Impact assessment of policy options on incremental capacity for EU gas transmission

A FINAL REPORT PREPARED FOR ACER

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Executive summary

This report presents our findings on policy options for harmonised arrangements concerning incremental gas transmission capacity at interchange points (IPs) within the EU and sets out our assessment of their impact.

We define incremental capacity as the provision of additional capacity through investment in pipelines and/or compressors and similar equipment between Member States (MS), or entry/exit systems within an MS, that are already interconnected. New capacity is that between MS that are not already interconnected.

Our study has been informed by many helpful discussions with members of the Steering Group from ACER, the National Regulatory Authorities (NRAs) and the European National Transmission System Operators for Gas (ENTSOG) and by data for the case studies of illustrative projects contributed by individual TSOs and NRAs.

Context

A number of features of the gas industry and its regulatory framework provide the context for the study.

The growth in European gas demand has slowed and some projections suggest that demand will peak in the next 10- 20 years. At the same time, national production has declined and efforts have been made to increase and diversify imports through construction of LNG regasification terminals and new pipelines to traditional and new suppliers. The development of gas wholesale markets, the shortening of the contract terms on which gas is purchased and a greater emphasis on security of supply have all made gas flows less predictable. This has driven a need for greater flexibility provided margins of unused transmission capacity and by gas storage.

These trends have also led to a stronger emphasis on scenario planning as exemplified by ENTSOG's biennial EU Ten Year Network Development Plan (TYNDP) which builds on national and regional TYNDPs. The next EU TYNDP is due to be produced in draft in early 2013.

With Transmission System Operators (TSOs) now independent from gas shippers, more information for planning purposes now comes from consultations and Open Season (OS) processes. The latter also serve to confirm shippers' appetite to make binding commitments to purchase capacity. In many cases decisions to invest are made contingent on the results of an open season, an arrangement known as a market test. This has been called market-based investment.

A number of such OS processes have now been run. In 2007 guidelines on good practice were produced by the Council of European Energy Regulators (CEER), although these were not always followed. While OS are very flexible, they require considerable effort on the part of TSOs and shippers for design, implementation and participation.

As part of the third energy package, ACER and ENTSOG have now embarked on the development of network codes (NC) including the NC on capacity allocation mechanisms (CAM). This is currently at the comitology stage and is expected to come into force in autumn 2013 and is likely to be implemented during 2015. The scope of the work on NC CAM was deliberately restricted to *existing* capacity in order to speed the development process, but it was always recognised that *incremental* capacity needed to be addressed in a compatible manner.

In 2012 the CEER ran a consultation on options for dealing with market-based incremental capacity investment and received many responses from TSOs and shippers. The use of integrated auctions, offering both existing capacity and incremental capacity, and open seasons were both considered positively in the response to the consultation. Only one MS, Great Britain, has experience of using integrated auctions in this manner and these were applied to entry capacity to the national hub, not to cross-border capacity. Respondents to the consultation placed considerable emphasis on the regularity of offers of incremental capacity and many stressed the need for an EU-wide approach.

Problem definition and baseline

In the context described above, the problem to be addressed is how to ensure economically efficient investment in incremental capacity is made in a timely fashion at all IPs and that the risks are equitably shared between shippers, consumers and investors.

The solution needs to recognise the considerable diversity that exists in the economic regulation of gas transmission capacity among MSs. There are important differences in the incentive structure as well as in regulatory parameters such as permitted returns on investment and depreciation periods.

As noted above, experience with OS processes has been mixed. Where a market test has been incorporated, a wide range of different forms have been adopted and the results have sometimes been unexpected. TSO cooperation has proved to be a challenge in a few cases.

The experience of integrated auctions in Great Britain is based on a design that was tailored to suit National Grid's tariff methodology and Ofgem's strong emphasis on incentive regulation. It worked well for a many years but is now under review following a change in the rules for planning approvals which will lengthen investment lead times. Discussion with a number of NRAs suggests that the methodology used by National Grid is unlikely to be acceptable in continental Europe.

The focus of this study is to what extent the problem of incremental capacity should be addressed by an initiative to harmonise the arrangements at EU level. The baseline against which any harmonisation initiative needs to be assessed is no action at EU level. This baseline would imply:

- no change to the existing NC CAM, making it impossible to hold integrated auctions in which investment was contingent on the results of a market test[1];
- there would be no obligations on TSOs to cooperate in order to identify incremental capacity projects and/or to offer such capacity at regular intervals;
- OS processes would be the only way to assess if the shippers' appetite to buy incremental capacity was sufficient to make the case for investment. These would not be carried out within any EU framework; and
- offers of incremental capacity would have to be made separately to sale of existing unsold capacity, even though this distinction has no meaning for shippers.

The result is likely to be delays in providing incremental capacity and deferral of associated economic benefits.

Objectives and assessment criteria

The objectives of EU intervention would be to develop the internal energy market, to contribute to security of supply and to support gas supply to consumers at fair prices.

Consistent with these objectives we have used the following criteria in our qualitative assessment of the options:

- promotion of timely and efficient investment decisions;
- reduction in the risk of capacity becoming stranded in the longer term;
- avoidance of cross-subsidies and discrimination;
- transparency of the option with respect to stakeholders;
- proportionality in terms of EU doing no more than is necessary;

1 It would still be possible to offer such capacity under the NC CAM if the investment decision was made in advance so the capacity was not offered in the auction on a conditional basis.

- minimising the administrative burden on TSOs, shippers and NRAs; and
- ease of implementation given existing practices within MS.

We have also briefly considered possible social and environmental impacts.

Design of the market test

Before deciding to invest in incremental capacity at IPs, many TSOs and NRAs have, as noted above, required shippers to make binding commitments to purchase capacity as part of a market test. This process provides evidence that the investment is indeed required and reduces the risks for consumers or TSO shareholders who might otherwise carry the risk. The allocation of residual investment risk among these parties depends on the characteristics of the regulatory regime and the TSO's ability to socialise costs and recover them from the national market for gas. The latter is also sensitive to the size of the investment risk relative to the size of the national market.

Depending on the market circumstances, shippers are only willing to make commitments to buy incremental capacity for between 5 and 15 years from the commissioning date. We refer to this as the commitment horizon. Given that incremental capacity may not enter service for 4-5 years, this implies a willingness to buy capacity for use up to 20 years in the future. The commitment horizon is nevertheless short compared to the depreciation period used in most MSs as the basis for TSO revenues and thus the pricing of capacity. In consequence, even where there is strong demand over the shipper commitment horizon of 5 – 15 years, a significant residual risk is likely to remain with consumers and TSO shareholders.

The aim of our work on the market test has been to illustrate the impact of the different parameters, consider what principles should guide the design of the market test and to assess whether it would be possible to define an EU –wide harmonised threshold range that could be used to trigger investment.

As the examples we have considered indicate, market tests have often been conceived in terms of thresholds based on quantity – a proportion of the capacity being sold for a number of years. For a number of reasons, we think that a better approach is to use a financially-based market test which compares discounted revenues to the value of the investment. In particular, this allows the price of capacity and the higher value of earlier cash flows to be taken into account. A test in this form also has the same form as a conventional financial appraisal. However, given the shipper commitment horizon relative to the normal asset life, a cost coverage ratio (discounted revenues divided by investment costs) of under one is to be expected. The expectation is that the balance of revenues to recover the cost of the investment will be generated from capacity sales during the life of the asset.

