Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

The Regulatory Treatment of the BGÉ Interconnectors and Future Gas Transmission Tariff Regime

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Abstract:

This paper outlines the Commission for Energy Regulation's (CER) decision with respect to the regulatory treatment of the BGÉ Interconnectors and the future gas transmission regime.

Target Audience:

Gas Customers, Suppliers, Shippers and Producers

Related Documents:

- CER/12/013 – Proposed Decision – The Regulatory Treatment of the BGÉ Interconnectors.
- CER/11/112 – Consultation (2) – The Regulatory Treatment of the BGÉ Interconnectors.
- CER/11/002 – Consultation – The Regulatory Treatment of the BGÉ Interconnectors in relation to Security of Supply.

Contents

Executive Summary

- This decision deals with the regulatory treatment of the two BGE owned gas interconnectors (“the ICs”) to Great Britain (GB) in the light of new sources of gas coming on stream. It also provides for a general reform of the current transmission tariffing regime.

- The decision follows on from extensive earlier consultation, most notably a Proposed Decision Paper published in February 2012 (CER/12/013).

- The current transmission entry tariffing regime needs reform. Without reform, and assuming the investments in the ICs are not to be stranded, the reduced IC throughput (due to new sources of gas coming on stream) will increase the unit IC entry tariff, potentially significantly so. This higher IC entry tariff would, in turn, push up the wholesale price for gas in Ireland. This would be inefficient and damaging to both consumer interests and Ireland’s energy competitiveness.

- The CER continues to rule out the earlier canvassed options of (i) doing nothing (ii) stranding the IC investments which are considered to be an integral part of the national transmission system and (iii) removing any premium or differential to developers of new gas sources by moving to a completely postalised tariffing regime and ignoring cost conditions at different entry points.

- The CER is committed to a tariff policy which recognises and rewards new entry which can be shown to be efficient by reference to other entry, in particular to entry from GB across the ICs which, it is assumed, will continue to be the marginal source of gas supply for the foreseeable future.

- The CER will base this tariff policy on forward looking long run marginal cost (LRMC) considerations rather than historic cost considerations – e.g. a prescribed portion of the historic costs of the ICs which would be deemed to constitute an efficient price signal to new investors.

- This preference for a forward looking LRMC approach is grounded on (i) sound economic principles (ii) the specific circumstances of the Irish gas system (iii) avoiding arbitrary regulatory judgment calls which would arise with the historic based approach and (iv) compatibility with the applicable EU rules.

- Preliminary indicative LRMC based differentials for entry points to the system are given in the decision, along with the working assumptions underlying their derivation.

- There are risks and challenges posed by moving to an LRMC based tariff regime. It will be particularly important to ensure full transparency and stakeholder involvement in establishing the LRMC methodology. The decision provides for managing these challenges, particularly by establishing a Networks Tariff Liaison Group open to key stakeholders.

- An LRMC based tariff regime will require a mechanism to deal with a potential required revenue shortfall. This is not unusual in any LRMC based tariffing regime. The decision sets out CER current thinking on the optimal revenue shortfall recovery mechanism. The key point, however, is that the chosen mechanism will be designed so as not to mitigate or take from the premium, or differential, available to developers of efficient new sources of gas entry.

- The European Commission (DG Energy) services have advised the CER that its plans to treat the ICs as an integrated part of the transmission system and to base entry tariffs on LRMC at each entry point are, in principle, compatible with EU rules. The CER will keep the situation under review as current proposals for harmonising cross border tariffs within the EU are progressed within the ACER and ENTSOG framework provided for in the Third Energy Package.

- The new tariff regime will come into effect in October 2014 (in line with the expected completion date of the European harmonisation work streams referenced above). The work of the planned Networks Tariffs Liaison Group in assisting the development of the precise methodology for deriving LRMC based tariffs at each entry point will commence shortly. The final decision on approving any tariffs and underlying methodology will, however, rest with the CER.

- In summary, the CER is taking a decision which it considers protects the interests of consumers by preventing them from facing unnecessarily high gas prices in the future, but it also provides an appropriate signal for efficient new entry in a manner that is consistent with EU policy.

1.0 Introduction

1. The paper sets out the CER's decision on the future regulatory treatment of the Bord Gáis Éireann (BGÉ) subsea gas interconnectors in the light of new gas supply sources coming on stream. It also provides for a more general reform of some aspects of the current gas transmission tariffing regime.

2. The decision follows on from a comprehensive public consultation exercise which began in January 2011 see "Related Documents" on the preceding pages. The most recent and relevant document which forms the basis of this decision is the February Proposed Decision Paper (CER/12/013). The CER has also held two public meetings[1] on the issues involved and had a number of bilateral meetings with stakeholders. The CER has also met with and corresponded with the European Commission during the consultation exercise.

3. The legislative basis for the decision is Section 10A of the Gas Act 1976 (as amended by section 14 of the Gas Interim Regulation Act 2002 and Regulation 2 of SI 320 of 2005).

2.0 Overview

4. The issues covered in this decision are complex. They have been described in detail in earlier CER papers, most notably the Proposed Decision Paper of last February. In broad terms, they can be summarised as follows:

   i. New sources of gas, such as Corrib, Shannon LNG or others, will lead to significant reductions in gas flows through the ICs which currently account for over 90% of gas supplies to Ireland.

   ii. To date the largely fixed costs of the ICs (approx. €50m p.a.) have been underwritten by the bulk of customers who account for these 90% plus supplies through a single IC entry tariff.

   iii. A significant reduction in IC flows will lead to a significant increase in the unit IC entry tariff, at least under the current tariff regime where the fixed costs are divided by the throughput to derive the tariff.

   iv. The IC entry tariff plays a crucial role in determining Irish gas wholesale prices for all customers. This is because the Irish wholesale price is

[1] 3rd August 2011 & 1st March 2012.

determined by and large by the clearing price or National Balancing Point (NBP) Price in GB plus the cost of transporting gas to Ireland. This conventional view of Ireland as essentially a price taker, or satellite of the GB market for as long as the ICs remain the marginal source of gas supply, was not seriously challenged in the responses to the Proposed Decision Paper.

v. Developers of new sources of gas will be free to price their supplies up to this new higher Irish wholesale price for gas, or as near to it as the market allows, this would be the economically rational thing for them to do.

vi. So, while Irish gas customers will enjoy new and diverse sources of supply and the associated security of supply benefits, they could also see significantly higher gas tariffs and a significant transfer of resources from them to producers/importers of gas. This is all assuming no change in the current tariff regulatory regime.

vii. This decision addresses these issues by reference to the CER's statutory duties and sets out a resolution which upholds the reasonable interests of the key stakeholders: gas producers and developers, BGN as the owner of the network and the gas customer.

5. We elaborate further below on this overview with some background factual and historical information.

6. The interconnectors (IC1 & IC2) provide two separate physical sub-sea connections to the GB gas market. They provide for over 90% of all of Ireland's gas demand. The ICs were constructed in 1995 and 2001 respectively at the then Government's behest to meet Ireland's security of supply needs as these were perceived at the time.

7. The interconnectors are owned by Bord Gáis Eireann (BGE) and operated by Gaslink. IC1 has a capacity of 17mscm/d[2] with IC2 having a capacity of 23mscm/d[3]. IC2 serves to replicate the maximum of 17mscm/d made available from IC1 and also serves to provide an additional 6mscm/d of capacity to the Irish market (and to the Isle of Man which can take 1mscm/d[4]).

[2] mscm/d : million standard cubic meters per day. Average daily demand in Ireland demand is circa 14 mscm, peak demand in 2010/11 was 22.8 mscm/d.

[3] These capacities depend on a number of factors in particular, the prevailing pressure in GB and Ireland.

[4] Capacity shown for indicative purposes only

8. The annual revenue allowed to the interconnectors is circa €50m with 90% recovered through capacity charges[5] and 10% recovered through commodity charges[6].

9. It is important to understand the context and implications of the 2001 Government decision[7] to commission IC2 in order to set down the associated tariffing arrangements before turning to the issues dealt with in the current CER decision.

10. The decision by the then Minister for Public Enterprise in 2001 to direct BGE to construct IC2 was accompanied by a policy directive on the future tariffing regime for the ICs which should apply for 10 years (i.e. to October 2011). The Ministerial directive introduced what became known as the "Irish Entry/Postalised Exit" tariff regime. In essence this required BGE to charge separate entry tariffs for two separate geographic entry points to the gas system – Moffat and Inch (in Cork) – and to have a further separate postalised country wide tariff for all exits from the system. The Moffat entry tariff would be based on remunerating the *aggregate* values of IC1 and IC2 – i.e. there would be no separate entry tariff for each IC.

11. The Minister's decision on going ahead with IC2 and on the accompanying tariffing regime drew in part on advice from consultants but differed in some significant respects from that advice. The consultants had been asked to advise on a policy for the authorisation of new pipelines and on a tariff regime for third party access to the transmission network.

12. The consultants' recommendation included the following:

    i) IC1 and IC2 should have separate tariffs,

    ii) the Government should authorise the construction of any pipeline that could show long term contractual commitments for a specific amount of capacity,

    iii) to avoid inefficient bypass a 'Public Service Levy' should be applied to all pipelines, whose proceeds would be paid into a 'Geographic Equalisation Fund'.

5 Capacity Charge : charge for reserving space on the pipe to flow gas. Please note that the allowed revenues are being re-examined as part of the PC3 consultation process. (CER/12/058).

6 Commodity Charge : Charge for gas molecules transported through the pipe.

7 CER was not given powers to regulate gas market until 2002.

13. The consultants also considered competition between entry points. They stated that under their proposed model a difference in transportation prices would emerge, and Corrib's gas could command "a *premium*". At that time the consultants considered that the absence of such a premium "*may have been sufficient to prevent Corrib from becoming commercially viable*". In other words, it was recognised at an early stage that the tariffing arrangements for the ICs have the potential to affect the commercial attractiveness of developing new entry points to the Irish gas system.

14. It would appear that at least one of the reasons for departing from the consultants' recommendations was a practical one of timing: There was a perceived urgency regarding the construction of the second interconnector in order to meet Ireland's security of supply requirements. Whatever the precise reasons, these variations from the consultants' recommendations meant that the incentive function which was built into the entry tariff regime was significantly greater than the consultants' recommendations would have suggested. As there were no long term contracts on the ICs *all* the IC users were free to move away to new entry points. Thus, if a new entry point came to the market all the users of the ICs would be contractually free to move to that point and would expect to pay close to NBP plus IC. In other words, users would be paying a "premium" to their new supplier.

15. For some years now the CER has been concerned that the current IC tariff regime would no longer be fit for purpose when new sources of supply come on stream. These expressions of concern were described in detail in the February Proposed Decision. The continuing delays with the Corrib gas coming onshore meant that the current regime could continue, however. Any legal question on the CER's legal right to terminate the 2001 Ministerial directive is now a moot point, given that the directive itself lapsed in October 2011 in any event.

16. In addressing these issues in the February Proposed Decision Paper, the CER set itself the following goals[8]:

i) Set the entry tariff at an economically efficient level.

ii) Set a tariff that is stable in the long term.

iii) Allow for different tariffs at each entry point, thereby allowing a basis differential to remain.

iv) Encourage efficient entry.

v) Be consistent with EU Rules.

[8] See CER presentation at 1st March Public Meeting (see CER/12/030)

The challenge is to strike a reasonable balance between these various objectives.

17. The CER advanced 5 options for consideration:

i) **Option 1 ("Do Nothing")** the CER would do nothing to modify the current tariff structure and allow the IC tariff to rise. Should more and more gas supplies shift from Moffat to non-Moffat sources, the unit IC tariff would keep on rising and exercising upward pressure on wholesale gas prices. While this might be offset to some extent by competition between the different sources of gas, the impact from such competition would probably not be sufficient to balance out the upward pressure and would be unlikely to change the basic "price taker" feature of the Irish wholesale market. So, Option 1 would result in potentially significantly higher gas prices in Ireland.

ii) **Option 2 ("Strand all or Part of the ICs**") the CER would cease to ask the transmission customer to financially underwrite the investments in the two ICs with Moffat, thereby stranding BGE's investments in them.

iii) **Option 3 ("Keep Premium But Cap")** The IC tariff would be capped at some level deemed more efficient than its current level with the remainder of the required revenues being moved to the onshore network. This would be done using some chosen level of use of the ICs. For example, the IC tariff could be capped at its current level, at the average level of a recent number of years, at some deemed "efficient" level or on the basis of only one of the ICs.

iv) **Option 4 ("Remove Premium")** The CER would remove any "premium" or price signalling function from the design of the transmission tariff regime. All transmission network costs would be recovered through a completely postalised regime regardless of the geographic source of the gas purchased by the shipper in the first place. In other words essentially removing separate entry tariffs altogether.

v) **Option 5 (Move to LRMC Entry Tariff Regime)**[9] This option is essentially a variation of Option 3 of capping the premium payable to efficient new entry. In this option the cap would be based on forward looking rather than historic cost considerations. It could be modelled in some part along the lines of the current GB tariff regime. The long run marginal cost (LRMC[10]) of transporting gas at each entry point to the Irish system would be calculated and tariffs would be set for each entry using this LRMC figure. To the extent that the resulting tariff at any entry point was less than the LRMC tariff at Moffat – the presumed marginal source of supply – the difference, or "premium," would accrue to that developer. Thus, it would be designed to promote and reward efficient new sources of gas entry.

vi) The "Irish System" in this context would include *all* transmission assets on the Regulated Asset Base (RAB) which would no longer differentiate between onshore and offshore assets. LMRC tariffs would probably still leave a shortfall on required revenues. To deal with this, it would be assumed that total required transmission revenues should be allocated 50:50 between entry and exit. The likely shortfall from LRMC tariff revenue from this 50% entry share would be recovered from *all* entry points. While the precise details of financing the revenue shortfall were not spelt out, the basic intention was that these should *not* affect the basis differential payable to the developer at an efficient new entry point.

