented design is achieved. Therefore the details of how benchmark costs would be determined during this process would need to be discussed with the Commission, to ensure that provisional project information was used as a basis on which to set realistic project benchmarks.
- It was suggested that payment from delivering a project below the target price be given as a one-off payment and not included in the regulatory asset base.
- Given contracting practices where developers and construction contractors agree to share, where appropriate, either savings or cost overruns, it is not obvious as to how any savings or cost overruns are to be shared with gas customers.
- The Commission's proposal could be further adapted to also reflect deviations between the demand profile used to justify the need for the pipeline and actual usage during the operating life of the pipeline. For instance, the Commission could use both the expected demand and target construction cost to calculate a tariff. If the party building the pipeline manages to earn more than the allowable revenue, it would share the surplus with gas customers. However in the event that the actual revenues are less than the allowable revenues, the party building the pipeline would bear most of the shortfall.
- Another party believes that all system reinforcement should be tested rigorously against criteria of realistic demand forecasting and capacity planning - cost targets should be set against appropriate and relevant benchmarks and the developers return should be set to

provide incentives for cost-efficiency and should be vulnerable to poor investment performance or cost control.

- One party would be concerned if any incentive regime were to expose the pipeline business to significant risks that are not controllable or if the expected rewards were outweighed by the downside. The key is that only controllable costs should be subjected to incentive regimes. As the Transporter will typically contract out the construction of all major projects through a competitive tendering process, they are not controllable in that the competitive market determines to a large extent what construction costs will be incurred. As such the Transporter can only be expected to control its project management costs and some part of the costs incurred through contract variations. Thus the incentive scheme should be implemented only with respect to its own project management costs plus potentially some element of contract variation costs.
- Assuming that a system of incentives for controllable costs is devised without unduly exposing the transportation company to uncontrollable risks, the Commission must also ensure that risks and rewards are balanced. The regime must ensure that the expected rate of return properly reflects the risks created by introducing variance in returns and benchmark costs in the application of the incentive system properly reflect the distribution of costs. A purely symmetrical regime is unlikely to achieve the latter as there will inevitably be a small number of projects with very large cost over-runs (due to unknown uncontrollable factors at the design stage), whereas there is no likelihood of equivalent substantial cost savings. Given that the distribution of costs is asymmetric, the incentive regime must reflect this if it is on average to cover costs and compensate for risk exposure. In addition, the possibility of significant uncontrollable cost-overruns suggests that a cap on the risks to which BGÉ is exposed on any one contract would be appropriate.
- Clarity would be needed on the criteria to be used by the Commission in deciding which projects to submit to the incentive mechanism. Many small investments require consents, and a de minimis rule may therefore be needed.

Disapprove

One party disagreed with the concept of incentives to reduce construction cost, on the following basis that:

- The simplest approach is to let the Transporter tender for work and verify that they have performed professionally in their efforts to place work contracts at the best price. In addition this work should be benchmarked against other pipeline operators by an independent third party expert. If this were done there would be little or no concern in the gas industry. If one sets a “target” cost, and this “target” is set equal to the construction company’s estimates this might not be the most efficient mechanism and may encourage price distortion. Also a general fact of doing business is that if one gets a number of estimates for work initially, by the time the deal is finally agreed and the order is placed one will have used all means possible to secure the most attractive commercial deal and thus generally one will have negotiated a better deal than the estimate outlined.

- To incentivise a company to do something that should be normal seems incorrect and highly unnecessary. It should be a corporate obligation for the Transporter to do the best job cost-effectively, as it generally is in most commercial companies. In industry for example incentives typically are used as a reward for cutting historic operational costs, shortening average service times, attacking accepted work practices to get improvements, etc – not for something like pipeline procurement and installation at best value which is in fact the company's basis job.

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

Approve

Ten respondents supported the idea that CPI-X should be used for the regulation of other transmission and distribution costs, with the following specific comments made:

- CPI-X should be adopted with X set at 2%, the rate applicable in the UK.
- If CPI-2% were applied to controllable operational costs including business overheads, this would be commensurate with the normal level of economic efficiency expected in commercial activities.
- The CPI-X mechanism is appropriate provided that it is consistent with a realistic view of what is controllable and that the allowed rate of return properly reflects the additional variance in returns that such a mechanism may create. A comparatively small proportion of the Transporter's total cost base is controllable in the short run. For example a large proportion of the Transporter's cost base is accounted for by fixed investments, the value of which has been agreed with the regulatory authorities, and the recovery of which is already determined. In addition a substantial proportion of operating expenditures are not controllable – for example maintenance contracts let through a competitive tendering process or Local Authority rates.
- The Commission also discusses the issue of whether any CPI-X regulatory formulae should provide a price cap or a revenue cap. Volume-related revenue drivers should ideally match the cost drivers actually faced by the pipeline business. If they do not the regulated company will be exposed unnecessarily to risk because volume changes would cause revenue changes that are not matched by volume-related cost variations. The costs of uncongested gas transportation networks are hardly affected by volumes transported over the period likely to be covered by any price control. Roughly speaking, costs are partially fixed and partially driven by the number of connected customers, but not by throughput (although over the longer term, costs will vary with the peak and total use of the system). Therefore a revenue cap would better reflect the cost drivers the company faces than would a price cap.