We have illustrated the impact on cost coverage ratios of:

- discount rate
- shipper commitment horizon
- percentage of capacity retained for short-term allocation; and
- life of the assets.

Many projects also have external benefits, such as security of supply, which shippers may be unwilling to pay for directly. We suggest that these benefits are estimated separately and taken into account as notional "revenue" in the market test. A proportion of the costs representing these benefits would be socialised.

Where bundled capacity is offered, investment may be undertaken by the TSOs on both sides of the IP. Each TSO might wish to have a separate market test using its own parameters. We think that a single market test is to be strongly preferred to two separate tests. This could be a combined test for the whole investment of both TSOs or a test performed by one TSO which the other will accept as the basis for its investment decision. A single test is more likely to be transparent and encourage shipper participation in the process. However, we recognise that there may be occasions when two tests cannot be avoided.

Other principles which we think should apply to market tests include:

- details of the market test need to be transparent and capable of being replicated by shippers in order to generate confidence;
- the threshold cost coverage ratio needs to be chosen on the basis of a realistic view of the time horizon over which shippers are willing to make binding commitments in the relevant markets;
- market tests should be applied sequentially, starting from the first level of incremental capacity in order to determine the optimum size of the investment;
- unless the allocation process uses a fixed nominal tariff, it will usually be better to frame the test in real terms excluding inflation; and
- the economic life of the asset needs to be carefully considered and reflected in pricing and in the threshold cost coverage ratio.

We think that decisions on the cost coverage ratio in the market test need to be made at national level in the context of the relevant regulatory regime(s) and an understanding of shippers' appetite to make long-term commitments. Given the wide range of variables and attitudes to risk, we do not think that it would be appropriate to define an EU-wide harmonised threshold range at which investment to provide incremental capacity must be carried out, even in the context of the principles we have outlined.

Description of the options

We first consider enabling activities and then sets of options with regard to different aspects of harmonisation namely:

- when incremental capacity should be offered; and
- the form of such offers of incremental capacity.

Unless certain conditions are met which indicate that there is unlikely to be any demand for incremental capacity (see below), we propose that TSOs should be under an obligation to cooperate in order to identify projects to provide one or more levels of incremental capacity at each IP. This would be done on a biennial basis and be integrated with the cycle of activities that lead to the biennial EU TYNDP.

With regard to issue of when incremental capacity is offered, we have considered the following options:

- **Option I - no EU action**: the timing would be left to the good judgement of TSOs and NRAs, without any EU intervention to establish a harmonised approach;
- **Option II - mandatory biennial offering unless certain conditions met**: the proposal of a biennial offering is intended to reflect the frequency of production of EU TYNDPs. This would be the default unless certain conditions were satisfied. The suggested conditions which would justify not offering incremental capacity are:
  - more than 5% of existing, yearly capacity remaining unsold for the period Y+5 to Y+8 following the last NC CAM auction of yearly capacity; or
  - less than 5% of the existing capacity remains unsold but this has only arisen because of a TSO decision to shift unwanted capacity to another IP; and
  - projected physical congestion at the IP in the in no more than one scenario of the EU TYNDP;
- **Option III - mandatory biennial offering**: this option would require capacity to be offered at least every two years at all IPs (no conditionality).

On the more complex issue of how to offer incremental capacity, the options we have considered are as follows:

- **Option A - no EU action on harmonisation**: this is the baseline option of no intervention at EU level;

- **Option B – stronger emphasis on central planning**: this option places more emphasis on the planning process to assess the benefit of incremental capacity at IPs but, like Option A, does not otherwise seek to harmonise how incremental capacity is offered;
- **Option C – integrated auctions**: this option would enable integrated auctions of existing and incremental capacity by modification of the NC CAM. There are two variants of this option; and
- **Option D – open seasons**: this option would provide an EU framework for the conduct of OS processes. There are three variants of this option.

As noted in the discussion of the problem definition, we not think that the approach used by National Grid in Great Britain would be an acceptable basis for integrated auctions in continental Europe. The variants of this option that we have considered are therefore:

- **Option C1 – single offer with an integrated market test**: the market test is integrated into the software and the results are available in real time so that bidders can adjust their demand for annual capacity during each round of the auction if it is sensitive to the quantity of capacity released[2]; and
- **Option C2 – parallel offers with separate market test**: for each year beyond the investment horizon, yearly capacity would be offered separately for each potential supply of capacity (e.g. unsold existing capacity only, unsold existing plus incremental level 1 and unsold existing plus incremental level 2). Bidders would express their demand for the products at each capacity level in each round. The market test would be done after closure of the auction to see whether to release any incremental capacity. Capacity allocation would reflect the aggregate demand and the clearing price for the level of capacity released, with the other results being discarded.

If NRAs want it, it would be possible for the reserve price for the offers of incremental capacity to vary from the floating tariff paid by existing capacity holders. This would be done by starting the auction at a minimum premium. In this case the premium would reflect the higher unit costs of the incremental capacity.

With regard to OS, we have identified a number of essential elements of the binding phase that would be the basis for harmonisation of the principles to be

2 Please note that this option is put forward as a concept. Considerably more work would be needed to confirm that this concept would form the basis of a stable convergent process.

adopted, whilst leaving considerable flexibility for TSOs and NRAs to address specific circumstances at each IP. This would formalise and develop many aspects of CEER's GGPOS. In particular, we propose that open seasons require bidders to express demand for capacity at a number of different price steps so that this data can be used in the market test and, if there is excess demand, in the allocation process.

The main attraction of an open season is that it offers flexibility to consider ways in which incremental capacity at different IPs might interact and to have shippers express their willingness to pay for different options in ways that could not be made compatible with the NC CAM rules. For example, it would be possible to link bids for capacity at more than one IP, as was done in the FR-ES 2015 OS described in Annexe 3.

The variants of the form of open season that we have considered are:

- **Option D1 – offer of incremental capacity only**: the open season would be run as a separate process for determining whether to invest in incremental capacity and, if the market test was passed, would allocate the incremental capacity based on the binding requests for capacity received. The reserve price would be specific to the incremental capacity. The long-term NC CAM auction for existing, unsold capacity would continue under the existing NC CAM rules;
- **Option D2 – combined offer of incremental and existing, unsold capacity**: as for Option D1 except that the open season would offer incremental capacity together with any existing unsold capacity – reflecting the fact that shippers are interested in the capacity product and not whether it already exists or is considered to be incremental. The reserve price could be common to both unsold existing and incremental capacity. If the market test was satisfied, both existing and incremental capacity would be allocated and the subsequent NC CAM auction of yearly capacity would be cancelled; and
- **Option D3 – combined offer of incremental and existing, unsold capacity with allocation under the NC CAM**: the capacity offered would be the same as in Option D2 but shipper commitments or bids in the open season would only be used for the purpose of the market test, not for capacity allocation. All bids received would remain binding after the OS and be entered into the subsequent NC CAM auction which would serve to determine the final allocation of capacity. Shippers would be able to increase (but not reduce) their bids for capacity in the NC CAM auction. , Shippers that had not participated in the open season process would also be able to bid. The clearing price would be the same, or higher, than that implied by the open season process. Shippers who would have been allocated capacity in the OS process,

could find they had no allocation in the NC CAM auction if the price was driven higher than that implied by the bids in the original OS process.

The primary rationale for the two step process in Option D3 would be to ensure capacity allocation always takes place using NC CAM rules. If the principles for the conduct of OS processes were part of the NC CAM, this rationale would have less force.