9 This particular option was not formally entitled "Option 5" in the Proposed Decision Paper, but referred to as a "Preferred Solution" by reference to "Options 1- 4" as they were described. For practical purposes, however, it did amount to a fifth option and is therefore referred to as "Option 5" in this Decision.

10 An alternative to LRMC could be short run marginal cost (SRMC). The CER did give some consideration to SRMC. However, it concluded that, while an SRMC approach has certain attractions in economic theory, it is not considered appropriate for a sector such as gas which can be very capital intensive and where there is a premium on reasonably stable and long term signals for new investment.

3.0 Responses to Proposed Decision Paper

18. The CER received 19 submissions in response to the latest consultation paper "Proposed Decision Paper (CER/12/013). The names of the respondents along with a high level summary of their main comments can be viewed in Appendix 1.

19. In general the majority of respondents gave a guarded welcome to, or at least acknowledgement of the case for moving to an LRMC based tariff regime. One respondent did argue against LRMC, however, particularly where there is no congestion on the system. There was no explicit call for stranding of the ICs.

20. Some respondents also made it very clear, however, that they would only give a final view on an LRMC methodology once they had seen more details surrounding such elements as the LRMC methodology, 50:50 split, common charging etc. Many respondents pointed out that the proposal was light in detail and not very clear. Transparency in any LRMC based regime would be very important, a number of stakeholders emphasised.

21. Other comments/concerns included:

    i) the introduction of LRMC without prior consultation;

    ii) the absence of timescale and details with regard to the methodology for setting the LRMCs, auctions, under/over recoveries.

22. The CER acknowledges the above points, and addresses them in the decision section below.

4.0 CER Decision

4.1 Narrowing down the tariff options

23. Of the various policy options described in the February Proposed Decision Paper, the CER made it clear that it was very unlikely to pursue three in particular, and set out its reasoning behind this thinking. These options were:

Option1

- Do nothing, and continue with existing tariff regime notwithstanding the significant upward pressure on gas tariffs which would in all likelihood arise from new supply sources coming on stream.

Option 2

- Strand all or part of the interconnectors when new sources come on stream.

Option 4

- Remove any tariff recognition, or premium, to new sources of gas by, effectively, removing any entry tariff and moving to a completely postalised tariff regime.

24. No substantive or convincing case has been put to the CER in the responses to the Proposed Decision as to why the CER should reconsider its position on these options. Neither has the CER itself, on reflection, reason to reconsider its earlier thinking on these options.

25. On Option 1, for example, the CER does not consider that it is bound to continue indefinitely with the current tariff regime by the principle of legitimate expectations or by its own documented behaviour over the last decade. As stated previously, option 1 is likely to lead to significant increase in gas tariffs for customers that would be damaging to them and to our general energy competitiveness. The February Proposed Decision[11] paper set out the CER's arguments on this issue in detail and the responses from the stakeholders have not caused the CER to reconsider its position.

26. On Option 2, the CER continues to believe that its position not to strand the ICs is reasonable and does not amount to unfair discrimination within the meaning of domestic or EU applicable law. The decision to construct the ICs was taken by the Government of the time and it would not be appropriate for the CER to revisit this. The February Proposed Decision paper sets out the CER's arguments on this

[11] See section 5.1 CER/12/013

issue in detail. Also, correspondence from the European Commission[12] would also appear to support that position. Furthermore, earlier fears of the CER, that such stranding could have cost implications in terms of the potential impact on the WACC allowed on BGN's asset base for tariff setting purposes, have been supported by consultancy advice it has since received to this effect (see report from Oxera to CER on this issue in **Appendix 2**).

27. On Option 4, the CER remains of the view that full postalisation of all entry tariffs (i.e. removing any premium/reward for lower cost entry) would be a short-sighted policy which would not provide incentives for efficient new entry, and, in any event, could be difficult to reconcile with EU rules in this regard which require some meaningful differentiation between entry and exit tariffs.

28. We are left with the Options 3 and 5 - designing the entry tariff regime in such a way as to retain a basis differential to reward new[13] sources of gas from an entry point which can be shown to be more economically efficient than Moffat and deciding how best to cap such a premium[14].

29. For the avoidance of any possible doubt, the CER repeats that it *does* wish to retain a basis differential/premium to incentivise efficient new entry. It is important to emphasise that this differential is to incentivise *efficient* entry. Thus it could be the case that a low or zero differential might be appropriate in the event that further new entry might be considered unnecessary or inefficient.

4.2 Capping the Premium for New Entry: Historic or Forward Looking Approach?

30. An incentive can be calculated on an historic basis (Option 3) or on a forward looking basis (Option 5). As several respondents noted, both these options are ultimately the same in their broad objective of setting some parameter for capping the tariff incentive signalled to new entry.

31. The CER's thinking in the Proposed Decision was clearly to favour an LRMC (forward looking) rather an historic approach.

32. An LRMC approach to network tariff setting is well grounded in economic theory. The basic idea is to set tariffs to reflect the costs of providing an incremental unit

[12] See CER/12/030c

[13] This paper uses the phrase "new" sources or "new" entry; this is because the paper focuses on a forward looking price signal. However, a basis differential may arise at existing points also e.g. Inch.

[14] In this context any such premium paid could be considered remuneration for the security of supply benefit provided by the entry point earning the premium.

of output at the different entry points to the system. Users will continue to purchase output at an entry point for as long as this is more valuable to them than the cost of investing in incremental output at that point, thereby maximising economic welfare.

33. In Ireland's case, where an entry point has a lower LRMC than the marginal entry point (i.e. Moffat), then an LRMC based tariff regime would either encourage shippers to source their gas at that entry point and/or reward producers to develop that entry point by allowing them price their gas up to, or very near to, the higher LRMC tariff prevailing at Moffat. In this way efficient new sources of gas entry are encouraged. By the same token, the higher LRMC cost of investing in incremental output at Moffat is avoided, or at least delayed, which is to the benefit of the general gas customer.

34. The Proposed Decision Paper drew attention to the advantages of an LRMC approach to transmission tariff setting. It is logical, it is based on estimated cost considerations at each physical entry point, it is forward looking and therefore more likely to encourage efficient behaviour than an historic based approach. It is also clearly compatible with – though not actually required by – the EU Third Package regime. Many respondents acknowledged these points in their submissions. Moreover, given the historic circumstances and shortcomings of the inherited current tariff regime as described above (single entry tariff covering both ICs, absence of any market test for the construction of IC2 etc), the case for moving to an LRMC approach becomes stronger, in the CER's view.

35. However, it is acknowledged that LRMC based tariffs can be complex to calculate. There can be much debate on selecting an optimal methodology. It also has the potential to add to tariff unpredictability if the methodology chosen is not well bedded down at the outset or if it is not based on a reasonably lengthy time period. Such volatility is not good for improving the regulatory climate for actual or potential investors.

36. We should not exaggerate the difficulties associated with moving to an LRMC regime, however. On the complexity aspect, there would certainly be a need for ensuring transparency and industry acceptance of the chosen methodology for calculating the LRMC tariffs and the CER will be addressing this. The revenue shortfall issue, is a familiar challenge to regulators in other utility sectors and is capable of resolution.

37. A more general point has been made that a move to an LRMC regime could give rise to concerns over regulatory uncertainty and a concern of decision making becoming more unpredictable than in the past. Will the regulator wish to revisit

the LRMC methodology at frequent intervals, for example, and thereby create a more uncertain environment for investors and stakeholders?

38. This concern is understandable. We should not forget, however, that the CER is required - by good regulatory practice at least – to behave in a manner which avoids, or at least minimises, regulatory uncertainty. This duty applies regardless of whether a historic or forward looking LRMC tariff regime is followed. The temptation for the regulator to revisit the tariffing methodology could equally arise if the new methodology is based on some "deemed efficient" share of the historic IC costs at the outset. This share could well be open to frequent debate depending on the impact it was having on individual stakeholders.

39. In summary, the CER acknowledges that it has a duty to behave consistently and promote regulatory stability for investors, subject of course to the obvious constraint that it cannot bind its successors.

40. Current thinking and practice in the EU on entry tariff design is summarised in the box below.

Current EU Thinking on Historic/LRMC Approaches

i) The Third Energy Package of 2009 calls for the harmonisation of cross border gas transmission tariffs. This work has been underway for some time now and is expected to be completed by 2014. The work on the Irish gas transmission tariff regime will take place in parallel with European cross border harmonisation.

ii) It is interesting to note here that the debate on the "historic versus LRMC" approach to setting entry tariffs has also surfaced within the EU in recent times. This is driven in large part by the Third Energy Package and the development of EU wide network codes by ENTSOG on foot of Framework Guidelines being developed by ACER. These cover a number of issues – e.g. capacity allocation, balancing, congestion management and, in more recent times, tariff structures. While ACER's work on the development of a Framework Guideline on Harmonised Transmission Tariff Structures is still at a relatively early stage, certain interesting findings are emerging.

iii) In a Consultation Document of February ACER noted that at present two alternative cost concepts are used for the purpose of setting the “reference price” for each interconnection point. In turn this price will be used to determine the reserve price at these points which will be a feature of the mandatory auctions to take place under the future network codes. These concepts are:

- Long Run marginal Cost
- Actual Costs Incurred

Effectively these concepts correspond to the forward looking / historic approaches to tariff setting as set out in the CER’s Proposed Decision of last February.

iv) The important point to note is that ACER has not, at least to date, suggested that one concept is necessarily better than the other, or that one should be prescribed at EU level rather than the other. Current indications are that choices on this aspect of tariff setting may be better left to individual Member States given the very different characteristics between gas transmission systems.

41. Coming back to the immediate issue facing the CER and the gas industry in the present decision; the main arguments advanced by the respondent who advocated a historic cost based approach rather than a forward looking LRMC based approach to capping the premium on new entry sources fall under two broad headings:

    i) A greater familiarity and perceived predictability with a historic based approach and

    ii) The absence of network congestion and any resulting need to allocate scarce capacity on the Irish network. The presence of congestion is the conventional rationale for adopting an LRMC based tariff regime.

42. On (i) we have partly addressed this issue of general regulatory predictability above. That said, we acknowledge that, on the face of it, an argument can be made that historic cost is a concept that is familiar to the Irish gas industry. The process of determining the allowed costs which will form the basis of entry tariffs

is likely to be more transparent and straightforward (in that the costs should be easy to identify) than with forward looking regime. It might also be expected that the element of the ongoing costs relating to historic investment (e.g. maintenance) should be relatively stable over time.

43. However, the issue still arises as to whether or not the tariff resulting from historic costs would be stable over time. In order to calculate a capped tariff it would be necessary to arrive at some deemed "appropriate" level of utilisation to calculate the tariff. Would this be based, for example, on the utilisation expected at the time the asset was built, or on utilisation over the last number of years (if so how many years) or would it be based on expected utilisation in future years? Any such decision would be open to calls for regular review. It could well be considered quite arbitrary in nature.

44. On the argument at (ii) – the "absence of congestion" argument – the respondent cited in support an extract from a 2002 report compiled for the European Commission as follows: *"Cost-reflectivity has fundamentally different implications depending on system growth and actual or prospective congestion. With growth or congestion, capacity is scarce and tariffs face the principle challenge of ensuring efficient allocation. With no growth or congestion, the primary concern is allocating the costs of previous network investments among system users....... In the absence of congestion however there are no efficiency implications to the choice among alternative pipeline routes. Tariffs should have a retrospective focus, allocating the costs of existing investments in ways that correspond to intuitive notions of fairness. Allocation methods should consider the extent and nature of system use by customers."*

45. The respondent went on to argue that LRMC is considered appropriate only where there is congestion and then LRMC will lead to efficient outcomes only where there are long term contracts at the time of investments. This respondent noted issues that arose in GB where upon an investment being made the LRMC fell but absent long term contracts "*there is no-one to pay for the actual costs incurred*". In later correspondence this respondent noted that in their view "*More generally, efficiency tends to arise when the users of infrastructure know that they will have to pay for its use over the useful life of the investment*"

46. In the CER's view, the essential advantage of an LRMC approach over a historic approach to entry tariff setting is that it would be applying sound economic principles *to the specific circumstances of the Irish gas system*. This last consideration is critical.