Disapprove

Two respondents did not totally support the CPI-X formula, with the following points being made:

- One party stated that it does not support the idea of a pure incentive regulation as it appears to be inappropriate in the Irish context at present. Cost of Service regulation with some incentivisation might be the better option in an opening market like Ireland where a great deal of the facts remain unclear. If there is comfort in the knowledge that all the true facts are known and that an incentive regulation may be appropriate then at this time.
- A pure CPI-X formula is not suitable for any business which has not got a predominantly consumer/retail emphasis. The Transporter buys mechanical equipment and pipework, the cost of which has not changed to any large extent in years, thus making CPI-X inappropriate. In addition the Transporter's other costs are most likely personnel and systems. It could be argued that salary costs and systems costs are not truly linked to CPI as they are quite stable in price. Thus the CPI is running at a higher rate than any increase in the costs associated with the Transporter's business and should not be used. However the party would not object to some of the Transporter's costs having this index if it is deemed by CER to be appropriate, but would not support this index applying to all "other" costs. Overall "other transmission and distribution investments and costs" should be split into at least two areas (i) pipelines and equipment linked to a relevant index other than CPI and (ii) other expenses, which could operate on a CPI – X index.
- CPI is not adequately reflective of fuel economics. In Ireland the basket of goods is significantly impacted by movements in the price of cigarettes, alcohol and mortgage costs. A more appropriate basket of goods may need to be selected to benchmark fuel pricing against. More generally, the party does not support the – X concept, provided it is accepted that consistently poor performance could result in a negative result.

2.3. The length of the regulatory period for the piece or regulatory control formulas for transmission and distribution services

1/2 Years

One party stated its preference for shorter periods of one to two years, though longer periods may become more appropriate in future years.

Another respondent noted that transportation costs and charges for the existing transportation system are well known and defined. However it assumed that with the addition of significant new infrastructure, future cost levels are not as clear, while similarly the distribution system is in some state of flux. Therefore the price control for both transportation and distribution should initially be for a period of two years with the intention that a four-year cycle be adopted once the current system changes have bedded in.

3/4/5 Years

One respondent stated three years as the appropriate review period, allowing for some certainty and enabling the Transporter gain from any efficiency gains made.

One party stated that the review period should be three years in length. An annual review is too frequent to enable the Transporter to gain from any efficiency programmes that are launched and, hence, may inhibit any such action. The party strongly recommends that a three-year review period is adopted to cater for such major changes that may significantly adjust pricing structures and cause price shocks for the customers.

One party suggested the length of the regulatory period should be set at no more than three or four years, with the option on the CER to step in and implement change in the event of unusual circumstances.

A respondent raised the issue in relation to the length of the review period that a problem can be the regulated body delaying investment in the early part of the control in order to improve control, causing problems where investment is needed earlier. On the other hand if the period is too short the review process can become almost constant, resulting in volatility. Given these two issues a four-year period was recommended.

Two parties believed that a regulatory review period of between three and five years would be suitable. One party believed that this is necessary as due to the nature of the tariff structure, any unexpected events that effect the quantity or timing of changes to the projected supply or demand for gas can cause significant pricing shocks. In addition, a levelised tariff based on at least ten years is appropriate. This is particularly the case given the exceptional circumstances whereby low utilisation of certain transmission assets for significant periods of time is envisaged. A fair allocation of costs between current and future users of the system must be achieved.

Five years was suggested as the period by one party, given that this is the case in the UK and this seems to operate well. It is essential that the time period does not restrict market penetration and growth.

Greater than 5 Years

One party stated that the interval between reviews should be long enough to satisfy the objectives of stability and predictability and should be not less than 10 years unless some unforeseeable changes of circumstance intervene.