As in the case of integrated auctions, if NRAs want it, it would be possible for the reserve price for the offers of incremental capacity in OS processes to vary from the floating tariff paid by existing capacity holders.

Assessment of impact and comparison

We first describe our assessment of the options concerning *when* to offer incremental capacity and then our assessment of the options for *how* to offer it. We then illustrate the potential magnitude of the benefits and costs of EU intervention to harmonise the arrangements.

With regard to *when* to offer incremental capacity, we have examined the different options using the assessment criteria listed above. The preferred option that emerges is that incremental capacity should be offered biennially at each IP unless the conditions are satisfied that suggest there would be no demand for it. Option II is therefore the preferred one.

The assessment of the options for *how* to offer incremental capacity is more complex. Our assessment indicates that:

- all of the harmonisation options (Options B, C and D) are significantly better than the baseline;
- integrated auctions and open seasons are significantly better than restricting harmonisation to cost benefit analysis of incremental capacity at all IPs;
- among the integrated auction variants, parallel offers with different levels of supply (Option C2) is better than trying to integrate market test into the software (Option C1);
- among the OS options, combined offers of existing unsold and incremental capacity in a single step (Option D2) is better than the other options. In particular, we do not think that there is sufficient merit in the two step approach (Option D3) to outweigh the concerns about the complexity and perception that it would be unfair to participants in the OS process. However, feedback from the current Fluxys –TENP open season, which follows a process that resembles Option D3, will help to determine if this view is correct.

Our assessment is done as if all of the options are mutually exclusive but in practice the preferred versions of the main options (Option B, C and D) have a complementary character:

- cost-benefit analysis, without other harmonisation measures, would make only modest contribution but the results of such analysis provide a basis for design of market tests that take proper account of externalities for use in offers of incremental capacity using either integrated auctions or OS;
- where the incremental capacity project is relatively straightforward and only involves two TSOs at a single IP, integrated auctions provide an effective solution which will be transparent, imposes limited administrative burdens andeasy to implement ; and
- where incremental capacity projects are more complicated and involve more than two TSOs at a number of IPs, the flexibility of an OS process offers a greater likelihood of making efficient investment decisions.

Our conclusion is that all incremental capacity projects should be the subject of cost benefit analysis using the harmonised methodology already being developed by ENTSOG in connection with the planned Infrastructure Regulation and that TSOs should have a choice over how incremental capacity is offered, depending on the complexity of the project.

We do not have data to assess the benefits and costs of each individual option. We have therefore chosen to illustrate the magnitude of the benefits of EU intervention by looking at the impact on areas of Europe accounting for about 10% of EU gas demand and which currently have significantly higher gas prices than the average. We think that harmonisation is most likely to enable incremental capacity projects to be executed *earlier* than would otherwise be the case, rather than to result in projects which would not otherwise have been undertaken. We have therefore considered the annual benefits and costs that might arise from bringing forward investment in incremental capacity by one year.

The main assumptions we have used are:

- a range of capacity costs in terms of €/GWh/day/km taken from Great Britain and a planned HU-SK interconnector project which was accepted for EEPR support;;
- incremental capacity sufficient to bring new gas supplies equal to 5% of the assumed demand of 500 TWh over an assumed average distance of 500 kms; and

- benefits for all consumers based on a €1/MWh reduction in wholesale prices in the destination market areas due to the shift in the supply curve as well as benefits for shippers on the gas flows of €4/MWh due to the price differential that remains.

We have also assumed a small net saving equal to 0.5% of annual transmission investment in the non-FID category due to the elimination of investment projects which would otherwise have become stranded. This benefit flows from the cost benefit analysis and use of the economic life as the basis cost recovery.

The calculations based on these illustrative assumptions indicate an annual benefit of over of about €650million and a maximum annualised investment cost estimate of €27 million, a ratio of over 20. Additional benefits would also be available in other areas of the EU.

We have also looked at the cost of implementing the new measures, again on the basis that costs for project identification and feasibility assessment are brought forward as a result of harmonisation rather than being additional. We estimate an annual cost of about €7 million.

Implications for framework guidelines and codes

We have considered the impact on tariff harmonisation and on the comitology version of the NC CAM.

With regard to the framework guidelines, the changes that need to be made for incremental capacity require considerable further debate and then coordinated modification of a number of network codes. We therefore provide a view on the implications for tariff harmonisation and then consider what points could be introduced in the Framework Guidelines at this stage.

With regard to the tariffs, we see the main area for harmonisation as:

- the principles for design of the market test. Details of the test would continue to be defined at national level by the relevant TSOs and NRAs;
- assessment of the economic life of the asset and for regulatory depreciation to be based on the economic life and/or the profile of the economic value over time in order to align the depreciation charge to projected WTP;
- enable NRAs that wish to do so to start auctions of incremental capacity at a premium over reference prices in the event that TSOs have a floating tariff and NRAs wish to protect current holders of existing capacity, if the unit cost of incremental capacity is higher; and
- with respect to the price payable to:

- provide that the price payable for yearly capacity allocated in an earlier auction for a given year will be capped at the price payable in any subsequent release of incremental capacity for the same year;
- clarify that premia can arise in offers of incremental capacity using integrated auctions or using OS processes; and
- enable TSOs to index any premia over the reserve price in order to maintain the value in real terms. This would only be possible if it was stated in the capacity contract - we do not propose a retrospective change.

With regard to the existing framework guidelines, we propose at this stage only minimal changes to require market tests to be transparent and to provide greater flexibility with regard to the definition of the price payable.

With regard to NC CAM, we think the main changes are:

- TSO co-operation to identify incremental capacity projects for all IPs unless conditions are met that indicate shippers would not be interested;
- obligations to offer incremental capacity biennially unless the conditions specified previously are met – either through an integrated auction or an OS process, depend on the number of TSOs involved;
- amendment to regulations concerning yearly capacity auctions to permit yearly capacity to be offered for different quantities of existing and incremental capacity and to permit any existing unsold yearly capacity to be offered in an OS process for incremental capacity, where this basis for offering incremental capacity is justified by the number of TSO involved;
- minor amendments to the ascending clock methodology to make it compatible with the offers of incremental capacity; and
- amendments to the provisions on tariffs in line with the comments above on the framework guidelines.

Further details are given in the main body of the report.

We do not think that any changes are needed to the CMP decision.

Key design elements and roadmap

Drawing together the different elements set out above, the package of measure we suggest as the basis for harmonisation is as follows:

- **market test**: we propose a set of principles to govern market tests used in demand-based investment. However, we do not think, given the wide range of circumstances, that it would make sense to define harmonised threshold ranges within which a positive result would trigger investment;

- **identification of incremental capacity options at IPs**: an obligation on TSOs to cooperate to identify options for incremental capacity at all IPs unless the specified conditions suggest that there is unlikely to be demand for such capacity. Linked to the principles for the market test, we also suggest that TSOs should apply the cost-benefit methodology being developed in the context of the draft Infrastructure Regulation to incremental capacity projects that are not accorded PCI status;

- **when to offer incremental capacity**: we propose that, unless conditions are met that mean that there is unlikely to be significant demand for incremental capacity, TSO should be required to offer such capacity on biennial basis at all IPs although the decision to invest could depend on the results of a market test. The first year in which capacity would be offered would correspond to the end of the investment lead time;

- **how to offer incremental capacity**: incremental capacity for which the investment decision was subject to a market test would be offered using one of the following two methods:

  - **an integrated auction**, conforming to Option C2, in which yearly capacity is offered separately with different levels of supply (existing + incremental capacity) in order to provide reliable information on the demand at different price steps using the ascending clock methodology. A market test applied after the auction would determine if any incremental capacity would be released and thus which set of auction results for capacity allocation would be applicable. This method would be used where no more than two TSOs were directly involved in the offer and the complexity of the offering was compatible with current NC CAM auction rules (no linking of bids at different IPs); or

  - **an OS process**, conforming to Option D2, based on harmonised principles for conduct of an OS that would be binding on TSOs. This would be used for more complex projects where the number of project options and/or TSOs involved called for the flexibility available from an open season process. The market test included in the OS process would also conform to standard principles so that shippers would be asked to express their demand at a number of price steps.