47. Unlike the GB and many other gas systems, no Irish users have long term contracts on the ICs. Whether the original recommendation at the time of IC2 construction that such long term contracts should be a precondition to going

ahead with the project was correct and/or feasible at the time is neither here nor there now.

48. Moreover, it is hard to see much prospect or commercial rationale for shippers entering into a long term contract now or in the future *at the Moffat entry point*. This does not necessarily apply for other entry points, we emphasise. A gas shipper will have little incentive to commit long term capacity at Moffat (i) if there is little perceived prospect of congestion at that point (ii) given that Moffat connects the shipper to a highly liquid trading hub in GB and (iii) given that Moffat is likely to continue to be the marginal, and most expensive, entry point to the Irish gas system. This absence of long term contracts at Moffat means that *all* shippers are contractually free to switch their supply source from Moffat to another entry point, if it is commercially attractive to do so.

49. In effect, therefore, Moffat is likely to continue to represent the “price to beat” for developers at other entry points for the foreseeable future, just as it has done in the past for the Inch entry point. This is a key distinguishing feature of the Irish gas transmission system which has to be borne in mind in considering the optimal future tariff regime.

50. For this very reason – the “price to beat” character of the Moffat entry point – it is essential that the methodology chosen for calculating the regulated entry tariff at Moffat is based on sound economic principles, even in the absence of congestion. An LRMC approach to calculating this tariff is more likely to produce an economically efficient and welfare maximising result than a more arbitrary approach based on some share of the historic costs of the ICs deemed to be a proxy for an efficient new entry signal.

Illustration “Price to beat” concept

Consider a scenario where the ICs tariff has been set at €10/unit using historic cost, but the LRMC of additional capacity at the interconnectors is €6/unit.

Assume a merchant interconnector which is profitable at €8/unit could be built. This will attract customers as long as it keeps its charges below €10/unit even though it only needs to charge €8/unit to be profitable.

Considering price alone, this would be inefficient, as it would have been more efficient to add capacity (when required) at the cost of €6/unit.

If the IC tariff was set using LRMC new capacity would likely be built only if it could beat €6/unit.

51. One further point made by the respondent is worth considering. If a developer was to construct entry capacity, the very act of constructing new capacity at one entry point might itself cause the LRMC at Moffat to reduce or even to drop to zero. This, it is argued, adds to the risk of tariff volatility and could frustrate the stated objective of the LRMC based tariff regime.

52. In response we would say that, while tariff predictability is an important factor in any regulated regime it should not be pursued blindly or at the expense of efficiency and consumer welfare. Moreover, providing the methodology for calculating the LRMC is clear, participants (both potential producers and consumers who may wish to contract with new supply) can consider the expected impact of the addition of capacity in advance of making any investment or commitments.

53. To conclude on this particular aspect of the decision, the CER is of the view that given the specific features of the Irish gas system, given the continuous presence of the price to beat signal, the use of LRMC to set entry tariffs will lead to more efficient outcomes for the gas industry, as additional supply is only likely to come on to the system if it is efficient.

4.3 How to Meet an LRMC Tariff Revenue Shortfall

54. A familiar issue with an LRMC tariff regime is that, because LRMC tariffs are essentially looking at *future* cost considerations, there is no guarantee that the revenue accruing from them will be sufficient to meet the revenues required to finance the historic assets in place. Therefore they need to be topped up, as it were, with a supplemental revenue stream. In this case, this would take the form of a common charging element to the tariff design.

55. The CER's current preferred option regarding the common charge would be to create a single capacity charge, common to all entry points. This charge would be levied at all entry points in addition to the location specific entry point charges[15]. In this way the absolute difference in level between entry point charges would be maintained (unless the auction for a given entry point cleared at a price higher than the reserve price). The CER is also drawn to the case for allocating the recovery of total transmission revenues 50:50 between entry and exit tariffs and, within the entry tariff regime, to retaining the current 90:10 split between capacity and commodity based tariffs. Such an approach should preserve the locational

[15] Thus the resulting charge at each entry point (LRMC plus common charge) could be considered analogous to the "P0" charges in the GB system, this is the cost of delivering the obligated capacity for each GB entry point to the system.

price signal between entry points while also maintaining a desirable overall capacity/commodity split.

56. Several respondents to the February paper raised concerns with this aspect of the proposal. These concerns centred on a perceived effect of a 50:50 split on the basis differential. This may not have been fully clear in the CER's February paper. The CER wishes to reiterate, for the avoidance of any possible doubt, that it does wish to retain a basis differential to incentivise efficient new entry.

57. The CER remains of the view that an overall 50:50 split of network cost allocation charges between entry and exit points is appropriate in that in the normal course of events, each molecule that enters can be expected to exit, therefore a 50:50 split of revenues can be viewed as cost reflective. There is clearly a need for infrastructure to get gas from the entry point to the market, a pre determined split of 50:50 reflects the cost of such infrastructure. Absent the recognition of such costs, entry tariffs of zero could arise. It is considered good practice to seek to avoid setting tariffs at zero. The CER is, however, open to arguments on different splits and these will be teased out in the planned Networks Tariff Liaison Group (see section 4.5 below).

4.4 Indicative Tariff Differentials

58. To try to give some order of magnitude of a basis differential that may arise for developers under an LRMC based tariff regime, the CER has asked BGN to develop a set of indicative tariff differentials for four entry points to the system: Moffat, Inch and Corrib and the potential entry point at Foynes. These resulting indicative basis differentials are set out below along with the underlying assumptions.

59. In calculating the differentials, the following working assumptions were made at the request of the CER:

- The figures were developed with reference to the current BGN 10 year network development plan and the Joint Capacity Statement.
- In order to give a 20 year timeline, current forecasts from both the joint capacity statements and BGN network developments plans were extrapolated using a modest forecast of growth.
- No assumptions were be made for new entrants (other than those mentioned above) in this scenario.

- For the purpose of these calculations, each entry point was calculated on its own merits, i.e. Moffat plus one other, the calculation did not take into account flows, pressures, reinforcement etc needed on account of other entry points and to this end system analysis will need to be undertaken in the calculation of the ultimate LRMCs.

60. For each entry point the following items were considered when calculating the Long Run Average Incremental Cost (LRAIC):

- Aggregate demand for next 20 years;
- Existing deliverability;
- Additional investments required to meet incremental deliveries;
- Allowance for compression costs based on year ahead snapshot gas cost.

Indicative Tariffs Differentials:

Table of Indicative Tariff Differentials with Moffat

Inch:	circa 76-158 € / pkdayMWh
Corrib:	circa 95-158 € / pkdayMWh
Foynes:	circa 135-158 € / pkdayMWh

61. With reference to the highest differential in the table above, the assumption is that no new infrastructure is required or if it is then the developer underwrites the new infrastructure at the relevant Entry point[16].

62. The lower differentials indicate that additional infrastructure may be required over 20 years. Multiple entry points may interact with each other potentially requiring investment related to these entry points. Also the presence of multiple entry

[16] Some might question whether or not a calculation that sees no increase in capacity or no increase in costs at an entry point can be classified as LRMC. However, it may still be an appropriate forward looking locational signal to give to the market. This issue will be considered as part of the planned Network Tariffs Liaison Group.

points may push out the requirement for reinforcement at Moffat. Considering these interactions will be a key element of the design of the methodology which will be facilitated and discussed by the planned Network Tariffs Liaison Group.

63. The LRMC methodology will ultimately need to be determined in consultation with stakeholders and approved by the CER, and the resulting LRMCs calculated under the agreed methodology may produce different results.

64. The common charge element of the expected final tariff is excluded for clarity but will be part of the final tariff at each entry point. The level of the common charge will only be known once the expected bookings at each entry point are known. For the purpose of this paper the CER takes the view that it is the differentials that are of most interest to stakeholders.

65. The differentials provided above are indicative and they should not be regarded as final in any way. They were calculated using high level assumptions and did not take into account interaction in flows between different entry points.

4.5 Tariff Design and Stakeholder Involvement

66. As indicated earlier, the CER appreciates the need for a platform for meaningful stakeholder involvement in working out the final details of the planned LRMC based entry tariff regime. To this end, a Network Tariffs Liaison Group will be established, to be convened by the CER and consisting of the system operator and representatives of the upstream and downstream gas sectors. The Liaison Group will meet on a regular basis throughout the tariff determination process. It will provide a forum to communicate and discuss ongoing network tariffs issues of interest to the industry, for example the form of LRMC/locational signals, the balance between cost allocation and forward looking signals, the treatment of future investment in this context, dealing with under/over recoveries etc. For clarity, it will not be a policy-making body. Policy issues that arise at the meetings will be considered and decided upon separately by the CER as appropriate.

67. In addition to the CER, the current system operator (Gaslink) and the asset owner (BGN), representatives from the following parties, representing the broad spectrum of stakeholders impacted by network tariffs, are invited to attend the Liaison Group meetings:

i) the Irish Offshore Operators Association (IOOA);
ii) Corrib Partners;
iii) Manx Electricity Authority;
iv) PSE Kinsale Energy;

v) Shannon LNG (SLNG); and,
vi) shippers from Code Mod Forum

68. The CER will shortly be writing to these stakeholders inviting them to participate in the Group. It is expected that the first meeting of the Group will be in September 2012.

4.6 EU Compliance Considerations

69. The CER is aware that questions of the compatibility with EU law of some of the options advanced in the Proposed Decision Paper – particularly Option 5 – have been raised with the European Commission by at least one stakeholder. The CER has continued to reflect further on its duties to comply at all times with EU law. However, we remain of the view that the present decision is compatible with all the applicable EU laws.

70. Specifically, the CER take comfort from the letter of 7 February 2012 from the European Commission (DG Energy) to CER (and since published on the CER website CER/12/030), to the effect that the proposed LRMC approach (Option 5) would, in principle, be compatible with **Regulation 715/2009**. Obviously the precise detailed methodologies for setting the tariffs will also have to be fair and non-discriminatory.

71. On **State aids**, the CER has engaged with the European Commission (DG Competition), via the Department of Communication, Energy and Natural Resources, in response to a complaint from one stakeholder to the effect that Option 5 would amount to an illegal State aid. CER is satisfied that its present decision does not constitute State aid and has advised DG Competition to that effect with reasons set out. We await the outcome of the State aid procedure. Should DG Competition conclude differently, then of course CER would have to reconsider its position. CER has no evidence of that to date.

72. Lastly, the CER is satisfied that its current decision is compatible with the results emerging to date from the ACER and ENTSOG work streams on developing an EU wide code on network tariffs. The situation will of course be kept under review.

4.7 Other Issues Raised

73. The following section discusses briefly some other issues/questions raised by respondents to the proposed decision paper in February.

Legislative Authority

74. One respondent argued that the CER may not have the statutory power to make the Proposed Decision. It argued that, by virtue of Section 10(A) (17) (b) (i) of the Gas (interim) (Regulation) Act 2002, the CER's powers to issue directions to the system operator only arise "in respect of the basis for charges for third party access to .... a *facility* (emphasis added) under the control of the operator" which, in turn, is defined as "transportation of gas through a pipeline operator's pipeline". In the present case, the respondent argues, Shannon LNG would not be seeking access to the ICs and therefore there is no basis in law for CER requiring that party to pay charges in respect of the IC pipeline.

75. The CER does not accept this argument.

76. The statutory provisions on third party access set out in the 2002 Act and in subsequent amending regulations empowering the CER to issue direction to the system operator are expressly designed to transpose the Directive of 2003/55/EC into Irish law. Therefore they must be interpreted in a manner which gives effect to the Directive, and to its successor, Directive 2009/73/EC. It is clear from reading both Directives that directions issued from time to time by the CER to the system operator on "the basis for charges for third party access" relate to access to the "transmission system" as defined in the Directives, as opposed to access to individual elements or pipelines within that system. The Directives refer exclusively to "access to the transmission system" and the term "system" is so defined as to make it clear that it refers to the "transmission networks". It is also clear that the ICs constitute an integral part of the Irish transmission system (a view supported by the European Commission services).

77. For these reasons, the CER is satisfied that it does have the legislative authority to issue a direction to the system operator to implement the planned reform of the transmission tariffing regime.