No Exact Period Given

One party stated that the Commission, in seeking to minimise tariffs for final customers in the long run, should strike to achieve the appropriate balance between providing incentives to make cost savings and limiting risk. Whatever regulatory regime the Commission chooses to put in place, it may have teething problems and it is therefore prudent to have an initially short period between price controls. In addition the party believes that the majority of the Transporter's costs are uncontrollable in the short term. If such costs are included in the cost base to which CPI-X is applied, this also points to the need for a reasonably short period, perhaps two years or so, so as to avoid the avoid the risk of the transporter's financial position becoming a problem while awaiting the price review to recompense for uncontrollable costs. Alternatively, the Commission could limit the scope of CPI-X regulation to exclude uncontrollable costs allowing the Transporter to recover these as and when they occur. However, if a short review period is implemented, to avoid destroying the incentive for cost savings, the period of savings retention should not necessarily be equated to the length of the review period. Decoupling the review and retention periods also makes it possible to avoid creating any differentials in the incentives for cost savings at different times during the price control period. If, for example, the price control simply removes any excess of revenues over costs in the last year of the period, it becomes significantly more valuable to reduce costs at the start of the period than towards the end. Such periodicity distorts incentives and can result in work being undertaken when it is advantageous to do so because of regulatory rules, rather than when it is in the best interests of system users. Mechanically, it is straightforward to design a regime that allows a constant period over which the rewards for out-performance are retained by the firm. The Commission could track the dates of cost reductions and set allowed revenue so that it follows the path of costs with a constant lag. However, there must also be a firm commitment against regulatory opportunism, as the Commission always has the ability at price reviews to set targets for the next period that (for example) might be tougher if the regulated company were currently receiving rewards for past good performance. Without a clear structure for price-setting, and an audit trail for the determination of efficiency targets, there may be a suspicion that the regulator is "allowing" the full recovery of cost savings with one hand, while taking those rewards away with the other. It is essential for confidence in financial markets that the Commission maintains a reputation for commitment to rewarding fully any out-performance against reasonable expectations.

3. The Determination of Allowed Revenues

3.1. The appropriate methodology for the valuation of transportation assets.

Indexed Historical Cost

Four respondents expressed a preference for the indexed historical cost method. One, however, said that since this method does not account for technological progress, the indexation should be frozen after a period of years. Another said that while the method does not take account of gas-specific technical progress, CPI does take account of economy-wide technical progress. Furthermore, unless the Commission proposes to apply a physical, as opposed to financial, capital maintenance approach to determining allowed capital costs, this concern does not create any reason for rejecting the indexed historical cost method. The respondent went on to say that the alternative methods would create greater risks and jeopardise tariff stability.

One respondent said that if this method is used, the CPI is not a relevant index for pipework/steel construction materials so a more relevant index should be used.

Historical Cost

One respondent said that historic cost is the most prudent, simple, and objective method of asset valuation.

Replacement Cost

One respondent supported the replacement cost method, saying it reflects the appropriate value to the users of the system. The respondent said that the method factors in advances in technology developed since the time of construction and avoids penalising end users from any inefficiencies that arose at the time of construction.

Optimised Replacement Cost

Three respondents suggested that optimised replacement cost is the best method. All three said that BGÉ has a number of under-utilised assets so the asset valuation should reflect that. Asset valuation could increase as asset utilisation increases.

3.2. The appropriate method of depreciation.

Straight-Line

Eight respondents expressed a preference for straight-line depreciation, with some saying that it is simple, transparent and objective

Other Options

One respondent suggested using the depreciation profile to make the current approach of levelising transmission tariffs more transparent. At present levelised tariffs result in under-recovery of the allowed rate of return in the early part of the ten-year period over which the levelling calculation is applied, balanced by an over-recovery in the later part of the period, allowing full recovery in the long term. However, the need for over-recovery to compensate for prior under-recovery is not recorded in any transparent accounts as a credit due to BGÉ. The regulatory depreciation profile could, without affecting tariffs, be used to create such transparency, increasing investor confidence.

Another respondent suggested profiling depreciation to more closely match asset utilisation.

Depreciation Period

One respondent said that depreciation against realistic asset life should be applied, while three respondents suggested increasing the asset lives for transmission pipelines from 40 to 60 years. One went further to say that long-term energy demand and supply scenarios suggest that depreciation over 60 years is indeed feasible.

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

WACC

Eight respondents agreed that the weighted average cost of capital method is most appropriate. Two parties suggested a real, pre-tax return of 4.8% based upon estimation of the various elements in the CAPM model. One respondent said that the WACC calculation should treat BGÉ business units as separate entities, e.g. that the WACC for transmission assets should be reflective of the pipeline business of BGÉ Transmission only, and take no account of the other parts of BGÉ, such as supply and CHP. Another respondent emphasised that the figures selected for use in the CAPM model should reflect the commercial and regulatory environment in which BGÉ operates. In particular, any move to a more incentive based scheme, such as CPI-X, creates additional risk for BGÉ which should be reflected in the choice of an appropriate beta and perhaps also in its choice of debt premium.

Other Suggestions

Other suggestions relating to estimating the rate of return included:

- That benchmarking should be applied against comparable risks and rewards in other commercial gas markets;
- That any available advantage or subsidisation in terms of cost or access to capital should be passed to gas consumers. For example, the WACC should recognise any advantage achieved as a result of government guarantees to BGÉ in financing its capital programme;
- That the rate of return be linked to prevailing wholesale market interest rates at the beginning of the gas year period plus 2%, reflecting the low risk of a monopoly service provider with a guaranteed regulated income and low cost of capital.