- **tariff harmonisation**: in addition to a number of adjustments to implement the arrangements above we suggest

- a new rule that caps the price payable for capacity for a given year by existing capacity holders by the price set in a subsequent offer of incremental capacity for the same year; and
- addition of a principle that pricing should be based on an assessment of the economic life of the asset and/or the profile over time of its economic value in order to reduce the risk of asset stranding.

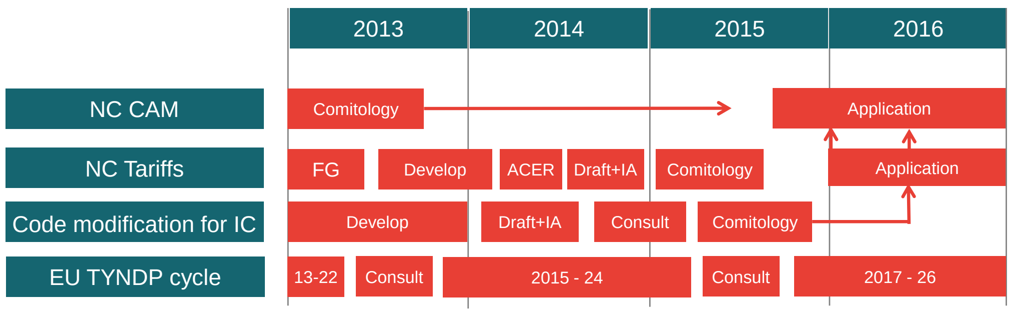
Following a process of debate, we think that the majority of the harmonisation measures would be implemented through a coordinated code modification request concerning the NC CAM and the planned code on tariff harmonisation made by CEER to ACER. Given the time required for further development of these proposals, we think that this route is more practical than any attempt to make significant changes during the final stages of adoption of the NC CAM or in the post consultation version of the Tariff Framework Guidelines.

Based on our understanding of the time required for the different stages for development and adoption of these regulations, harmonised arrangements for incremental capacity might become applicable during the course of 2016.

In terms of incremental capacity projects, the EU TYNDP for 2015-24, the third formal version of this document, would have already been published, providing a good basis for determining at which IPs incremental capacity should be offered.

Figure 1 below illustrates this tentative roadmap.

Figure 1. Tentative road map for implementation of incremental capacity measures



Source: Frontier

Applicability to new capacity

Finally, we have considered the extent to which our proposals could be applied to new capacity as well as to incremental capacity.

Our conclusions are as follows:

- **principles concerning design of market tests**: these principles can be applied directly to any offer of new capacity;
- **when to offer capacity**: our proposals are not directly applicable to new capacity because there is no data to assess the conditions. The case for new capacity between MS that are not currently connected needs to be kept under review in the GRI TYNDPs; and
- **how to offer capacity**: integrated auctions are not applicable because there is no existing capacity to be offered but an ad hoc auction could be used with the same methodology as that in the NC CAM and held on the same platform. Open season provide another option for offering new capacity when there are more than two TSOs concerned.

Once new capacity has been built, it will become an existing IP and the normal NC CAM and CMP rules will apply.

1 Introduction

Frontier Economics has been appointed by ACER to carry out a study concerning the impact of policy options for taking investment decisions on the provision of Incremental Capacity at gas Interconnection Points (IPs) within the EU.

This Final Report has been prepared following three meetings with the ACER led Steering Group for the study. The study has also been informed by many helpful bilateral discussions with members of the Steering Group from ACER and the National Regulatory Authorities (NRAs) and by data from the case studies of illustrative projects contributed by TSOs and NRAs.

1.1 Purpose of the study

The purpose of the study is to assist the Agency in preparing an impact assessment on the use of harmonised rules on Incremental Capacity. It consider the potential implications for the Framework Guidelines on Harmonised Transmission Tariff Structures and the Network Code on the Capacity Allocation Mechanisms (NC CAM) for existing and committed capacity.

At the kick-off meeting the Steering Group stressed that it wished considerable effort to be devoted to the development and design of options rather than attempting to look at their impact in great detail. We have taken account of this guidance in our approach.

1.2 Scope of harmonisation proposals

We understand that the scope of any harmonisation proposals will be on incremental capacity between adjacent entry/exist systems within the EU in so far as these subject to booking procedures by network users. This is the same scope as the NC CAM.

Use of the term "Incremental Capacity" implies that there is existing capacity to be expanded. On the basis of the current draft of the NC CAM, all unsold capacity between areas adjacent entry/exit systems will be allocated as a single Virtual Interconnection Point (VIP)[3]. Given this definition, Incremental Capacity could refer to a new physical pipeline between two entry/exit systems that were already connected in the sense that this would add to the capacity of the VIP.

3 This requirement is subject to certain condition laid down in Article 19.9 of the NC CAM.

In the ENTSOG 2011-20 Ten Year Network Development Plan (TYNDP), there are 54 such IPs/VIPs listed in the existing and final investment decision (FID) category, counting both flow directions and each VIP as one IP.

The term Incremental Capacity cannot sensibly be applied to capacity between two entry/exit systems that are not currently connected - there will be no existing capacity to allocate through the NC CAM. This must be considered as new capacity. While the focus of the study is not such new capacity, some of the options considered may be appropriate to help reach decisions about investment in new capacity. We consider this point in our report. The ENTSOG 2011-20 TYNDP lists 19 such new IPs under the non-FID category.

1.3 Structure of the report

Following this introduction, our report is structured as follows:

- Section 2 describes the context for the study and explains the linkages with different elements of the third package and other policy initiatives;
- Section 3 provides our understanding of the problems that harmonisation is intended to address and outlines the baseline scenario against which the options can be assessed;
- Section 4 explains our understanding of the objectives and sets out the criteria that we have used for the assessment of the options;
- Section 5 discusses the design of the market test, a test that is needed however market-based investment is carried out;;
- Section 6 describes the options that we have considered for offering incremental capacity;
- Section 7 presents our assessment of the impact of the different options and an overall comparison;
- Section 8 sets out our views on the implications for tariffs, including the draft Framework Guidelines, and the CAM and CMP Network Codes;
- Section 9 summarises what we consider to be the key design elements for an EU approach – a summary of our main findings - and gives a tentative roadmap for implementation; and
- Section 10 considers the applicability of the preferred option to new capacity.

The report also includes annexes containing a glossary, a description of the approach to gas transmission pricing and integrated auctions of existing and incremental capacity in Great Britain, details of a six illustrative transmission projects in continental Europe and map showing the range of wholesale gas prices in Europe.

There is an executive summary at the front of the report.