Isle of Man

78. One respondent noted that while the draft decision paper stated that the position of the Isle of Man would not be unduly affected, the meaning of this statement was not made clear. It is worth noting that the Manx authorities have raised no issue with the proposed decision and in fact "offer our broad support in principle for the proposed solution". The position of the Isle of Man will be considered as part of the Network Tariffs Liaison Group. The statement in the proposed decision paper was merely intended to reflect the reality that the Isle of Man is connected to only one interconnector and that this fact would have to be considered in developing the enduring solution.

Northern Ireland

79. One respondent stated that "the position of Northern Ireland is totally unexplained". It is fair to say that there was no mention of Northern Ireland in the proposed decision paper. In the intervening period the CER has published a paper concerning tariffing arrangements on the South/North Pipeline (CER/12/066). This paper confirms that the tariffing arrangements on the South/North Pipeline will be reviewed as part of this process. It is worth noting that the CER for its part can only operate within its own jurisdiction. The CER is determined, however, to seek to treat all those who benefit from the ICs in an equitable manner.

Interconnector License/Ofgem etc

80. A number of respondents raised concerns as to how any new arrangements would impact the current licensing arrangements in GB. In this regard we note that CER is already regulating assets located in GB and the GB authorities have been satisfied to date to "switch off" certain licensing provisions with regard to these assets. The CER has no reason to believe this situation will change as a result of this decision.

New Path

81. One respondent was concerned that their responses to the earlier paper (CER/11/112) had been disregarded and a new path bereft of consultation was presented in the proposed decision paper as fait accompli. The CER restates that no decision was made in the Proposed Decision Paper. The CER considers that Option 5 is essentially a variant of Option 3 using forward looking pricing rather than historic.

Creating a "bank" for unrecovered costs

82. One respondent acknowledged the argument for not stranding the IC costs but repeated their suggestion that a "bank" be created for unrecovered costs. The CER takes the view that the creation of such a bank could lead to significant risk that costs may never be recovered and that this proposed solution could lead to the de facto stranding of the ICs. In simple terms the utilisation of the ICs might not increase over time to a level sufficient to remunerate the investments.

Change of mind

83. One respondent noted that in a 2008 Common Arrangements for Gas (CAG) Conclusions paper, the CER together with co-author the Northern Ireland Authority for Utility Regulation (NIAUR) stated that where there was excess capacity "backward looking approaches to tarrifing are likely to be more appropriate than forward looking approaches". After considerable reflection and consultation with industry the CER has taken the view that given the specific features of the Irish gas market, forward looking approaches are indeed appropriate. The CER acknowledges that this is different to the conclusion reached jointly with NIAUR in 2008.

Contradiction

84. One respondent highlighted what they saw as a contradiction in CER's thinking in that this consultation process centred on a potential underutilisation of the ICs while CER/11/206 of November 2011 focussed on a potential constraint at Moffat in 2013/14.

85. The CER does not see any contradiction. The November 2011 paper focused on a potential short term constraint that could arise in winter 2013/14 if a number of contingencies were to arise *prior to* the coming on-stream of new gas entry points. The CER was at pains to emphasise that the paper was addressing a short term and unlikely risk and "does not address long term security of supply issues". The present decision, by contrast, focuses on reduced utilisation of the ICs *after* new entry points come on stream and addresses longer term security of supply issues.

5.0 Conclusion and Next Steps

86. The CER concludes that the current gas transmission entry tariff regime will be reformed on the following lines;

    i) The current distinction between offshore and onshore assets for tariff setting purposes will cease. The ICs will be treated as an integral part of the transmission system no different to other assets.

    ii) The entry points to the system will be located where assets transporting gas from outside the system actually join up with assets comprising the integrated system or Regulated Asset Base (RAB). So, the entry point for gas from GB will be at Moffat.

    iii) Tariffs at each entry point will be set separately on an LRMC basis.

    iv) A premium, or differential, in entry tariff levels will be retained to reward efficient new entry and will not be mitigated by the mechanism to be introduced to compensate for a revenue shortfall from LRMC entry tariffs.

    v) The investments in the ICs will not be stranded.

87. The CER intends issuing a direction to the TSO (Gaslink) to effect these reforms pursuant to Section 14 of the Gas (Interim) (Regulation) Act, 2002 with effect from 1 October 2014. Before doing so, however, the CER will be establishing and chairing a Network Tariffs Liaison Group to deliberate on the methodology for deriving the definitive LRMC tariffs for each entry point to the system. The Group's deliberations will form an important input to the approval of the final methodology for calculating entry tariffs which will be a matter for the CER.

88. The CER will shortly be writing to stakeholders inviting them to participate in the Liaison Group.

Appendix 1: Summary of Responses to Proposed Decision Paper

The CER received 19 submissions in response to the February 2012 Proposed Decision paper CER12/013. The responses themselves are summarised below. Responses were received from the following organisations/individuals:

- Ballylongford Enterprise Association
- Bord Gáis Energy
- Bord Gáis Networks
- Diarmuid Lynch
- Energia
- Endesa Ireland
- ESB
- Irish Offshore Operators Association
- Manx Electricity Authority
- National Electricity Association of Ireland
- PSE Kinsale Energy
- Safety Before LNG
- Shannon Foynes Port Company
- Shannon LNG
- Shell E&P Ireland
- Statoil
- Tarbert Development Association
- Vayu
- Vermillion Energy

Non confidential responses are published in conjunction with this proposed decision paper.
The respondents commented on various aspects of the CER proposals in CER/12/013. This section summarises some of their high level comments.

Ballylongford Enterprise Association (BEA) asserts the opinion that the CER's aim is to protect the state sector from competition. BEA notes that the CER have been considering this particular issue since 04/01/2011 and after 13 and half months, were only able to come up with a draft proposal. BEA further notes that in fact, the CER has been dealing with Shannon LNG since 2006 and in 2011 moved the 'goal posts' to favour Bord Gáis.
BEA questions whether this process is too complex for the CER.

Bord Gáis Energy (BG Energy) considers that implementation of the LRMC is a reasonable approach for a large utility network. However there are many different methodologies for the implementation of a LRMC approach depending on the incentives and signals required for the specific system. BG Energy state "it is difficult to give definitive support to the CER's proposal at this stage in the absence of any impact assessment regarding the potential impact of LRAIC on future entry point other that Moffat".

BG Energy believe it is impossible for respondents to fully support a principle of LRAIC without fully understanding all pricing options and their implications for costs to customers. BG Energy will await the outcome of the CER's upcoming modelling exercise to determine appropriate pricing for each entry point before providing express judgement for one methodology over another. BG Energy considers in the interests of completeness, the CER should provide an impact assessment of all pricing methodologies not only LRAIC in its analysis.

Bord Gáis Networks (BGN) wish to highlight that fact that no party spoke in support of stranding at March 1st public meeting, and those that did speak were supportive of both the IC system and of its contribution to the gas market. BGN believes the CER must now firmly state that there will be no stranding of any part of the Interconnector system, and then ensure that any proposed new tariff structure is robust, establishes a stable regime for the future and ensure that the asset owner is allowed recover their revenue entitlements.

BGN divided their response into two sections. Part 1 dealt with the issue of the "Treatment of the IC System" and Part 2 addressed the "Entry Tariff Structure".

In Part 1 BGN describe the benefits of the IC system under headings; Security of Supply, Economic importance of the IC's, Environmental, Meeting Market Demand and Utilisation, Providing Operation Flexibility. BGN note that any adverse amendment to a regulatory decision including stranding of regulated assets, would adversely impact not only on the gas sector but also on the electricity and other regulated sectors. BGN go on to say that the IC system is being well utilised in excess of what was anticipated at the time of construction and has received all the required approvals and is delivering significant benefits to consumers through the gas and electricity markets.

In Part 2 of their response BGN note the CER's primary duty to protect the interest of consumers and in doing so should examine the form of the entry tariff itself in order to protect the consumer. BGN accept the mechanism for recovery of IC revenue should be modified in order to ensure stable entry tariffs, and to ensure an efficient gas market is developed into the future. Setting the IC tariffs at a level reflecting LRMC would ensure that tariff structures reflect the underlying marginal cost of gas transmission, allowing producers and consumers to allocate resources efficiently in response to tariff price signals.

BGN believe the LRMC approach could support diversity of supply as by setting a stable tariff for the IC's, the impact of tariffs on the price of gas on the island would be relatively predictable. This will encourage investment in a stable environment. Finally BGN encourage the Commission to progress and finalise the new entry tariff structure such that this uncertainty is removed from the market and confidence is restored for existing investors.

Diarmuid Lynch (DL) fully supports the proposed CER treatment of Moffat Entry and Interconnectors. Any mechanism which either stranded Interconnectors or created a barrier to entry of UK gas (i.e. higher entry tariffs) would NOT serve the best interests of the Irish gas user. DL supports some version of LRMC to be used in setting the economic cost of each entry, saying this is “sustainable and gives predictability”. DL urges caution with respect to auctions and their design. DL suggests some “ticket to ride” is part of any design of the auction mechanism whereby one must be a shipper with a legitimate interest at that exit point.
Finally DL states “it is important that this decision sets the long term sustainable framework for gas transportation in Ireland”.

Energia states “its views should be viewed as preliminary and in no way determinative of our final position, which will be provided as the different aspects of the final proposal are developed by the CER and consulted upon with industry”.
In general Energia endorses the principles set out in the paper with respect to the solution, commenting that the high level proposals to move the ICs to form part of a wider “transmission system” and the change in entry point to Moffat appear to represent a reasonable approach, similarly the use of auctions appears to be consistent with forthcoming European Network.

With respect to the next steps Energia considers it imperative that the CER, upon timely publication of a decision, provide a timetable to market participants for consultation on substantive matters of the preferred approach.

Endesa Ireland (EI) notes the draft decision does not make detailed proposals:

- As to whether reserve tariffs should be based on LRMC or SRMC and the methodology for calculating either,
- On how common charging would be implemented where entry exit revenues are not recovered on a 50:50 basis, and
- On the resultant differentials between LRMCs at entry points.

EI tentatively supports the CER proposal, however the issues listed above must be resolved. EI calls on the regulator to ‘flesh out’ the proposal made in the draft decision and requests an opportunity to comment on the full proposal be given to market participants prior to any decision being taken.
EI also queries if Moffat is to be an entry point to the Irish system, whether there is an interface between the Irish and Northern Irish gas systems, as well as the Isle of Man system.

ESB agrees with the CER proposal not to strand any of the BGE Interconnector assets. ESB state “any regulatory decision to strand part of the existing gas interconnector infrastructure would have widespread consequences across the wider regulated utility sector. ESB make the comment that the second gas interconnector does, to a significant degree contribute to security of gas supplies and as such its cost must be recoverable. Stranding of the second BGE interconnector costs would send a very negative signal to the capital markets for all future regulated utilities' infrastructure projects.

ESB agrees with the CER proposed decision that the Interconnectors will be deemed to be as much part of the transmission system as other transmission assets. ESB also supports CER thinking the LRMC of transporting gas could be used as the basis for calculating the regulated entry tariff. ESB believes this approach will reduce the risk of a perverse wholesale price outcome following new entry points becoming effective on the system.

ESB made the following comments on the proposal to use LRAIC methodology to calculate the LRMC:

- welcome further detail be provided and that the proposed methodology be fully consulted upon before implementation;
- agree that LRAIC looks a more stable basis for determining LRMC when compared with LRIC
- have concerns regarding any charging methodology that gives locational signals. In addition to the objectives of efficiency and cost recovery it is imperative that any such signals be stable, equitable, transparent and predictable;
- In the event that the marginal signal over/under recovers it is imperative that the means of ensuring the correct recovery of revenues does not exaggerate the locational signal. ESB considers that it may be better to under-state than over-state a locational signal, given the impact it could have on market participants.

Irish Offshore Operators Association (IOOA) considers the CER's proposed decision represents a fundamental shift from past regulatory approach in Ireland.

THE IOOA suggests the CER enter into a comprehensive consultation before proceeding to any decision and that the following points are addressed in the next consultation:

- Detailed timeline to October 2014, outlining when future consultation documents are expected to be published and what information will be provided;

- The next consultation should assess what is and isn't working in our neighbouring market especially with respect to under recovery and unintended incentives for shippers to either avoid long term capacity bookings or participating in an auction process at all. The IOOA note the IUK & BBL are not part of the BG onshore system;

- To address whether there is a risk of DECC and/or OFGEM claiming regulatory remit (or other legal challenge) on assets located in their geographic territory;

- To explain the impact of any existing GB interconnector licensing arrangements;

- To publish the exact methodology including detailed spreadsheets that BGN used to calculate the LRAIC of €100-€160/per peak day MWh. CER should consider asking BGN to hold a public workshop to explain the assumptions underpinning its calculations and present worked up examples for Inch, Bellanaboy, and Shannon entry points.

- To provide information on any potential uplift the CER may choose to impose on any reserve prices as a mitigation measure for projected under-recovery;

- "common charging", please provide a list of options for consideration as to how this mechanism might be implemented.