3.4. The proposed method for the calculation of allowed revenues.

Cash Flow Approach

Six respondents supported use of the cash flow approach, with one going on to say that it is consistent with the principle of ensuring that the Transporter can finance its business.

Accruals

One respondent suggested that the accruals method of calculation might be a more prudent approach.

Other Comments

One respondent said that it is not entirely clear how the determination of allowed revenue under the three approaches proposed would vary. Whatever method is adopted, the present value of revenue must equal the present value of costs, and the cash-flow implications should not put the financial position of BGÉ at significant risk, particularly since this may increase the overall cost of finance (and therefore the total costs to be recovered).

3.5. Operating Expenditure

A number of respondents advocated the use of benchmarking to compare BGÉ's operating costs for both transmission and distribution businesses.

4. Transmission Tariffs

4.1. 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. Or should the exit tariff remain postalised?

Postalised

Nine respondents supported remaining with the current regime with respect to exit charges, where they are postalised. Many gave the reason that, given the size of Ireland, separate exit charges would be overly complicated. Other arguments given against different charges for different parts of the transmission system include:

- That users could face large exit tariff changes when a production field depletes, in conflict with the Commission's objectives of a sustainable, stable and predictable tariff regime;
- That it would be discriminatory by location, discouraging industry in different regions;
- That it would cause a concentration of industrial and power generation in certain (cheaper) locations, impacting both socio-economically and on the electricity system;
- That long run marginal cost pricing (if it were used to determine the different charges) is only relevant when assets are fully utilised, and not when there is spare capacity on the system (where cost differentials between different points will be low);
- That the anticipated system layout, with a ringmain and three entry points, means any system would be complex to design and implement;
- That existing customers have little ability to respond to locational signals, and given BGÉ's deep connection policy, it is dubious whether any benefit would be obtained by giving locational signals to new users;
- That there would be the possibility of perceived or real discrimination between users;
- That load lost through higher charges would be less than the load gained through lower charges, disadvantaging all users;
- That competition would not be on a 'gas to gas basis' but a 'gas and tariff' basis; and
- That is has previously been agreed that that zonal pricing is not appropriate.

One respondent said that any adverse effects caused by postalised charges are unclear.

Locational

One respondent gave tentative support to having different tariffs for different parts of the system, contingent upon locational tariffs not making gas uncompetitive relative to oil in certain areas, switching people off gas to the detriment of all gas users.

Other Comments

One party voiced support for the "Geographic Equalisation Fund" proposed by the Brattle Group in its reports for the Department of Public Enterprise published in 2000. The respondent said that this fund provided for a postalised onshore tariff while, at the same time, recognising and accepting the principle of cost reflectivity.

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

Not Postalised

Seven respondents did not support the introduction of a postalised entry tariff. Arguments given against a postalised entry tariff include:

- That tariffs should be cost reflective;
- That the current regime promotes indigenous exploration and hence the benefits of indigenous gas supplies, encouraging producers to locate near to the market (enhancing security of supply);
- That postalisation would create a situation that is economically inefficient as cross-subsidisation would occur between entry terminals – effectively a levy on indigenous producers to be used for the purpose of subsidising the cost of importing a competing product;
- That, by way of illustration of the folly of postalised entry, a non-discriminatory postalised entry charge would have to include all onshore and offshore transportation assets, including those of producers, raising the tariffs even further;
- That if the principle of postalisation is followed for any future electricity interconnectors, Irish power generation would be uncompetitive relative to UK generation, decreasing demand for gas, and increasing gas tariffs even further; and
- That investment decisions have been made under the current regime, so moving to postalised entry would indicate a serious risk for potential upstream investors.

One respondent pointed out that, based on marginal costs, the Inch entry point (the only congested entry point) should have the highest tariff, with Moffat the lowest. The current arrangements give the opposite outcome, increasing the marginal price of all gas in Ireland.

Postalised

Ten respondents supported a move to a postalised entry charge. Arguments given for a postalised entry tariff include:

- That it would deal with the issue of spare capacity costs in IC2 – the interconnectors provide security of supply for all (Irish production will vary but the need for the interconnectors is constant) and so should be paid for by all;
- That it would reduce the price for gas paid by end users in Ireland;
- That it would ensure a positive competitive market between shippers of imported and indigenous gas to Ireland, removing the premium currently being given to producers. Also, only large players can buy forward from producers and gain the advantage of the lower entry tariffs – postalisation would level the playing field; and

- That the current regime is designed to encourage efficient expansion of the system. However, with IC2 built, there is no longer a requirement to promote efficient expansion.

4.3. 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.

Exact Correlation

Five respondents agreed that the 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 commodity charge should be levied to recover only variable transmission costs). Three of those respondents pointed out, however, that having a higher weight on the commodity element would incentivise the Transporter to encourage more use of gas. One pointed out that such a split would have adverse impacts on low load factor users. Another respondent said that the current split is widely used internationally and is consistent with the transmission cost structure.