2 Context

There are five important elements to the context for the study:

- the outlook for the development of gas demand and supply in Europe;
- the elements of the EU regulatory framework governing investment in gas infrastructure;
- the status of the development of the Network Codes;
- current arrangements to assess the need for, and to gain commitment to, new investment; and
- the recent CEER consultation on market-based investment procedures for gas infrastructure.

2.1 Outlook for development of gas demand and supply

Annual gas consumption in 2010 in the EU 27 was 5500 TWh. Views on the outlook to 2020 diverge to some extent depending on perceptions of success with respect to the EU 20-20-20 targets. ENTSOG and Eurogas expect some growth while the PRIMES study prepared for the 2050 Energy Roadmap forecasts a decline in the reference case by 2020 and flat demand in the baseline. Beyond 2020 the PRIMES reference case indicates a further decline in gas consumption.

The outlook for demand is unlikely to be uniform over the EU as a whole.

There is a general recognition that gas-fired electricity generation will provide an important back-up role to the growing park of intermittent renewable energy installations. This implies that gas transmission capacity, like the gas-fired power plants, may have a lower load factor in future. Demand for transmission capacity may therefore remain strong and could increase even if annual gas consumption declines. However, the outlook for gas consumption suggests that the risk of stranded transmission capacity may be greater in future than it was in the past.

On the supply side, there are a number of important trends which will have an impact on the need for transmission capacity:

- continuation of the decline in national gas production, notably in GB and the Netherlands;
- increased penetration of LNG in the countries of Western Europe that border the Atlantic/North Sea and the Mediterranean, driven by new sources of supply and the desire to diversify gas procurement – in 2010

LNG accounted for some 15% of supply potential but is projected to account for about 23% in 2020[4];

- existing or planned new pipelines in the North and South of Europe to bring gas from Russia and from the Caspian/Caucuses area;
- development of reverse flow capabilities to improve security of supply on some pipelines that were hitherto only capable of forward flow; and
- an increase in the volume of gas traded on an OTC basis at European hubs and on energy exchanges, driven by greater awareness of price differentials between hubs and a wider range of supply options - although such trading does not have any direct impact on physical gas flows or demand for capacity it can have an indirect effect

These trends suggest that gas flows are likely to become less predictable in comparison to the past. Security of supply has become a more important consideration following supply disruptions in the last decade. With TSOs now independent of both production and sale of gas, they need to work with all shippers in new ways to allocate existing capacity efficiently and, where there is an economic case, ensure the incremental transmission capacity is built.

2.2 EU regulatory framework for investment in gas transmission

Article 13.2 of the Gas Directive says that:

> "Each transmission system operator shall build sufficient cross-border capacity to integrate European transmission infrastructure accommodating all economically reasonable and technically feasible demands for capacity and taking into account security of gas supply."

The results are monitored by the Commission and ACER through the requirements in the Gas Regulation for the preparation of TYNDPs. These are:

- a requirement for TSOs to establish regional cooperation initiatives and to publish regional TYNDPs every two years. There are currently six such Gas Regional Investment Plans (GRIPs) envisaged:
  - GRIP South (PT-ES-FR, co-ordinator: Enagas);
  - GRIP North-West (IE-UK-FR-BE-NL-LU-DE-DK, co-ordinator: Fluxys);

4 ENTSOG 2011 – 2020 TYNDP

  - GRIP Baltic Energy Market Interconnection Project (BEMIP) (SE-DK-PL-LT-LV-EE-FI, co-ordinator: Gaz-System);
  - GRIP North South (CEE) (PL-CZ-DE-AT-SK-HU-BG-RO-HR, co-ordinator: NET4GAS);
  - GRIP South-North (DE-FR-CH-IT, co-ordinator: SRG); and
  - GRIP Southern Corridor (IT-AT-SK-SI-HU-RO-BG-GR, co-ordinator: DESFA);

  of these plans, four have been published for the period 2012-21 and two for 2011-20[5]; and

- a requirement for ENTSOG to prepare a non-binding EU TYNDP every two years – the most recent version of this document is the 2011-20 TYNDP and the next version (2013-22) is due to be produced in the first quarter of 2013.

Moreover, for TSOs certified in the form of Independent Transmission Operators (ITOs)[6], there are additional obligations in Article 22 of the Gas Directive. Each such ITO/TSOs must submit a TYNDP annually and NRAs must monitor its execution. The NRA is required to consult with all actual or potential system users and to examine the plan to see whether it covers all investment needs identified in the consultation process and consider if the plans are consistent with the non-binding EU TYNDP prepared by ENTSOG (see above). In the event projects in the first three years of the plan are not executed, NRAs have powers to intervene to ensure the project is carried out.

TSOs not constituted as ITOs may also be required by national legislation to prepare TYNDPs, as is the case in Great Britain for example.

In addition to regulated TSO investments, Art 36 of the Gas Directive makes it possible for any group of sponsors to request exemption from the main regulatory conditions of the Directive for new gas infrastructure meeting certain conditions. The BBL pipeline between GB and NL was built on this basis (for the original forward flow capacity from NL to GB). Some major new projects, such as Nabucco, have already been granted exemption[7] and are expected to use a commercial model in which the shareholders and, potentially other parties sign long-term capacity offtake agreements to underpin financing.

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5 http://www.gie.eu/memberarea/purtext_entsog_GRIP.asp?wa=plus_GRIP&jaar=2012 North West and South published in 2011 and the others in 2012.

6 In December 2012, 15 gas TSO had been certified in this form as opposes to as Ownership Unbundled, ISOs or exempt.

7 Our understanding is that the exemption in the case of Nabucco is for the 50% of the capacity reserved for shareholders.

While TYNDPs must be published and subject to comments by stakeholders, most notably shippers, the regulatory framework does not address the issue of whether shippers need to make binding subscriptions for capacity before an investment is undertaken. This is critical for the allocation of investment risk between shippers, TSO shareholders and gas consumers.

A final element of the regulatory framework for investment is the proposed Infrastructure Regulation[8]. When this is formalised it will:

- establish arrangements to define projects of common interest, including investment to implement priority gas corridors, gas storage, LNG/CNG terminals and reverse flow infrastructure amounting to some €70 billion;
- contain provisions to facilitate the timely implementation of such projects by streamlining permit granting procedures;
- provides rules for cross-border allocation of costs among beneficiaries and risk-related incentives; and
- determine eligibility for Union financial assistance under the Connecting Europe Facility.

Our current understanding from informal communications with the Commission is that cost reallocation would only be used when there was insufficient user commitment for investments to proceed but evidence that external benefits (security of supply or potential improvements in competition) made the project worthwhile. Cost reallocation could be implemented by the TSO in the net beneficiary area paying the capacity charges for unsold capacity on a long-term basis or by including a part of the investment cost in its RAB and transferring the corresponding revenue to the TSO bearing proportionately higher costs.

It is worth noting that such inter TSO arrangements are likely to be longer term in character than commitments from network users and therefore less risky for the TSO with an excess of costs over benefits.

2.3 Status of development of the Network Codes

The issue of incremental capacity is closely related to three different network codes (NC) – those dealing with capacity allocation, congestion management and tariffs.