IOOA consider that the inclusion of the IC into the onshore system raises concerns with respect to the core principle of avoiding cross-subsidies and discrimination. Finally the IOOA consider only when further information such as that referenced above is provided, will their members be in a position to assess the commercial impacts and provide a more comprehensive response.

Manx Electricity Authority (MEA) offer their broad support in principle for the proposed solution, and note with approval the explicit recognition in the paper "the planned changed to the IC tariff structure will ensure that the position of the Isle of Man is not unduly affected". MEA recognise that there is still considerable work to undertake before implementation of any solution in 2014, and that much of 'the devil may well be in the detail'. MEA look forward to engaging constructively in the process and detailed discussions to come.

National Electricity Association Ireland (NEAI) welcomes the proposed high level principles and a proposed high level approach but consider this very much the first step in the solution being proposed by the CER. NEAI consider that while these principles and approach may be capable of achieving a solution compatible with NEAI's position, the proposed decision paper does not provide respondents with sufficient detail to enable them to make substantive comments on the proposed approach at this stage.
NEAI consider the process to be iterative and that the outstanding issues such as;

- the methodology for setting the regulated entry tariff;

- the auction model;

- o the treatment of under/over recoveries;

- o periods of review; and

- o implications for future gas market developments, including new entry points and market integration.

will be part of the final solution. NEAI are keen to engage with the CER throughout the process to implement a stable, timely and sustainable model that continues to facilitate market development.

PSE Kinsale Energy (PSE) supports the position outlined in the IOOA response. PSE is surprised that the CER has issued a 'proposed decision paper' proposing LRMC considering it has not been mentioned in any previous consultations. PSE believe this is a radical change and consider the CER has provided inadequate information to determine how the methodology will affects PSE's storage and production business.

PSE requests the CER to complete a full and proper consultation on LRMC. This consultation needs to provide details on the LRMC tariff and calculations for each entry point such that the methodology is fully reasoned and justified and there is no ambiguity.

PSE goes on to say that in the absence of adequate information to review the LRMC proposal, PSE has the following observations:

- o The UK in its application of LRMC to its onshore networks base does not include the two interconnectors from the UK to the continent as part of its onshore network base.

- o The Irish system has two entry points (increasing to three). In contrast the UK has multiple entry points with some of these being potentially constrained. THE LRMC in the UK provides investment signals. Considering excess capacity in the Irish market, the LRMC method of calculating tariffs may not be appropriate.

- o UK based model attempts to achieve full cost recovery by using LRMC as a scaling factor for tariffs at each entry and exit, however, the CER is proposing to set the reserve prices at LRMC. This is not cost reflective and contravenes EU Directive No. 715/2009 as it does not plan to recover the full regulated revenues through reserve prices.

Safety Before LNG (SBLNG) welcomes the CER's proposed decision. SBLNG made the following high-level comments. If there is significant difference between the proposed and actual decision, then this should go back to the public for consultation. SBLNG are concerned with concerted lobbying by local Kerry based politicians to try and force Minister Rabbitte to give direction to the CER which would be favourable to Shannon LNG but against consumer interest. SBLNG believe any final decision by the CER should have as prime goals the consumer interest with no barriers to fair competition between different suppliers into the Irish market and that the cost of the interconnectors should be shared out among all suppliers proportional to their market share. SBLNG make a final point that they are especially concerned that none of the Shannon LNG assets become part of the transmissions system regulatory asset base, stating this would amount to indirect state aid to the proposed LNG terminal because Ireland already has access to LNG via the UK market.

Shannon Foynes Port Company (SFPC) has concerns regarding the consents process and diversity and security of supply. SFPC note that the Shannon LNG project received planning in 2007 (within 6 months under Strategic Infrastructure Legislation) and it was not until January 2011 that the CER consulted on fundamentally changing the future treatment of the interconnectors. SFPC also note that with time delays in the consents process coupled with uncertainty caused by long drawn out consultative reviews, could act as a barrier to new entrants to the market.
With regard to diversity and security of supply SFPC state that with the advent of Corrib, the continuance of interconnector transmitted gas and Shannon LNG there will be significant additional competition in the Irish gas market which should actually drive the cost down for the consumer. However, it appears as a consequence of the preferred option emanating from the CER consultation paper that Irish based shippers will be liable for the cost of the interconnectors, even though they may never use them. SPFC believe the ultimate implication is that the Irish consumer could suffer higher gas costs into the future as costs are being unnecessarily transferred on to potentially new sources of gas notwithstanding the Article 41 of the Gas Directive prohibits cross subsidies. SPPC finally notes that privately funded projects such as Shannon LNG should be embraced as in additional to providing competition; such projects provide improved security of supply without adding to the RAB.

Shannon LNG (SLNG) consider the Proposed Decision Paper, if adopted with little or no change, will do nothing to bring regulatory certainty to the market, but rather increase uncertainty and continue it for an indeterminate period of time. SLNG consider this uncertainty continues to have a serious impact upon their business. SLNG state "LRMC is only appropriate for designing tariffs where there is congestion in the transmission system, a corresponding demand for new capacity and long term contracts are in place to underwrite capacity expansions." "The CER now intends to apply the tariff methodology developed for a congested pipeline system (CER/11/206) to an uncongested one (CER/12/013). SLNG believes that after 15 months of consultation that the industry deserves a final decision on the matter. SLNG respectively requests that the CER make this final decision no later than April 2012.

SLNG believe the CER's Proposed Decision is economically inefficient, greatly increases regulatory uncertainty, is not cost reflective, protects the state owned pipeline company from commercial realities, has not been shown to be in the consumer's interests and discriminates against non-Great Britain suppliers of gas to Ireland, who do not use the interconnectors, by forcing them to pay part of their competitors' transportation costs. SLNG believe proposal put forward by them (where interconnector tariff would be set at a level that reflects actual cost incurred, as it has been historically, but does not increase if interconnector throughput declines), if adopted, would mean gas prices would be lower than they would be otherwise be due to the benefits of bringing real competition to the Irish market.

Further SLNG comments:

The CER does not explain why it has rejected the other Options with sufficient, or any, reasons such as to enable SLNG to understand and comment.

The CER has failed to explain why the merger of the regulatory asset base (RAB) of the onshore system and the Interconnectors is required, or the legal and regulatory rationale for such a merger. SLNG believe it is not clear on what basis the CER has the statutory authority to change the long standing Irish government policy that the interconnectors are designated as "interconnectors", and are separate and distinct from the onshore system.

The CER's Proposed Decision would involve SLNG paying a tariff which will, in part or in totality, defray the capital and operating costs of the interconnectors. SLNG estimate this cost to be in the region of €85 million per annum, which will in effect cross subsidise the cost of transporting gas from Scotland to Ireland.

SLNG considers that the proposed new tariff structure discriminates against SLNG, Corrib and others but specifically against SLNG. SLNG believe the tariff structure will be a barrier to entry, and will have an impact on competition and consumers.

SLNG does not expect the current tariff arrangements to remain in place indefinitely. However, SLNG believe that the terms, conditions and duration of the rTPA Exemption that was granted to SLNG by the CER in 2010 has given rise to reasonable and legitimate expectations. SLNG also argue that the proposed decision would, if implemented, constitute an infringement of SLNG (and its shareholders) property rights. SLNG also further the state aid argument and make a comment "it is not clear that the CER has the statutory power to make the Proposed Decision". SLNG believe there in no basis in law for the CER to direct any entity to levy charges upon Shannon LNG Energy Limited.

SLNG state "The CER must, at a minimum:

- o Ensure that the ultimate decision on tariffs for the interconnectors is understandable to industry participants, i.e. so that the industry participants are in a position to understand how and why the decision was made and assess how it affects them.

- o Ensure that comprehensive data is made available to industry participants so they are in a position to assess the full economic and financial impact of the CER's decision on their business.

- o Provide justification for the decision; including the provision of adequate information as to why the matter was decided as it was and what conclusions were reached on the 'principal; important controversial issues', disclosing how any issue of law or fact was resolved.

Shell E&P Ireland (SEPIL) prefers a solution that:

- o Avoids cross-subsidies and unfair discrimination between entry points;

- o Is based on a clear, reasoned, and transparent methodology;

- o Aligns with EU legislation regarding the basis for which tariffs for access should be set in particular that of 'cost reflectivity' at each entry point;

- o Avoid distorting gas flows between Irish and GB markets that would potentially increase dependence on a single source of supply and at the expense of incentives to encourage diversity of supply.

Regarding the proposed decision paper SEPIL recommend a comprehensive consultation process up to the target implementation of October 2014. SEPIL comment that the paper does not contain enough information for them to adequately access the commercial impact on their business. SEPIL ask that the CER organise another workshop that would focus on worked up examples of the LRMC methodology for all entry points. SEPIL also urge the CER to mandate the TSO to maintain complete transparency in relation to this.

Statoil (SEIR) reiterates its support for model which defers recovery of costs of the ICs until such time as utilisation again increases.
SEIR questions the CER's disregard for previous consultations. SEIR believe the proposed decision paper appears to protect BGE's regulated rate of return at the expense of indigenous producers. SEIR is concerned that this risks creating cross subsidies and discriminates against indigenous producers.
SEIR would like to further understand the legal implications of moving offshore assets to the onshore asset base.

SEIR recognises the concern that costs to consumers must not be unduly increased but to do so at the expense of producers who are investing inter alia to contribute to security of supply for Ireland is fundamentally wrong in that it (a) unfairly penalises existing gas producers or those who already have projects underway and (b) present a barrier to future competitive sources of gas supply.

SEIR proposes more time is allowed to all stakeholders to thoroughly consider the implications of the proposed decision paper and to make adjustments where necessary. SEIR request that in the interests of following due process that an impact assessment is undertaken to allow stakeholders to fully understand the implications of the new proposals. SEIR make the final point that given the European Framework Guidelines on Tariff Structures is being consulted upon, it would seem prudent to follow that consultation and the European Network code, prior to implementing changes in Ireland, to ensure that the Irish tariff regime is harmonised with the European regime, which will ultimately take precedence.

Tarbert Development Association (TDA) wonders if the CER has confirmed with Minister Rabbitte that it (CER) has the authority to change such Government Policy. TDA make the comment that the CER is in effect seeking to protect the commercial interests of BGE as it is ensuring that they (BGE) continue to receive revenue from what has transpired to be a poor policy decision on their part to invest in IC2. TDA contend that the CER in *NOT* fulfilling its statutory obligations to the people of this state. Finally TDA ask that the decision of the Regulator must be open, transparent and equitable and must avoid any discrimination against new suppliers of gas at new entry points now and in the future

Vayu would like to highlight that any new regime should be transparent and provide regulatory certainty to the market for the foreseeable future. Vayu recognise certain merits to the proposed decision to move to LRMC, however are somewhat hesitant to fully endorse the move.
Vayu highlighted a number of points which they feel should have been dealt with in the paper:

- If the CER was aware that the current approach would not be fit for purpose as soon as new supply sources come on stream why did it not change to the proposed structure at the first opportunity?

- This appears to be principles based change in approach without much empirical evidence.

- No real alternative to LRAIC was fully explored. The material on LRAIC is over 30 years old and was used for the water industry. Other methodologies have been developed in the intervening period i.e. ICRP methodology used for the electricity transmission system in GB.

- There is no explanation of the subsequent impact on exit tariffs at transmission level. The EU recommends that the same methodology should be used for both entry and exit level.

- The CER should also have made reference if it proposes to change the approach to tariff setting for the distribution system and if no change is being tabled then why not? An explanation is warranted.

Vayu make the point that if the time horizon chosen is say 20 years, then BG Networks should adopt the same depreciation policy for its transmission networks.
Vayu considers a 50/50 split in revenues will not be viable given the limited number of entry points and the associated LRAIC of each entry point via á vis at exit level.
Vayu note that the entry point to the Irish system will be Moffat, but would like clarity as regards where exactly this point is as this will have a major bearing on both entry and exit tariffs. Vayu understands that the structure required for twinning costs would be downstream from Moffat, and would therefore be part of the onshore system and consequently should be excluded from the LRMC calculation.

Vermillion Energy (VE) is "highly concerned that their responses to the consultation paper CER/11/112 have been disregarded and a new path, bereft of consultation with any interested parties, presented in this decision paper as a fait accompli."VE feel it is important the CER take a logical approach, building on previous consultations rather than scrapping old ones and starting afresh.
VE respects BGE's assertion that stranding costs is not an option, but they reiterate their suggestion that a "bank" for unrecovered costs could be created. VE support the IOOA in their call for a clear, detailed timeline, and more information on the potential processes which the CER believe are necessary, commenting "without them, we are unable to offer a more substantive response".
VE suggest a workshop to be held to work through examples of LRMC for all Irish entry points.