Other Comments

One respondent advocated a lower split (50:50), which would attract peaky loads that would not otherwise use gas.

One respondent said that the Commission should not be prescriptive about the capacity/commodity split, but allow BGÉ to design tariffs with a variety of splits to encourage loads of any shape, provided they cover their marginal costs and make of contribution to the fixed costs of the system.

4.4. 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.

Three respondents said that tariffs are not the proper vehicle by which to incentivise CHP installation and usage. CHP could be supported by explicit subsidies outside of the gas tariffs.

One respondent welcomed any moves to encourage CHP.

Another respondent would only support a special arrangement to encourage CHP if all of the output of plant is to be consumed within the facility attached to the CHP unit.

Yet another respondent would support specific CHP tariffs provided they encourage load that would not otherwise be economic, they cover marginal costs and make a positive contribution to the fixed costs of the system, and eligibility for the tariff is defined sufficiently tightly that they do not become a route whereby other loads avoid the normal tariff. The respondent suggests that there could be a reduced tariff with a seasonal restriction targeted at the time of year when CHP would not otherwise be economic.

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

Three respondents stated that they agree with the Commission's proposals set out in the consultation document.

A number of respondents were concerned that a short-term service could result in a flight from annual booking, undermining the 12-month tariff. One of those suggests that the (provision and) pricing of any short-term service should therefore be left to the secondary capacity market.

Two respondents said that capacity services should be charged for on a cost-reflective basis and not by reference to a notional perception of value, whereas two other respondents said that any service should be priced on a value-related basis. One of those said that prices should reflect the different value of capacity at peak and off peak periods, while the other said that pricing could either by reference to seasonal values or by auction.

4.6. 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.

Three respondents said that interruptible shippers should make some contribution to fixed costs, with one of those saying that that contribution should be based upon seasonality factors. However, two respondents said that such a tariff should be based upon short-run marginal costs. One respondent said that in the long-term it should be charged at short-run marginal cost. But in short-term, with significant spare capacity on the system, it may be appropriate to have a capacity element.

Two respondents said that the (provision and the) pricing of any interruptible service should be left to the secondary capacity market, with one pointing out that the UK is moving away from offering interruptible capacity.

Two respondents highlighted a concern that cheaper interruptible capacity could become a substitute for firm service.

One respondent said that the pricing of interruptible capacity should reflect the risk that the shipper faces of interruption and should therefore be priced at a suitably lower level.

5. Distribution

5.1. 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)

Connection Approach

One party supported the connection specific approach, on the basis the use of the 146GWh threshold to decide who should pay distribution tariffs is arbitrary and unpredictable for customers, while it is not cost reflective for transmission users to pay for distribution infrastructure they do not use.

Another party supports the connection method, stating that any other would be grossly inequitable, given the historic context of connection to the system. Virtual transmission connection could be considered for larger distribution customers.

Another respondent stated that the statistical approach is discriminatory and distorts the TPA market - connection is the appropriate way of apportioning costs.

Another party stated that the connection specific method is the most appropriate and it would be highly inappropriate for transmission-connected customers to contribute to the cost of distribution system assets. Similarly a transmission-connected customer stated that it would take exception to it being required to pay a distribution charge. Likewise another party stated clearly that distribution services should not be subsidized, either directly or indirectly, from transmission capacity/commodity charges.

Statistical Approach

One party stated that to avoid discrimination between similar size load customers, the statistical cost based method should apply. However if the connection approach is used then the CER needs to ensure that new connections are not made to the transmission network as a means of avoiding the distribution tariff.

Another party stated that the statistical approach is more equitable and efficient than the connection approach, using the following points: (a) Whether users are connected to the transmission or distribution system is based largely on historical accident and therefore requiring similar users to pay different tariffs is inequitable and may distort competition generally; (b) In addition the connection-based approach provides a strong incentive for customers to bypass distribution, even if the total cost to the system of doing so is greater than the cost of connecting at the distribution level, leading to higher overall tariffs; (c) Another perverse incentive under the connection approach is that the transporter itself may faces an incentive to design and build the system to limit customers' options for bypass, if this charging method is retained. Under some forms of incentive regulation, it could raise more revenue if it built the system to prevent bypass rather than in whatever configuration is most efficient.

5.2. Whether there are other methods that would be appropriate for the allocation of distribution costs to users, and the benefits of these options.

One party suggested that an alternative to the statistical method includes one based on a probabilistic approach to which distribution assets a load is using.

Another party stated that given Ireland does not have a highly complicated gas system, the connection is the most clear, easy to implement and operate, fully transparent and objectively verifiable system.

Under a statistical method, another party stated that there may be a case for restructuring distribution tariffs to include a site charge, but with a concomitant reduction in other charges.