8 We understand that the Council and the EP reached informal agreement on the text of the regulation at the end of November 2012. http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/trans/133926.pdf

The NC on the Capacity Allocation Mechanism (CAM) deals with the allocation of unsold existing and committed[9] capacity at IPs (and any additional capacity that TSOs may choose to make available under the CMP decision). Although the relationship between decisions on uncommitted incremental capacity and allocation of existing, unsold capacity has always been recognised, the decision was taken to limit the scope of the NC CAM to existing capacity. The reason is that it was considered that the complexity of trying to develop an NC that covered existing capacity allocation and decisions on incremental capacity would delay the preparation process.

The NC CAM has now been prepared by ENTSOG, reviewed by ACER and the first comitology meeting is scheduled for January 2013. It is not expected to be formally adopted until Q2 or Q3 of 2013. On the basis of the current draft, TSOs will have 18 months after the regulation enters into force before it becomes applicable. A new platform, PRISMA, is currently being implemented with the support of 19 TSOs based on that originally operated by Trac-X in Germany.

An important feature of the NC CAM is the standardisation of the capacity products to be offered and of the timing of the auctions of these products at all IPs/VIPs across Europe.

The NC CAM also requires that, where possible, any available firm capacity at an IP is offered as bundled capacity to transport gas between the two hubs and not as unbundled capacity to transport gas to a flange at the border, the basis used for many capacity products in the past.

The NC on Congestion Management Procedures (CMP) was implemented as an EC Decision which was adopted on August 2012 and amends the existing guidelines in the Gas Regulation. The CMP provides for day ahead and long-term Use It Or Lose It (UIOLI) mechanisms[10]. There is also a requirement on Member States to put in place incentives arrangements to permit oversubscription and buy-back, thus enabling TSOs to offer additional firm capacity at IPs.

The Network Code on harmonised tariff structures is at a much earlier stage, with ACER still reviewing responses to the consultation on the draft Framework Guidelines. A final version is due to be issued by 1st April 2013. The Tariff NC will then be developed by ENTSOG. We consider later in this report the

9 Committed in the sense that a final investment decision has been made to provide the capacity and it is expected to be available within the relevant time horizon for the allocation arrangements (up to an horizon of 15 years). E.g. capacity that remains unsold after having been offered in an open season for which a final investment decision has been taken

10 Long-term UIOLI in this context refers to less than 80% utilisation in the preceding summer and winter seasons of capacity with an effective contract duration of more than one year without proper justification.

implications of our proposals on incremental capacity for the draft Framework Guidelines.

2.4 Current arrangements for incremental capacity

Three mechanisms have been used to make decisions on incremental capacity at IPs:

- regulatory approval of investments without any user commitment – the principal historical approach. This approach is still used as illustrated by the decision to offer incremental capacity from Germany to Poland at Lasow;
- open season (OS) procedures, which have been applied in continental Europe since 2005 (both within TSO areas and at IPs) for significant transmission investments – the decision to invest depends on the extent of commitments from shippers to purchase capacity. This is known as a market test; and
- integrated auctions of existing and incremental capacity, as applied to all entry points in Great Britain[11] since 2002 – the only EU MS where this approach has been adopted. The bids submitted in the auctions are used in a test to determine how much capacity to release. Full details are given in Annexe 2.

OS processes are a method of assessing the extent of demand for incremental or new capacity. This may take the form of an indicative, non-binding response and/or a firm, binding commitment to subscribe for capacity if the investment proceeds.

CEER issued Guidelines of Good Practice on Open Seasons (GGPOS) in 2007 and followed up with a Monitoring Report in 2010 assessing to what extent the GGPOS had been applied and identifying areas for improvement. The report considered the conduct of 12 OS procedures in 8 different EU countries, of which two are related to LNG terminals.

The North-West GRI has also published work in 2010 on coordination of open seasons to address some of the practical problems encountered.

A key feature of both OSs and integrated auctions is some form of market test to assess whether the extent of user commitment is sufficient to trigger the investment. In principle, this test can be based on:

[11] The entry points constitute the landfall of submarine pipelines on which only two, BBL and IUK, connect with other MS. The incremental capacity offered is for entering the NG network – the arrangements do not relate to the capacity of IUK or BBL pipelines neither of which is currently subject to third party access.

- the quantity and duration of user commitments to buy the offered capacity; or
- a comparison between the projected revenue flowing from the user commitments at a specified price, discounted to the in service date for the capacity, and the investment required to execute the project.

Design of market tests of the adequacy of user commitments are addressed in Section 5.

2.5 CEER consultation on market-based investment procedures

In June 2012 the CEER issued a consultation document on market-based investment procedures. This reflected needs identified in the GGPOS and in the framework of work on the Gas Target Model. It also considers the relationship to the planned NC CAM processes.

The paper identified problems with the existing approaches and described options for consideration and how these might interact with the TYNDP arrangements. CEER has now published an evaluation of the 30 responses received[12]. We quote below the key messages as set out by CEER:

> "Most respondents to the CEER public consultation reiterated the need for pan-European principles for the identification and allocation of incremental capacity. They call for clear and transparent mechanisms to trigger incremental capacity investment, while many point to the respective advantages of both open season procedures and integrated allocation procedures for incremental capacity.
>
> For most respondents, the decision to invest should be based on the results of an market test. Such a test would be applied to binding network users' commitments to book incremental capacity and require a proportion of the investment in question to be underwritten by these commitments. A majority of respondents, however, consider that a full standardisation of market tests is not necessary, but suggest harmonising general principles. In particular, principles such as regularity and transparency of parameters, which should be published in advance of an incremental capacity procedure, are deemed important."

12 http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Gas/Tab1/C12-GWG-92-03a_EoR_incremental_final.pdf

CEER has a mandate form the Madrid forum to present a "blue print" on the identification and allocation of incremental capacity to ensure efficient investment for presentation in April 2013.

3 Problem definition

Incremental transport capacity at some IPs will be essential to realise the objectives of an integrated internal energy market, offering a secure and fairly priced supply of energy. Whilst recognising that, to a significant extent, wholesale gas prices reflect historic long-term contracts, the scale of price differences across the EU highlighted in Annexe 4 also reflects transmission constraints.

The 2011-20 EU TYNDP prepared by ENTSOG listed non-FID transmission projects identified by TSOs and other promoters with a total estimated cost of €58.5 billion. A significant proportion of this investment will relate to new entry capacity from third countries and new IPs, rather than incremental capacity at existing intra EU IPs. Nevertheless the scale of investment in incremental capacity is still likely to be very large.

There are problems and issues in reaching decisions on investment in, and allocation of, incremental capacity by any of the current arrangements referred to in Section 2. We consider in turn:

- issues arising from the regulatory framework;
- issues arising in relation to OS processes; and
- issues arising in relation to integrated auctions.

Most of the issues concerning the test of the adequacy of shipper commitment apply to both OS and to integrated auctions.

Finally, we consider how the baseline option of no EU harmonisation might be defined.

3.1 Problems related to the regulatory framework

Investment decisions at national level are made within the applicable regulatory framework of each MS. The majority of NRAs are naturally keen to limit investments to those needed to meet national requirements in order to keep tariffs as low as possible for the consumers to whom they are responsible. While national TYNDPs are prepared with stakeholder consultation, there is a moral hazard issue in making investment decisions on the basis of requests from stakeholders that do not involve any financial commitment. Without any commitment to pay for the capacity in user fees, there is a risk of capacity being built which is subsequently considered as stranded, in the sense that there is no demand for it. The cost of such capacity then has to be borne by shippers in general to be passed on to consumers or by TSO shareholders.