Appendix 2: Oxera Report to CER on Implications of Stranding Interconnectors

Executive summary

It is understood that Ireland's reliance on Bord Gáis Network's (BGN) interconnectors with Scotland for supplying gas is expected to decline in the future, as new sources come on stream from the Corrib offshore gas field and/or from the potential Shannon liquefied natural gas (LNG) project.[17]

Under the CER's current regulatory regime, the interconnectors are included within BGN's regulatory asset base (RAB), and are used to determine the entry tariff. It is understood that the interconnectors currently comprise approximately 20% of the RAB. However, if the throughput on BGN's interconnectors declines substantially, this would be likely to lead to an increase in the unit entry tariff, placing upward pressure on wholesale gas prices. In light of this, the CER has set out options for reforming the regulatory regime for the interconnectors in its February 2012 proposed decision paper.[18]

– **Stranding of the unused element of the interconnectors**. Under this option, the customer would no longer underwrite the investments. This option is not recommended by the CER on the basis that: any stranding of assets would represent poor regulatory practice; it may create significant uncertainty; it may lead to an increase in the rate of return required by investors in new infrastructure; and it may conflict with the CER's duty-to-finance obligation.

– **Cap on the interconnector tariffs**. Under this option, the interconnector tariff would be capped at an 'efficient' level, with the remainder of revenues recovered at exit. The CER suggests that the cap could be determined on the basis of any of the following: the existing interconnector tariff; a tariff based on only one of the two interconnectors; a tariff based on the current throughput on the two interconnectors. This option is not put forward by the CER on the basis of reliance on historical costs and the likely resulting upward pressure on gas tariffs.

– **Removal of the entry tariff**. In contrast to the current regulatory regime, this option would involve transmission network costs being recovered through a regulatory regime that does not take into account the geographic source of the gas purchased by the shipper. This option is not advanced by the CER as it would lead to the separation of the tariffs from the take-up of gas at alternative entry points into the gas system.

– **Tariffs estimated according to the long-run average incremental cost (LRAIC) of transporting gas at each entry point**. In its proposed decision paper, the CER recommends that transmission entry tariffs could be determined by auctions of capacity at each entry point, with the reserve price set by the regulated tariff. This tariff could be based on estimated LRAICs at the point of entry, differentiating between entry points.

It is understood that a recurring issue in the debate so far has been the case for or against stranding part of BGN's investment in the interconnector assets to the extent that the use of these assets is expected to decline in the future. One of the arguments advanced by the

[17] It is understood that currently two gas interconnectors provide connections between the gas market in the Republic of Ireland and Great Britain. However, owing to system constraints on the Scottish onshore side, one gas interconnector would be sufficient to serve the current throughput.

[18] CER (2012), 'The Regulatory Treatment of the BGÉ Interconnectors, Proposed Decision Paper, CER/12/013', February 17th.

CER against partial stranding of BGN's interconnectors is that this would significantly increase the perceived riskiness of BGN's investments compared with the current regulatory regime, and may have implications for BGN's rate of return.

Given this context, this report considers:

– whether there is a case to argue that stranding BGN's interconnectors on a material scale could affect the cost of capital; and

– if this is the case, the possible order of magnitude in terms of the impact on the rate of return.

In order to address these questions, evidence from the literature has been considered, as well as regulatory precedents.[19]

What is the likely impact of stranding BGN's interconnectors on the estimate of BGN's cost of capital?

Since it is understood that the construction of BGN's interconnectors was approved by the government prior to the CER having responsibility for gas regulation, any stranding of these costs may be viewed as constituting a breach of the regulatory 'compact' or agreement. Based on evidence from the literature, this is likely to increase investors' perception of risk, with two possible effects:

– it may affect the estimate of BGN's cost of capital; and/or
– it may affect BGN's expected cash flows, and, therefore, it may be factored into an estimate of the rate of return that exceeds the cost of capital.

Before discussing these possible effects in more detail, it is important to consider the distinction between the concepts of the cost of capital, the allowed rate of return and the planned rate of return that have been adopted for the purposes of this report (as set out in the box below).

Distinction between the concepts of the cost of capital, the allowed rate of return and the planned rate of return

– **The cost of capital** represents the rate of return required by investors, in light of their perception of the risks associated with the investment. For example, Oxera has estimated the midpoint of BGN's real pre-tax cost of capital to be 6.7%.[20]

– **The allowed rate of return** is the rate of return allowed by the regulator. In theory, it incorporates the downside risk of asset stranding.

– **The planned rate of return** represents the rate of return expected by investors. It represents the average of the allowed rate of return and the lower outturn rate of return that would materialise in the (unlikely, but possible) event that the assets are stranded, weighted by the likelihood that stranding occurs. The resulting estimate of the allowed rate of return should align closely with the estimate of the cost of capital.

[19] An assessment of the regulatory options proposed by the CER for BGN's interconnectors is outside the scope of this report.

[20] For further details, see Oxera (2012), 'What is the cost of capital of Bord Gáis Networks?', prepared for the Commission for Energy Regulation, May 21st; available at http://www.cer.ie/en/consultations.aspx?type=gas&article=7c6755c1-140a-433b-b209-468b9e7f0ac1.

Impact on BGN's cost of capital

The rate of return required by investors (ie, the cost of capital) depends on investors' perceptions of the level of risk exposure. Intuitively, any increase in risks associated with investment in BGN's interconnector assets, as a result of potential asset stranding, would be expected to lead to an increase in the cost of capital.

Under the framework of the capital asset pricing model (CAPM), which is commonly adopted by regulators, including the CER, and has been adopted by Oxera in order to estimate BGN's cost of capital, only non-diversifiable (ie, systematic) sources of risk will affect the cost of capital. However, there is limited empirical evidence of the impact of the risk of stranding on the systematic risks faced by companies such as BGN.

Impact on BGN's expected cash flows

The risk of partly stranding BGN's interconnector investments is asymmetric in nature, as it creates a risk for a substantial loss of revenue without any equivalent opportunity for higher revenues. Asymmetric risk may affect expected future cash flows without materially affecting the cost of capital. This impact is important, since it implies that investors will expect to earn an actual return below that required to compensate them for investing in the asset, even if the regulator sets the allowed return at the cost of capital.

In order to align investors' expectations of future returns more closely with the cost of capital, in the absence of a credible guarantee on the recovery of all potentially stranded costs, investors may require an allowed rate of return that exceeds the estimate of the cost of capital. Theoretically, the allowed rate of return would be estimated such that the resulting planned rate of return is equal to the estimate of the cost of capital. However, in practice, it is not possible to quantify the impact of asset stranding on investors' expectations with any degree of robustness.

This illustrates that, in theory, in the absence of a guarantee on the recovery of potentially stranded costs, investors may require compensation for the risk of possible stranding. This would involve an upward revision to expectations of future cash flows that would prevail in the event that no asset stranding occurs, through an allowed rate of return that exceeds the estimate of the cost of capital.

In light of the challenges involved in robustly quantifying the impact of asset stranding on the rate of return, only a few papers have attempted to quantify the impact. Notwithstanding this caveat, the literature considered indicates that potentially stranding a proportion of the costs of BGN's interconnectors could lead to an estimate of BGN's allowed rate of return that is higher than Oxera's estimate of the midpoint of BGN's real pre-tax cost of capital of 6.7%.

Conclusions

There is evidence that investors would be likely to require an allowed rate of return over and above the estimate of the cost of capital to compensate for the potential risk of stranding part of the investments in BGN's interconnector assets.

A review of the most relevant regulatory precedents has shown that, in the majority of cases, regulators have allowed stranded costs to be recovered. In particular, regulatory authorities in the USA and the EU have allowed the recovery of these costs in the transition to greater competition, especially in the electricity generation sector, on the basis that it is likely to be more economically efficient to allow the stranded costs to be recovered.

Therefore, if, under the CER's proposed options for BGN's interconnectors, the impact of any potential stranding is not recovered through charges elsewhere, this could have financeability implications. Given the CER's duty-to-finance obligation, if part of the investment in BGN's interconnector assets were potentially stranded under the options proposed by the CER, the allowed rate of return would need to be estimated at a premium over and above the estimate of BGN's cost of capital. This would be important in ensuring appropriate incentives to invest, such that the planned rate of return aligns with the estimate of the cost of capital.

Given that this does not appear to reflect how prices have been set in the past (ie, no premium has been assumed), investors may be expected to respond negatively to the potential for the interconnector assets to be partly stranded, unless confidence can be established through a clear indication of how the regulator will allow the recovery of future investments.

Contents

1 Introduction

Stranded costs typically arise as a result of past sunk (ie, irreversible) investments undertaken by an incumbent utility under an explicit or implicit contract (the 'regulatory compact') that the utility can recover its expected costs; however, these costs later became unrecoverable as a result of the regulatory authority introducing greater competition (which leads to lower prices). Broadly speaking, stranded costs may be viewed as the difference between the book value and the market value of the incumbent utility's assets (although this may also reflect other aspects, such as financial distress).

There are a number of arguments in support of allowing the incumbent utility to recover its costs, for reasons of efficiency and equity. For example, equity reasons are commonly used as a justification for allowing stranded costs to be recovered in the transition to competition. If the recovery of these costs is not allowed, this may also result in inefficient outcomes. Where an otherwise efficient incumbent is unable to earn the necessary return on its stranded assets, the associated increase in perceptions of regulatory risk by investors is likely to increase the required level of returns. All else being equal, this may lead to the level or composition of future investment falling below the socially desirable (or 'optimal') level.[21]

The next section focuses on the issues surrounding one of the efficiency arguments—specifically, the implications of stranding BGN's interconnector assets for investors' perception of risk. This issue is examined taking into account evidence from the literature. In section 3, regulatory practice is considered in order to assess the impact of different regulatory treatments of asset stranding (with details set out in the appendix). Section 4 provides an overall conclusion to the report.

[21] This may also result in inefficient firms entering the market, as new entrants would not shoulder the same 'burden' as that imposed on the incumbent. For example, to the extent that the stranding of assets imposes higher costs on the incumbent utility, this may lead to greater inefficiency by new entrants. This implies that there may be effective market competition by inefficient entrants, thereby increasing costs to consumers in the long run.

2 Implications for risk and investors' decisions

The allowed rate of return should be estimated such that investors can expect to earn a benchmark level of return that is equivalent to the cost of capital—ie, the rate of return required by investors.[22]

Good regulatory practice is to consider the risks affecting future cash flows by assessing their variability under different scenarios, with each scenario weighted by the likelihood that the scenario materialises in the future. The spectrum of possible cash flows weighted by their probability represents the expected cash flow.

In this context, it is important to distinguish between the concepts of the cost of capital, the allowed rate of return and the planned rate of return that have been adopted for the purposes of this report, as summarised in Box 2.1.

Box 2.1 Distinction between the concepts of the cost of capital, the allowed rate of return and the planned rate of return

– **The cost of capital** represents the rate of return required by investors, in light of their perception of the risks associated with the investment. For example, Oxera has estimated the midpoint of BGN's real pre-tax cost of capital to be 6.7%.[23]

– **The allowed rate of return** is the rate of return allowed by the regulator. In theory, it incorporates the downside risk of asset stranding.

– **The planned rate of return** represents the rate of return expected by investors. It represents the average of the allowed rate of return and the lower outturn rate of return that would materialise in the (unlikely, but possible) event that the assets are stranded, weighted by the likelihood that stranding occurs. The resulting estimate of the allowed rate of return should align closely with the estimate of the cost of capital.

The above distinction is of particular importance when assessing the potential implications of increases in perceived risk, as a result of regulators not allowing the utility to recoup stranded costs (as explored further in the sections below).

2.1 The regulatory compact

In general, regulated utilities undertake investments to pursue public policy goals (eg, to increase energy from renewable sources) or deliver outputs (eg, secure supply), with the expectation that investors will be allowed earnings that are sufficient, in the long run, to recoup their capital together with a competitive rate of return on their investments.

In the commercial context, investors weigh the probability of upside outcomes (ie, when earnings are above the target level) and downside outcomes (ie, when earnings are below the target level). If the resulting expected earnings (ie, average earnings weighted by the

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[22] See, for example, Brealey, R.A. and Myers, S.C. (2008), *Principles of Corporate Finance*', McGraw Hill International, p. 15.

[23] For further details, see Oxera (2012), 'What is the cost of capital of Bord Gáis Networks?', prepared for the Commission for Energy Regulation, May 21st; available at http://www.cer.ie/en/consultations.aspx?type=gas&article=7c6755c1-140a-433b-b209-468b9e7f0ac1.

probability of the different possible outcomes) are at least as high as the competitive benchmark, investors would be likely to undertake the investment.