5.3. The appropriate method to allocate distribution costs to distribution connected users.

Favours Postalised

One party favours the use of a postalised regime as an equal and fair mechanism for the charging of costs. While the argument may be made that this mechanism would not be cost reflective in terms of the different sized users on the system, the respondent believes that it may also be argued that the larger number of smaller users end up paying for the largest proportion of the costs, which may not be reflective of the actual costs incurred in the pipeline development. This inequity would not be resolved through the use of allocating costs through the use of either pressure methodology or the statistical cost method. While the statistical approach may seem to allocate costs to the appropriate customer category, it ignores the original reason for the construction of the pipeline.

Favours Statistical

One party recommended the statistical cost based method as this is in line with the principles of cost reflectivity, transparency and predictability, based on the principle that large users utilise less of the system than small users. In a similar vein another party stated that relative tariffs should be based on customer characteristics, not upon the precise mix of assets directly used by an individual customer.

Favours Load Factor

One respondent stated that there should be some form of differentiation between customers based on their load factor, with higher load factor customers paying less per unit of capacity given that they are more efficient in their usage of gas. Such a charging regime could be applied throughout Ireland or could deal with local areas with local costs. This system could be applied in load factor bands and would have the benefit of giving the right signals to gas users to encourage increased gas usage and higher load factors to the benefit of both gas users themselves and the gas community as a whole.

5.4. Whether different distribution areas should pay different distribution tariffs.

Postalised

One party believes that the subdivision of charges between different areas seems to overcomplicate the mechanism for charging, as well as discriminating users on the basis of their location. For a transparent and non-discriminatory approach to pricing then the use of a single charge seems the most prudent.

Similarly one party believes that due to the relative small size of the Irish gas market a distribution gas tariff regime which supports different distribution tariffs for different distribution areas seems very much an over complication. For new gas users in new gas areas such a regime may also discourage them from opting to burn gas as they will pay higher prices. The need for locational signals in the distribution system is not seen as a priority in Ireland at the current time. Likewise another respondent opposed introducing different distribution tariffs for different areas because creating a differential between distribution tariffs paid in different areas is likely to reduce the rate of growth of gas demand. This would result in unit costs, and therefore tariffs, being higher than otherwise they would have been. Differentials would also complicate marketing by the transporter aimed at increasing demand.

5.5. 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.

Exact Correlation

One party favours the division of capacity/commodity split in the same proportion as fixed/variable costs. The calculation of fixed costs need to be the same as the balance sheet calculation, with items like labour costs etc being defined as variable costs. Another party stated that the fixed and variable charge split should reflect international practice and be consistent with the distribution cost structure. A justification for changing this basis is not apparent. Any change in the fixed and variable charge split would have to be arbitrary and thus would be difficult to avoid significant real or perceived discrimination against many users or classes of users.

80:20 Split

One party believes that due to the typical load factor of gas users in the Distribution System being lower than that in the Transmission System there is argument to suggest that a lower capacity component should be applied. However one must be conscious of the transporter's guaranteed revenue base. Hence the capacity/commodity split in the region of 80/20, which was previously put forward by the CER, seems reasonable.

Flexible Approach

One party's position with regard to the capacity/commodity split in distribution is as follows: The distribution network generally has spare capacity for some but not all of the reasons as transmission (i.e. principally lumpy investment in young and growing system). Given this spare capacity, the marginal costs of meeting peak demands are much lower than in a mature system. As with transmission, however, the effect on the marginal costs of off peak commodity demand is much less marked. Therefore, again if the 90/10 split is appropriate to a mature system generally in capacity balance, the ratio of marginal costs on the Irish distribution system at present is likely to put relatively less weight onto the capacity element and more on to the commodity element. However the party stressed that commodity marginal costs are no higher in absolute terms on a system with spare capacity - actually they too will be lower. There is the situation in which marginal costs are lower than any corresponding tariffs likely to achieve a reasonable contribution to allowed revenue recovery and the issue is how to structure tariffs to encourage the use of the system, both capacity and commodity, that would arise if tariffs could have been set at marginal costs. To do this it is desirable that the transporter should have the freedom to design distribution tariffs with a variety of capacity/commodity splits to encourage loads of any shape provided they cover their marginal costs and make a contribution to the fixed costs of the distribution system. As such the respondent urged the CER not to be unduly prescriptive about the 'correct' capacity/commodity split, rather to allow any tariffs that encourage new loads making a contribution lowering the cost of distribution for all users.

5.6. 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.

Different Split for CHP

One party believes that the capacity/commodity split should be lowered to 50/50 to encourage gas demand onto the system. Another respondent recognised that there may be scope for discounted tariffs for genuine CHP sites, where the introduction of such tariffs would lead to increases in the total use of the system. At current levels of gas and electricity prices, CHP is a marginal activity and existing and potential CHP plant are therefore highly price sensitive. This respondent was concerned to ensure that spurious qualification as a CHP plant does not enable other customers to qualify for CHP tariffs. If, for example, a large industrial site requires gas both for industrial processes and heat-only boilers and for a CHP plant, consumption by the latter must be separately identifiable.