The issue of investment risk is particularly acute in countries with relatively small national markets that host transmission capacity used, in whole or in part, to transit gas to other MS. Investment in incremental capacity and the associated risks can potentially have a significant impact on consumer gas tariffs unless there are long term commitments from users to pay for the capacity.

If significant investment risks remain with a TSO, these may weaken its balance sheet and cause problems for financing future transmission capacity.

These considerations drive the need to have shipper commitments to pay for a proportion of incremental capacity before any investment decision is made. Shipper participation in decision-making is also likely to lead to improved selection of projects and more efficient execution in terms of the timely project completion. However, given regulatory asset lives in excess of 40 years in many countries, there are likely to be residual risks. Even where there is strong shipper interest, commitments in excess of 15 years are considered unlikely and much shorter commitment periods are quite common.

As noted in Section 2, the NC CAM requires TSOs to offer any available cross border capacity as bundled capacity where it is possible to do so. The investment required to provide incremental capacity will thus be undertaken in at least two different regulatory regimes and will require approval accordingly. Recent studies[13] have highlighted the significant differences between these regulatory regimes across the EU in terms of:

- the regulatory asset lives and thus amortisation periods used for pipelines and compressor stations;
- the level of WACC or return on equity permitted on the regulatory asset base and whether this is nominal or real;
- the methodology for allocation of allowed costs to different entry / exit points in each market area;
- whether the basis of the regime is a revenue cap or a price cap, the latter implying that the TSO is exposed to some demand risk on capacity bookings; and
- the incentives available for undertaking certain new investment projects and the allocation of risks between TSO, shippers and gas consumer.

Any test of the adequacy of user commitments and the basis on which bundled capacity is priced needs to recognise and take account of these differences.

13 KEMA/REKK Study on methodologies for gas transmission tariffs and balancing fees in Europe, 2008 and subsequent updates.

A final issue concerns the allocation of costs and benefits. The costs and benefits of attractive incremental capacity projects may be asymmetrically distributed between the two entry/exit systems concerned. Where this arises, one of the two parties may have higher costs than benefits and will not wish to undertake the project unless:

- revenues from capacity fees paid by shippers are allocated so that each TSO has a business case for the investment; or
- costs are reallocated, as envisaged in the Infrastructure Regulation referred to in Section 2, to achieve the same objective.

3.2 Problems related to OS procedures

A substantial number of OS procedures have been run in continental Europe since CEER produced its GGPOS. Annexe 3 summarises experience at a number of IPs where incremental capacity has been offered, although not all have involved OS processes.

CEER's 2010 Monitoring Report on identified a number of important issues in the application of the OS process. The main issues are as follows:

- no clear trigger or conditions to start an OS process, leaving potentially unsatisfied demand from existing and potential shippers at an IP. Some NRAs have taken the view that contractual congestion is not a sufficient basis to trigger consideration of incremental investment[14];
- the non-binding phase is perceived as unreliable because shippers have no incentive to make their statements about capacity needs realistic;
- shippers see a lack of transparency concerning the value of investment in relation to capacity on offer and the allocation of risk between the parties (impact of late delivery, project overspend etc);
- strong pressure from shippers for greater visibility concerning the derivation of tariffs and greater certainty about how they will evolve;
- transparency issues in relation to the market test of the adequacy of shipper commitment:
  - relationship between life of assets, tariffs for cost recovery and horizon over which shippers are willing to commit; and
  - nature of any allowance for externalities (security of supply and market integration);

14 Contractual congestion arises where capacity is booked but is not used. The recent CMP decision will help to address this issue.

- requests from NRAs to withhold a percentage of the incremental capacity for short-term allocation, reducing the potential longer-term shipper commitment and risks to TSO shareholders, even if the market test is adjusted to take this into account;
- unclear rules on allocation of capacity in some cases – some OS procedures give priority to longer-term demand, some to the highest price offered – this issue is closely linked to the design of the market test;
- the respective roles of NRAs and TSOs were not always clear – some NRAs have claimed that they lack explicit power to regulate OS processes;
- need for improved inter TSO co-operation with respect to:
  - the timing of offers of incremental capacity at two or more IPs that might constitute a path for gas flows; and
  - the rights to make bids conditional on acquiring capacity at more than one border or to have step out rights from commitments under certain conditions; and
- the unwillingness of TSOs to share data on demand for capacity at IPs, especially from specific shippers, for confidentiality reasons.

These points do not seem to be fundamental criticisms of the OS mechanism in itself but of the way it has been implemented, sometimes without following the CEER's GGPOS. With TSOs and NRAs having to cooperate in order to allocate existing capacity under the NC CAM, one might reasonably expect significant improvements in some of the areas above to arise in consequence.

A more fundamental issue is that network users are only interested in capacity – they do not care whether it already exists or is incremental. Their concern is availability and price. An integrated approach therefore reflects better the nature of the demand, but is also less flexible given the detailed rules developed for the NC CAM.

Furthermore, having different mechanisms for the allocation of existing and incremental capacity could lead to perverse outcomes. For example, shippers could be allocated existing capacity at a premium in the long-term NC CAM auction for, say, Y+8 if there were excess demand. Then, a year or so later, in an OS for incremental capacity, capacity for *the same gas year* could be allocated at the reserve price or at a lower premium than that which had applied previously. Such an outcome is much less likely to arise with predictable, regular offers of incremental capacity.

3.3 Problems related to integrated auctions

As noted in Section 2, National Grid in GB offers incremental capacity at all entry points on its network every year using integrated auctions.

It is important to recognise that these integrated auctions must be capable of serving two purposes:

- to allocate existing capacity at a price premium where there is excess demand and the market test for incremental capacity is *not* met; and
- to provide demand and price data that can be used as an input to the market test concerning whether to release incremental capacity and, if the test *is* met, to allocate such incremental capacity.

The first requirement means that there must be a set of increasing price increments against which users can indicate their willingness to pay for capacity in the form of the quantity bid. This is essential if capacity is to be allocated to those with the greatest willingness to pay.

For the second purpose, each of the price increments is also associated with a potential incremental quantity of capacity and the investment cost (capex) needed to deliver this capacity. If the present value of the incremental revenue from release of this capacity over an 8 year horizon is greater than 50% of the deemed project value, the incremental capacity must be made available.

Some features of GB and its regulatory framework that make this possible with limited effort are:

- the LRMC transport and tariff methodology approved by Ofgem in GB can quickly be used to derive notional investment costs for multiple levels of incremental capacity at each entry point. The methodology usually leads to cost estimates that are not linearly related to incremental capacity, with unit prices rising gradually or in steps as incremental capacity quantity increases;
- the nature of the regulatory contract in GB includes "revenue drivers" that offer additional revenue for releasing incremental capacity if the market test is met, based on the deemed investment cost. There is an incentive on National Grid to provide the capacity more cheaply. The actual investment cost of providing the capacity is added later to the regulatory asset base following an ex post efficiency assessment by Ofgem; and
- only gas flow changes on National Grid's own network are considered as a result of providing incremental capacity at entry points – the capacity offered is not bundled with capacity on another network to permit gas to be transported from hub to hub. It is entry capacity only

that is sold and there is no need to agree common arrangements with another TSO.

We will consider later the applicability of this approach to the design of integrated auctions for IP capacity in continental Europe.