In the regulatory context, the upside is generally constrained by regulatory rules: utilities will generally not be able consistently to earn a rate of return above the allowed level over the long run, although temporary departures due to cost efficiency are possible. Complementary to this ceiling imposed on returns is the regulatory practice to allow for the mitigation of a number of sources of downside outcomes (eg, increases in efficiently incurred costs). This is the 'regulatory compact' that allows regulators to reconcile ceilings imposed on earnings with the requirement to allow companies to earn the competitive level of return on their investments.[24]

Since it is understood that the construction of BGN's interconnectors was approved by the government prior to the CER having responsibility for gas regulation, not allowing the recovery of stranded costs can be viewed as a breach of the regulatory compact.[25] The evidence in the literature, with a few exceptions,[26] suggests that this is likely to increase investors' perception of risk.[27] The main implications of this increased perception of risk can be twofold:

– **the cost of capital may be affected**: the risk of asset stranding may affect the cost of capital of the regulated businesses;

– **the allowed rate of return may be affected**: the risk of asset stranding may affect investors' expected cash flows—if the regulator shows willingness potentially to strand assets and not compensate elsewhere for this risk, investors may recognise that the planned rate of return may be lower than the estimate of the cost of capital. In order to ensure that the planned rate of return aligns closely with the estimate of the cost of capital, the allowed rate of return needs to exceed the estimate of the cost of capital.

These are considered further in the following sections.

2.2 Possible impact on the cost of capital

The cost of capital depends on investors' level of risk exposure. Therefore, intuitively, any increase in the risk associated with investments in utility assets, as a result of the risk of possible stranding, would be expected to lead to a higher estimate of the cost of capital. However, the extent to which this is the case should be assessed in the context of the type of risk that affects the cost of capital. The capital asset pricing model (CAPM) is commonly adopted by regulators to estimate the allowed rate of return (and it has been adopted by Oxera for the purposes of estimating BGN's cost of capital).

– Under the CAPM, the cost of equity is driven by non-diversifiable (systematic) risk—ie, risks that investors cannot eliminate by holding a diversified portfolio of investments. These risks include macroeconomic/market-wide risks that affect all companies' returns, such as the economic cycle, commodity prices and exchange rates. Under the CAPM,

[24] See Baumol, W. and Sidak, J. (1996), 'Transmission pricing and stranded costs in the electric power industry', AEI, chapter 8.

[25] See ibid. In the specific case of BGN, there may be additional objections to the risk of asset stranding in light of the state ownership.

[26] See, for example, Stelzer, I.W. (1994), 'Stranded Investment: Who pays the bill?', March, remarks delivered at Southwestern Electric Exchange, Washington D.C.

[27] See, for example, Baumol and Sidak (1996), op. cit.; Kolbe, A.L. and Tye, W.B. (1996), 'Compensation for the risk of stranded costs', *Energy Policy*, **24**: 12; and Kolbe and Borucki (1998), op. cit.

these risks are measured by the 'beta', which reflects the correlation of the risk of the investment with the risk of a portfolio of all securities (the 'market portfolio').

– Under the CAPM, non-diversifiable (systematic) risk will also influence the cost of debt. However, the cost of debt also reflects other factors, such as cash flows promised to debt holders, adjusted for the probability of default, in addition to supply, demand and liquidity factors.

By contrast, investment-specific risks can be diversified, and, as such, would not lead to a higher cost of capital. Therefore, under the CAPM framework, the cost of capital would be affected only if the risk of stranding costs were systematic.

Theoretically, it is not clear-cut whether the risk of stranding is systematic. On the one hand, it could be argued that stranding risk is specific to the utility and therefore entirely diversifiable, and should not affect the cost of capital (ie, the risk is not systematic). On the other hand, it could be argued that there is an element of systematic risk given that the likelihood and magnitude of assets being potentially stranded may be larger in economic downturns as regulators seek to shield consumers from the costs of essential infrastructure. That is, stranding costs may be partly correlated with other macroeconomic risks.

There is limited empirical evidence about the impact of stranding costs on a utility's systematic risk.[28] The evidence that is available is predominantly specific to the market context in the USA, and is therefore unlikely to be directly applicable in the case of BGN.

It is possible that the risk of potentially stranding BGN's interconnectors may be partly systematic, and, as such, may affect BGN's cost of capital. However, the evidence to support this is limited, and the impact on the cost of capital has not been estimated in previous empirical studies.

2.3 Possible impact on the allowed rate of return

The risk of stranding investments is asymmetric in nature since it creates a risk for substantial loss without any equivalent opportunity for gain.[29] Asymmetric risk may affect the rate of return.[30] This impact is important since it implies that investors may expect to earn an actual return below that required to compensate them for investing in the asset, even if the regulator sets the allowed return at the cost of capital.

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[28] Besanko, D'Souza and Thiagarajan (2001) examined stock price reactions over the period leading up to and including the passage of the 1992 Energy Policy Act (EPACT), which, among its many provisions, allowed for independent power producers to enter the wholesale electricity market. The deregulation of electricity markets carried a risk that investments would be stranded for incumbent utility companies. However, the study found that investor reaction was largely neutral to these events. In its analysis of the potential impact of the introduction of EPACT, Impson (2007) concluded that, although estimates of the beta for US utilities rose initially between 1992 and 2000—potentially indicating an increase in utilities' systematic risk related to the liberalisation process—the effect did not last. For further details, see Besanko, D., D'Souza, J. and Thiagarajan, S. (2001), 'The effect of wholesale market deregulation on shareholder wealth in the electric power industry', *Journal of Law and Economics* and Impson, M. (2007), 'Changes in Electric Utility Risk Levels Following EPACT 1992', available at: http://69.175.2.130/~finman/Orlando/Papers/ChangesinElectricUtilityRiskLevelsFollowingEPACT1992.pdf.

[29] See, for example, Kolbe and Tye (1996), op. cit.

[30] Although modifications of the CAPM have been proposed to capture the asymmetric risk arising from the more general regulatory risk—see, for example, Grayburn et al. (2002), 'A report for the National Audit Office on regulatory risk', section 4.2.2.

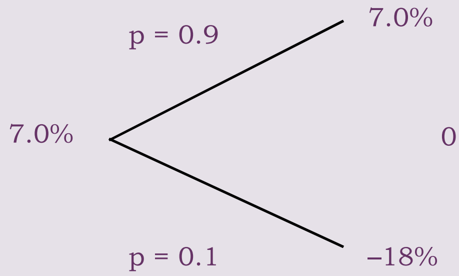
In order to align investors' expectations of future returns with the cost of capital, investors may require a credible guarantee on the recovery of all stranded costs, or a premium over and above the cost of capital to compensate for the stranded costs.[31] This suggests that in order to compensate for the risk of asset stranding, the allowed rate of return may need to be set at a premium over and above the cost of capital. This is supported by empirical evidence; although few papers have attempted to quantify the impact on the allowed rate of return.[32]

The possible impact of stranding assets on the rate of return is illustrated in Box 2.2.

Box 2.2 Illustration of the possible impact of stranding assets on the rate of return

For the purposes of this illustration, assume that the utility provider's cost of capital is estimated to be 7%. Furthermore, it is assumed that investors assume that the probability that the utility provider is faced with stranded assets is 0.1, and that the resulting write-off would lead to a 25% decrease in actual returns. In addition, it is assumed that no compensation is provided by the regulator for this asymmetric risk.

Under these assumptions, the expected rate of return would be approximately 4.5% (ie, the average of the rate of return in the event that the assets are stranded and the rate of return in the event that the assets are not stranded, weighted by the probability of asset stranding occurring). This estimate of the expected rate of return is far lower than the estimate of the cost of capital (ie, 7%).



$$0.1 \times -18\% + 0.9 \times 7.0\% = 4.5\% < 7.0\%$$

To compensate investors for the risk of possible stranding, expectations of future cash flows would need to be revised upwards. This would involve estimating an allowed rate of return that exceeds the estimate of the cost of capital, such that the planned rate of return is equal to 7%. In the stylised example above, the allowed rate of return would have to be increased to approximately 10% to ensure that the planned rate of return aligns with the estimate of the cost of capital.

In this example, the investor is assumed to be neutral to the specific risk of stranding.

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31 See, for example, Kolbe, A.L., Tye, W.B. and Myers, S.C. (1993), *Regulatory risk: Economic principle and applications to natural gas pipelines and other industries*, Kluwer Academic Publisher.

32 For further details, see Kolbe and Borucki (1998), op. cit. The authors concluded that the risk of cost stranding, as a result of the restructuring of the Californian electricity industry in April 1994, might require a premium to be applied to the cost of capital in order to provide some insurance against the probability of stranded costs.

If BGN's interconnector assets were to be stranded, this would be likely to signal to investors that the CER is prepared to strand investments ostensibly undertaken with government support. Furthermore, this may have implications for other sectors, such as electricity infrastructure.

The risk of stranding BGN's interconnectors may result in investors incorporating the risk of asset stranding into their assessments. All else being equal, investors may require an allowed rate of return that exceeds the estimate of the cost of capital in order to undertake future investments. This would ensure that the allowed rate of return aligns closely with the cost of capital.

A review of the most relevant literature suggests that investors would require an allowed rate of return over and above the cost of capital, if the costs associated with BGN's interconnectors were potentially stranded. Although, it should be noted that few studies have quantified the impact of asset stranding on the rate of return.[33]

[33] For further details, see Kolbe and Borucki (1998), op. cit.

3 Evidence from regulatory precedents

In addition to considering evidence from the literature, the most relevant regulatory precedents have been reviewed.

In this section, a number of case studies from regulation in the UK, Europe and the Americas are presented. When assessing the approaches adopted by other regulators, it is important to bear in mind the circumstances leading to the stranding of the assets, in order to provide context to the actions of regulatory authorities in different jurisdictions.

In the majority of the examples below, stranded investments have arisen as a result of the liberalisation or deregulation of the utility market. The development of the market has an obvious consequence for the incumbent companies, which, in most cases, are at a disadvantage due to excess capacity and/or previously negotiated long-term contracts that are no longer applicable in the new market place.

3.1 Overview

In general, regulatory authorities in the USA and the EU have allowed the recovery of these costs in the transition to greater competition, especially in the electricity generation sector, on the basis that it is likely to be more economically efficient to allow the stranded costs to be recovered. In contrast, the evidence from those limited examples of stranded costs in the UK is more mixed. (For further details, see the table in the appendix.)

The European Commission has explicitly laid out guidelines regarding the recovery of stranded costs, as documented in the European Parliament and Council Directive 96/92/EC of December 19th 1996. Several European utilities have been compensated, at least in part, for costs arising from plants having excess capacity or no longer being profitable. The compensation has come in the form of a surcharge on transmission consumers or a competitive transition charge (CTC) as detailed in the table in the appendix.

In the UK, there are few examples of utility companies being faced with stranded costs. Even in these relatively rare cases, there is no conclusive evidence of UK regulators allowing for the costs relating to stranded assets to be recovered. However, there is also no clear evidence of investors perceiving this to be an additional asymmetric risk.

In the USA, there are some examples of regulators allowing some of the costs that would otherwise be stranded (by passing these costs on to consumers). In the US context, stranded costs arose, as they did in Europe, primarily as a result of liberalising the energy markets. Cases involving the treatment of stranded costs in the US electricity sector appear to have been complex—in large part, because of the difficulties associated with defining the appropriate level of stranded costs that should be recovered. Another significant driver of the complexity of the stranded cost recovery cases is the regulatory authorities' desire to achieve objectives that may be sometimes be mutually incompatible to some extent, including short-term tariff reductions, increased retail and generation competition, short transition periods to full retail and wholesale competition, and recovery by utilities of their efficiently incurred stranded costs.

In South America, although there are examples of the recovery of stranded costs being allowed in principle, it is often unclear whether the utility has received compensation for these costs. The examples from South America differ somewhat from the case of BGN's interconnectors, in that the source of the risk is not strictly regulatory; rather, it predominantly comes from general political risk drivers. However, this has not prevented investors from returning to these countries later to invest in infrastructure. For example, investors returned to Argentina a few years after it was declared as having defaulted on its national debt, and after a number of investments by foreign providers of finance were stranded (the most intense period of the economic crisis in Argentina was between 2002 and 2003).[34]

The recovery of foreign investment in countries such as Argentina in 2010 may be a signal of investors progressively assessing the country as less risky, or, more simply, a sign that returns are sufficient to compensate the risks of stranding. There does not appear to be clear evidence as to the main drivers for investors returning to invest in countries that are characterised by a relatively high risk of stranding assets—if historical behaviour is used as a guide to assess future risk—and where investors may not be compensated, either fully or partly, for these risks. There may be various reasons for this, which may differ across countries, one of which may be that investors perceive higher risks only in the short to medium term.

While there is no single common approach that has been adopted by regulators worldwide, typically in Continental Europe and the USA the incumbent utility has been compensated for stranded costs. While, in the UK, there are very few examples of utility companies being faced with stranded costs.

A decision to strand part of BGN's investments in the interconnectors is likely to result in an increase in the perception of risk.