No Special Tariffs for CHP

One party stated that it would seem completely inappropriate for subsidies to be provided to other users of the system for developments of socially acceptable projects, and would create a precedent. The encouragement of CHP development should be done through the electricity market.

One party believes that CHP should not be supported through modified tariffs, but rather via explicit subsidies outside tariff arrangements. Examples of this approach in the UK would be that good quality CHP receives Levy Exemption Certificates (LECs) and qualifying renewables get Renewable Obligation Certificates (ROCs). Similarly another party stated that any incentives to encourage CHP installation and usage is not a matter for consideration in the design of distribution tariffs. In effect, a different capacity/variable split within the tariff structure for CHP sites may be an incentive at the expense of other users of the system. Policies with regard to incentives for CHP, and their financing, is a matter that requires careful consideration and consultation which is not appropriate to the relatively narrow scope of a Transmission or Distribution tariff review.

One party stated that if one is to reduce the capacity/commodity split for the distribution system to 80:20, then there is no firm basis for any argument to suggest that CHP sites should have a different capacity/commodity split (indeed other distribution users might suggest CHP users should have a higher capacity/commodity ratio). If there are serious efforts made to reduce transmission tariffs then users in the distribution system will be encouraged automatically, and thus no specific mechanisms for encouragement of CHP users is necessary or worthwhile without risking distortion to the Irish gas market.

6. Options to Recover the Spare Capacity costs of IC2

6.1. 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.

The consultation paper asked for opinions on the most appropriate option (or combination of options) to deal with the costs of IC2, and whether there were any other options that the CER had not considered in the paper. This section will first summarise respondents' opinions as to the best option, and then summarise the comments given by respondents to each particular option outlined in the paper.

Opinions given by respondents as to the best way to deal with the costs of IC2 are given below:

- A number of respondents said that the best way to deal with the costs of IC2 would be to postalise entry tariffs. It was pointed out that all users benefit from the certainty of volumes afforded by IC2, so all users should pay for it. Some of these respondents said that if postalised entry tariffs are not adopted then options 3 or 5 should be implemented (both of which spread costs related to IC2 to all users). However, one respondent pointed out that any postalisation of IC2 would effectively result in recovery of the costs of IC2 from domestic producers;
- Another respondent called for a move to tariffs based on marginal cost to alleviate the problem of high entry charges paid by importers;
- Many respondents questioned why users of the system were exposed to all of the volume risk for an investment decision that they did not make;
- A number of respondents said that the return on IC2 should be limited, either to the proportion of IC2 actually used, or to the costs of construction;
- Two respondents, however, pointed out that to change the 'rules of the game' now would create regulatory uncertainty, potentially adding to the Transporter's cost of capital and discouraging investment from potential offshore developers;
- Two respondents mentioned the spur to the Isle of Man, with one asking how the Isle of Man is paying for its share of the cost of the pipe between Moffat and the Isle of Man spur, and the other suggesting that revenues from the Isle of Man spur should be incorporated into the regulated revenue base as they are a windfall benefit from the pre-investment in IC2;
- One respondent suggests that the EU Regen grant should be refocused on the interconnectors (other than on the onshore network);
- One respondent says that the depreciation period should be increased from 40 to 50 years;
- One respondent says that only 12 month firm capacity should be sold, allowing holders of capacity to sell it on the secondary market and offset their primary capacity expense;

- One respondent says that the CER should consider the balance sheet position of the Transporter and specifically the desirability of an equity injection by the shareholder;
- One respondent said that option 2 is best; and
- One respondent said that option 8 is best.

Many respondents expressed a concern that Ireland may face a spiral of higher gas prices leading to less gas being used, leading to even higher gas prices, and so on.

The following is a summary of the responses to each particular option outlined in the consultation paper.

Option 1: Current Moffat Shippers Pay for all the IC2 Capacity

There was no support for this option, with all respondents that mentioned it explicitly not supporting it.

Option 2: Current Moffat Shippers Pay Only for IC2 Booked Capacity and Spare Capacity Costs are Deferred

There was a mixed reaction to this option. Four respondents did not support it, with two saying that it would be difficult financially for the Transporter. One pointed out that the Transporter's recovery of costs has already been deferred through the current 10 year levelised tariff. Another respondent points out that implementing the option would impact on future users of the interconnectors.

Two respondents said that they support the option, with another saying, while they accept that the option places a significant exposure on the Transporter, it is worthy of further development. Also, a mechanism is required to ensure that future users of IC2 are protected from facing charges that include all the deferred costs.

Option 3: All Irish Shippers Pay for IC2 Through a Public Service Obligation

Four respondents said that they support this option, with one of them saying that its implementation would ensure a level playing field for Moffat shippers and avoid Moffat shippers being unreasonably penalised by bearing a disproportionate burden of cost for an asset constructed in the wider interests of the entire energy market.

One respondent said that a PSO may be justified as all users will benefit from IC2, though that benefit is limited to the winter period. Another said that, while a PSO recognises the security of supply offered by IC2 (in absence of postalisation), it may be unnecessarily complex.

One respondent said that a PSO would effectively impose the costs of IC2 on indigenous producers, which would be discriminatory in that it would subsidise imported gas to compete with indigenous production.

Three respondents pointed out that security is provided by domestic production, with one going on to say that if there is to be a PSO based upon security of supply, it must go to fund all sources of gas supply to the market.

Two respondents questioned the additional security of supply offered by IC2. However, they recognise that IC2 is volumetrically important, i.e. required to provide capacity for the anticipated increase in imports.

One respondent said that smearing costs cannot be an economically efficient solution, and departs from the principle of cost-reflectivity, while another said that the security of supply benefit should be quantified explicitly and not be presumed to conveniently coincide with the cost of the asset. Another said that this option does not address the demand for a backup service and is asset specific so does not address the problem in the longer term.

Option 4: Storage

All comment on this option was positive, with many respondents saying that the technical and commercial feasibility should be further investigated. Two respondents pointed out that any revenues from such a service would not be a solution in themselves, but could be part of a wider solution.

Option 5: Dividing the Costs of Latent Capacity in IC2/Backup

Five respondents said that they support the implementation of this option, with one going on to say that its implementation would ensure a level playing field for Moffat shippers and ensure that they would not be unreasonably penalised by bearing a disproportionate burden of cost for an asset constructed in the wider interests of the entire energy market.

One respondent said that the implementation of this option would effectively impose the costs of IC2 on indigenous producers, which would be discriminatory in that it would subsidise imported gas to compete with indigenous production.

Two respondents said that the option goes against the principle of cost reflectivity.

One respondent pointed out that backup could come from entry points other than Moffat, with another preferring to see a market-based rather than an administered solution for backup.

Two respondents questioned the additional security of supply offered by IC2. However, they recognise that IC2 is volumetrically important, i.e. required to provide capacity for the anticipated increase in imports.

One respondent said that the option is asset specific and does not address the problem in the longer term.

Option 6: Using a Lower Rate of Return for IC2

Many respondents supported this option, with some saying that the lower return should apply to the portion of the investment not required for the reinforcement of the system in accordance with generally accepted standards of capacity planning.

One respondent says that there is risk attached to an investment, and this investment does not warrant a return to the investor.

One respondent said that implementing the option would not endanger the Transporter financially, while ensuring that the user does not end up carrying the cost burden.

One respondent would support implementation of the option if other options are not workable.

Two respondents point out that the option will place significant exposure on BGÉ, with another saying that the option is not consistent with CER objective of ‘reasonable rate of return for Transporter’. One respondent goes further to say that the investment was sanctioned by the relevant state bodies, so it is unreasonable to not allow a return on BGÉ's cost of capital. Also, unregulated companies are able to made a higher return when investments are successful; returns that are unavailable to a regulated company. So if the Commission disallows a return on capital, the cost of capital will undoubtedly rise to reflect what will be perceived as regulatory opportunism.

Option 7: Profile Costs and Demand over a Period

Some respondents supported this option, pointing out that the investment is planned over a 25 year period, but the tariffs are calculated over a much shorter period, requiring current users to cross subsidise future users. A short period may be appropriate in a mature system, but not in a developing system like Ireland's where a short period leads to unstable tariffs.

Three respondents did not support this option, with one going on to say that the recovery of costs has already been deferred through the 10 year levelised tariff formula, putting BGÉ's financial ratios under stress.

Another respondent accepted that implementation of the option would place a significant exposure on BGÉ, and pointed out the need for a mechanism to ensure that future users of IC2 are protected from facing charges that include all of the deferred costs.

Option 8: Cap Moffat Tariff

Two respondents supported the implementation of this option, with one going on to say that it would ensure a more level playing field for Moffat shippers who would not carry the entire burden of cost of an asset constructed in the wider interests of the entire energy market.

The other respondent suggested a method by which a cap could be calculated:

- Set a cap at a level consistent with the projected demand profiles used to justify the construction of the pipeline. Also, calculate the tariff that would result from following the Ministerial Directives of November 2001;
- The applicable tariff would be the lower of the two so there could be a revenue shortfall;
- The allowed revenues of the onshore system would be increased by the amount of any shortfall. This mechanism would serve to decrease the risk for BGÉ, so the regulated rate of return would be lowered;
- There would be a limit on the amount of the Moffat allowed revenue that can be transferred onto the onshore allowed revenues of 20%; and
- The transfer of the revenue shortfall onto the onshore allowed revenue is against the principle of cost reflectivity, so would be reversed when it is possible to do so in the future.

Another respondent also pointed out that a cap would be against the principle of cost reflectivity.

Six respondents opposed the imposition of a cap, saying that the rationale behind it was unclear and that its imposition would be arbitrary.