[34] In particular, in 2010, foreign investments partially recovered. For further details, see Caballero, A. (2012), 'Inward FDI in Argentina and its policy context 2011', Vale Columbia Center, available at: http://www.vcc.columbia.edu/files/vale/documents/Argentina_IFDI_-_25_Jan_12.pdf.

4 Conclusions

The evidence presented in this report suggests that if part of BGN's investments in the interconnectors were potentially to be stranded, future investments would be perceived by investors as having greater risk. Based on the literature reviewed in this report, investors would then require an allowed rate of return that exceeds the estimate of the cost of capital in order to compensate for this additional risk. The allowed rate of return would be higher than the estimate of the cost of capital to ensure that the planned rate of return aligns with the estimate of the cost of capital.

In general, regulatory authorities in the USA and the EU have allowed the recovery of stranded costs in the transition to greater competition, especially in the electricity generation sector, on the basis that it is likely to be more economically efficient to allow the stranded costs to be recovered.

This evidence suggests that, in the event that BGN's interconnector assets were partly stranded, investors would be likely to require a premium over and above the estimate of the cost of capital in order to invest. Therefore, if, under the CER's proposed options for BGN's interconnectors, the impact of any partial potential stranding is not recovered through charges elsewhere, this would be likely to have financeability implications. In light of the CER's duty-to-finance obligation, it would be important to ensure that BGN can attract potential investment. It would therefore be necessary to estimate an allowed rate of return for BGN that exceeds the estimate of BGN's cost of capital (of 6.7%).

Given that it does not appear that prices have been set in this way in the past (ie, no premium has been introduced), investors might be expected to respond negatively to such a move to potentially strand a portion of the investment in BGN's interconnector assets, unless confidence can be established via a clear indication about how the costs of future investments can be recovered.

Details of regulatory precedents

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
UK						
British Gas	1996	Liberalisation of the gas market and change in EU laws	The issue of stranded costs arose in the form of the 'take-or-pay' contracts: long-term 'fixed-price plus inflation' contracts with North Sea gas producers designed to ensure the security of supply by encouraging the development of new gas sources. A turn of events resulted in an over-supply of gas in Britain. As British Gas lost customers in the industrial market, it was tied into buying gas that was not needed to meet demand, and, because the spot price for gas had fallen below the contract price, British Gas faced difficulties selling the gas	British Gas was forced to renegotiate its contracts. It also committed itself to selling some of its volumes through long-term export sales contracts	None There were suggestions that the Department of Trade and Industry was considering a levy on *all* gas suppliers to pay for British Gas's take-or-pay liabilities. This was ruled out by the Board of Trade	After some investor uneasiness in 1996, the share price of British Gas rose significantly in the subsequent year. This might have been due in part to British Gas terminating or renegotiating some of its take-or-pay contracts, thus allaying fears of significant stranded costs

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
Transco	1997	Change in regulatory model to encourage competition	The Director General of Gas Supply and the Monopolies and Mergers Commission (MMC) proposed regulating storage activities under a separate cap because of the possibility that a joint cap might have a detrimental effect on the development of competition in storage. British Gas agreed to this in principle, although one of the conditions was that compensation be paid to Transco for stranded assets	British Gas claimed that, depending on the level of competition that was forecast to emerge, competition in storage would lead to a reduction in value in its storage assets from £937m to £285m–£591m	None The MMC rejected British Gas's claim, since its own calculations demonstrated that, on average, there was no expectation of stranding	n.a.

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
Continental Europe						

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
Austria[1]	2001	Liberalisation of electricity markets	The principles for liberalising the European electricity industry and completing the internal market in electricity were stipulated in the European Parliament and Council Directive 96/92/EC of December 19th 1996. It has been recognised—notably in the Directive[35]—that the gradual transition towards competition at the European level must take place under normal economic conditions, taking into account the specific characteristics of the electricity industry	The decision led to significant stranded costs in hydroelectric investments and thermal power plants	The compensation package included €458m for stranded hydroelectric investments, primarily the Freudenau plant, and another €131m to cover the operating costs of the Voitsberg III lignite-fired thermal power plant. This was to be financed through a levy on consumption for eligible and non-eligible customers, which was collected by the regional network operators, via a charge on transmission	n.a.

35 See Article 24, which allows Member States to defer application of some of the provisions of the Directive for a transitional period. The Directive stipulates that, in the event of a sudden crisis in the energy markets, where the physical safety or security of persons, apparatus or installations or system integrity is threatened, a Member State may temporarily take the necessary safeguard measures. Such measures must cause the least possible disturbance to the functioning of the internal market and must not be wider in scope than is strictly necessary to remedy the sudden difficulties that have arisen. The Member State concerned shall, without delay, notify these measures to the other Member States, and to the Commission, which may decide that the Member State concerned must amend or abolish such measures, insofar as they distort competition and adversely affect trade in a manner which is at variance with the common interest.

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
The Netherlands[1]	2001	Liberalisation of electricity markets	Same as for Austria (see above)	The resulting stranded costs related to the long-term city heating contracts and the 253MW coal gasification plant, Demkolec	The city heating stranded costs were calculated annually using a fuel-price risk analysis. The stranded costs of the Demkolec project were determined by an auction of the plant. The total compensation was €600m. To finance the stranded costs, the Dutch authorities originally proposed a surcharge as a proportion of the costs for transport and system services charged on electricity consumers, but later withdrew this financing mechanism	n.a.
Spain[1]	2001	Liberalisation of electricity markets	Same as for Austria (see above)	Stranded costs related to thermal power plants and other sources of energy	Compensation amounted to €10.4 billion split between €1.7 billion for production from indigenous coal, and €8.7 billion for other producers	There appear to have been some initial concerns from investors owing to the abolition of the CTC of the 4.5% surcharge on consumers' electricity bills. Eventually, an agreement was reached to recover these costs through the electricity rate by means of a fixed annual charge

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
Greece [2]	2002	Liberalisation of electricity markets	Same as for Austria (see above)	Liberalisation led to significant stranded costs in: operating power stations that were built before the market was liberalised; water resource management and irrigation work imposed by the Greek state; and a long-term contract requiring that, until 2006, Public Power Corporation (PPC) should supply electricity to an aluminium plant at prices that may be below the market level	Compensation granted for the three types of cost as follows: a) up to €929m for operating unprofitable power b) €324m towards the cost of water resource management and irrigation work c) up to €178m to be paid to PPC, with an annual adjustment to reflect actual losses on the long-term contract	n.a.

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
USA						
California (several companies)[3]	1994	Increasing competition in the electricity market	In 1994, California's Public Utilities Commission (CPUC) issued its 'Blue Book',[36] which set out measures to achieve a more competitive industrial structure	The interpretation of stranded costs was subject to much debate owing to a lack of any universal definition leading to uncertainty over the determination of stranded costs	The CPUC set a CTC to individual rate classes using a uniform percentage levy on expected customer bills. Some large industrial and commercial users also paid a CTC through the demand charge based on the connected capacity (kW). The CTC was collected via the distribution utility as a separate line item	n.a.
Pennsylvania Power and Light Company (PP&L)[4]	1998	Increased retail competition in retail electricity markets	A state government Act called for a phased transition to full retail competition to begin in January 1999, with all customers eligible to switch suppliers by January 2001	PP&L was required to explain how it would unbundle its generation and transportation activities in order to facilitate greater competition. In addition, PP&L was required to estimate the magnitude of its stranded assets, and the mechanism for recovery of these costs	A settlement between PP&L and Pennsylvania Public Utility Commission (PPUC) was reached that recognised the existence of nearly $3 billion in stranded costs to be recovered over an 11-year period. This compared with PP&L's original estimate of stranded costs of around $4.5 billion. Moreover, PP&L was allowed to securitise 100% of the final settlement amount and retain up to 25% of the associated savings	n.a.

[36] CPUC (1994), 'Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation', Ruling 94-04-31, San Francisco, CA, April 20th.

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
Tucson Electric Power, Arizona (TEP)[5]	1999	Greater retail access in the Arizona electricity sector	In the lead-up to the liberalisation of the Arizona market, the Stranded Cost Working Group appointed by the Arizona Corporation Commission (ACC) reported on the options available for stranded cost recovery[37]	Options submitted to the ACC by the Working Group were that the recovery of costs should be either a non-bypassable kW or kWh levy with the option of a consumer exit fee when mutually agreed upon by the utility and consumer, or a fixed entry fee. Alternatively, the Working Group recommended that the fixed or variable nature of the regime be determined on a utility-by-utility basis	In the ensuing restructuring proposals by the Arizona incumbent utilities, in 1999 the ACC approved TEP's proposal and allowed the recovery of $450m in stranded costs to be collected through a CTC based on a distribution charge. The recovery of a further of $183m in stranded costs was also allowed	Moody's placed all of TEP's security ratings under review for possible upgrade following the announcement that the ACC had approved a settlement proposed by TEP relating to stranded cost recovery and electric restructuring
Latin America						
Chile[6]	Post-liberalisation of utilities	Approach to regulation of public utilities	Model to set tariffs for each price control based on costs incurred by notional new entrant building the entire asset base from scratch	Effectively excludes all stranded assets from the asset base	None If it is assumed that the regulatory model is well-set-out and transparent, it might be argued that investors and companies are aware of the risks related to the regulatory model in place	n.a.

[37] ACC (1997), 'Stranded Cost Working Group Report to the Commission', Tucson, AZ, June 30th.

Company/ country	Year	Regulatory context for stranded costs/ investments	Description of event	Outcome	Compensation	Likely impact on investors
Azurix, Argentina[7]	2002	Renegotiation of contract	In May 1999 the province of Buenos Aires used competitive bidding to award a concession for the private provision of water services. The winning bidder, Azurix, offered $277m for the right to provide water services in three zones of the province. The concession contract also required Azurix to invest $500m in improvements and service extensions in the first five years of the concession Shortly afterwards it sought to renegotiate the contract (other firms had bid less than a tenth of Azurix's bid)	Azurix and the government respectively argued that the other side did not comply with agreed-upon terms. The government did not concede to a renegotiation. As a result, in 2002 Azurix abandoned the concession, and the government reassumed responsibility for providing water services	The International Centre for the Settlement of Investment Disputes (ICSID) awarded Azurix $156m in compensation (substantially less than the $620m Azurix originally invested and subsequently claimed in damages). It is understood that the ICSID ruling has not been compiled with[38] As at July 31st 2010, Azurix was owed more than $220m by the Republic of Argentina	n.a.
Argentina gas sector cases[8]	2002	Freezing tariffs/breach of contracts	In January 2002, Argentina passed an 'Emergency Law' which abolished the currency board that pegged the Argentine peso to the US dollar. It also terminated the right of privatised public utilities to tariffs calculated in dollars and according to the US Purchasing Power Index. All four affected companies claimed this to be a breach of the contract in place and sought resulting damages[39]	In 2007, in all four cases, tribunals established under the World Bank's ICSID rules found in favour of the companies. The damage awards, three of which exceeded $100m, were among the highest ever rendered by an ICSID tribunal	Argentina has filed annulment proceedings and to date there has been no evidence of compensation being received by the companies (some of the awards were later annulled by ICSID annulment tribunals)	n.a.

Note: n.a. denotes that sufficient information was not available to assess the likely impact on investors.
Source: [1] European Commission (2001), 'Commission Gives Green Light to "Stranded Costs" Compensation by Spain, Austria, and the Netherlands', press release, IP/01/1079, July. [2] European Commission (2002), 'Electricity:

[38] Azurix Corp. v/s The Argentine Republic (2009), 'Decision on the Application for Annulment of the Argentine Republic', ICSID Case No. ARB/01/12.

[39] These cases refer to claims by four US investors in Argentina's gas transportation and distribution utilities: Enron, Sempra, CMS and LG&E.

Green Light for Greek Stranded Costs', available at: http://www.europolitics.info/electricity-green-light-for-greek-stranded-costs-artr188075-10.html. [3] CPUC (1994), 'Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation', Ruling 94-04-31, San Francisco, CA, April 20th. [4] PP&L, Inc. (1998), 'Joint Petition for Full Settlement of PP&L, Inc.'s Restructuring Plan and Related Court Proceedings', Docket No. R-00973954, before the PPUC, Allentown PA, August 12th. [5] ACC (1997), 'Stranded Cost Working Group Report to the Commission', Tucson, AZ, June 30th. [6] CRC Series on Competition, Regulation and Development (2007), *Regulatory Economics and Quantitative Methods: Evidence from Latin America*, O.C. Omar (ed), Edward Elgar Publishing, pp. 24–7. [7] Guasch, J.L. (2004), 'Granting and Renegotiating Infrastructure Concessions: Doing it Right', World Bank Institute, January. [8] Alvarez, J., and Khamsi, K. (2009), 'The Argentine Crisis and Foreign Investors: A Glimpse into the Heart of the Investment Regime', chapter 10 in K. Sauvant (ed), *The Yearbook on Investment Law and Policy 2008/2009,* New York: Oxford University Press.