The current standard lead time for releasing incremental capacity in GB is 42 month. However, changes in the national framework for planning now suggests that the lead time could increase to 72 – 87 months[15] and require considerable local consultation on options. With North Sea production in decline, requests for *new* entry capacity (e.g. for an LNG terminal) are more likely than for incremental capacity at an existing entry point. In this context, National Grid has started consultation on moving away from the current system of annual integrated auctions open to all shippers. The main options now under consideration are:

- an application process involving an agreement on advanced reservation of capacity, similar to that currently applied to long-term exit capacity to meet gas demand; or
- an integrated auction, as at present, but conducted on an ad hoc basis rather than annually and open only to those who have previously signed a bilateral agreement with National Grid.

The first option is currently the primary focus of development in the industry transmission working group.

3.4 Baseline option

The baseline or business as usual option is a statement of what would happen if there were to be no EU policy initiative to harmonise the approach for offering incremental capacity.

This does not, of course, mean that individual NRAs and TSOs would not try to improve the arrangements for offering incremental capacity but it would not be done within a common EU framework. However, there would be no obligation for TSOs to cooperate with regard to incremental capacity projects.

As already noted, the current NC CAM is focussed on existing and committed capacity[16] and does not consider the possibility of an integrated auction, with a market test for conditional release of incremental capacity.

15 http://www.nationalgrid.com/uk/Gas/Connections/CapacityandConnections/Background/

16 It also addresses additional capacity offered under the CMP arrangements i.e. not reflecting physical investment.

We have read the views expressed in working papers by ENTSOG and BNetzA that the ascending clock auction methodology, as defined in the NC CAM, could be adapted for conditional allocation of incremental capacity but this could not happen without EU intervention. It follows that use of integrated auctions of this type would be precluded under the baseline[17]. The only methods that would be available to offer incremental capacity involve:

- making a commitment to an investment in incremental capacity and then offering it in the normal NC CAM process, without any market test and separately at each IP; or
- using an OS process developed by the individual TSOs and NRAs, as has been the practice to date as illustrated by a number of the projects described in Annexe 3.

Shippers' concerns about the absence of any obligation to offer incremental capacity at IPs on a regular basis, an important message from the CEER consultation, would not be addressed. Any such offerings could be less predictable and/or delayed in relation to what shippers might feel would be desirable across the EU. The issue noted above, about shippers risking paying a premium for scarce existing capacity followed a year or so later by an unexpected offer of incremental capacity at a lower price, would remain unresolved..

As noted earlier in this section, where incremental cross-border capacity has been offered in the past with a market test, the adopted method has been the OS process[18]. Under the baseline option this approach would no doubt continue but it seems unlikely that all of the concerns addressed in the CEER Monitoring Report on the application of the GGPOS would be resolved. The CEER GGPOS would remain voluntary and without binding force.

A further important feature of the baseline option follows from the separation of the processes for allocation of existing unsold capacity under the NC CAM and incremental capacity under OS processes. While the distinction between existing and incremental capacity is important for TSOs, it is not meaningful for shippers. Their interest is in capacity to flow gas. Under the baseline, the same products for the same year would have to be offered by separate processes unless the decision to invest is made separately (e.g. by the TSOs and NRAs) from the allocation process. This would mean that the capacity could be sold at different prices and shippers would have the burden of participating in two separate processes.

17 It would still be possible to offer incremental capacity for which an investment decision has already been made under the NC CAM.

18 The integrated auction in GB only apply to entry capacity and not to capacity between GB and Belgium or the Netherlands.

In summary, the baseline option involves the NC CAM being implemented in its current form[19], no use of integrated auctions and OS procedures continuing without any overall framework or obligations on TSOs to cooperate. Investment in incremental capacity offering significant net benefits might be delayed in consequence.

19 Subject to changes made in comitology.

4 Objectives of EU intervention

EU intervention on IC follows directly on from the development of the NC CAM for existing capacity at the relevant IPs.

The objectives of intervention would be:

- to further the development of the internal energy market by providing infrastructure for which there is a willingness to pay in order to enable wider gas trading and competition in the wholesale and retail markets;
- to contribute to security of supply by providing a flexible network that is able to respond to developments in the supply of gas from different sources and to deal with contingencies in gas supply; and
- to encourage gas provision at fair prices.

We have not referred to the interconnection of states at the periphery of the EU with the central area as this is one of the aims of the Infrastructure Regulation and is more likely to require new capacity rather than incremental capacity e.g. the proposed PL-LT interconnector.

In terms of criteria to assess design options the following have been suggested:

- promotion of timely and efficient investment decisions, including integration of the EC energy market where this is economically justified;
- minimisation of the risk of capacity becoming stranded, following entry into service and in the longer term, in the sense that subscriptions are too low to recover the cost of investment;
- avoidance of cross-subsidies and discrimination;
- ;
- transparency of the option with respect to stakeholders;
- proportionality of the option in terms of EU doing no more than is necessary to achieve the objectives;
- minimising the administrative burden on TSOs, shippers and NRAs; and
- ease of implementation given existing practices within MSs..

We note that there may be some overlap between some of these criteria and this is a factor to bear in mind in design of the scoring system.

Most of these criteria are economic in character. However, in line with the impact assessment guidelines, we have also briefly considered potential social and environmental impacts in our assessment, although it is difficult to differentiate the options in these respects.

Objectives of EU intervention

5 Design of the market test

As explained in Section 2, independent TSOs are required by the Gas Directive to build sufficient cross-border transmission infrastructure to integrate European gas markets, accommodating all economically reasonable demand for capacity and taking into account security of supply. The challenge is to understand the needs of the market and to define what is economically reasonable.

In principle, what is economically reasonable could be assessed using a cost benefit analysis in which the projected cost of different levels of incremental capacity provision would be compared to the projected benefits in order to identify the most appropriate capacity to provide. In practice this is very difficult to do because the benefits are not easily quantifiable and any assessment depends on assumptions about how shippers plan to source gas and on the evolution of the demand that they serve. TSOs are not always in the best position to make these judgments. For this reason, there has been a focus on market-driven investments where TSOs ask shippers to make binding commitments to pay for capacity before an investment is undertaken. Depending on the level and or value of these commitments, a decision is taken on whether to invest – this is known as a market test.

As the illustrative projects described in Annexe 3 indicate, tests used in OS in recent years have quite often required a certain proportion of the capacity to be booked – a quantity threshold - for a minimum number of years, typically at least 10, before making a FID. This approach is relatively simple to apply as an indicator but does not give any sense of the relationship between costs and benefits in financial terms. We explain below why we think a test based on projected financial flows is generally a better basis for a market test than use of a quantity threshold. **Table 1** summarises the basis and outcome of the market test used in the five illustrative projects from Annexe 3.

Table 1. Information on market tests for illustrative projects

OS or project	Test basis	Outcome of test
FR-ES 2013	Quantity – FR only	Successful for part of capacity offered based on one physical IP
FR-ES 2015	Financial – FR only	Successful on Western corridor but not for Eastern corridor
DE - PL	N/A	All capacity allocated – no explicit test – decision taken by Polish NRA.
OGE expansion	Quantity	Oversubscription requiring prioritisation process
AT - SI	N/A	Investment in Slovenia backbone proceeding but no FID on incremental IP capacity by TSOs and NRA and no plans for an OS.

Source: Frontier

We are also aware of at least one other OS process where each of the two TSOs concerned set its own market test. The result in this case was that one TSO's test was passed but the other was not – the difference arose in large part because the quantity-based test of one TSO required commitments for 25 years. This in turn reflected reluctance on the part of the relevant NRA to accept that the asset would be part of the regulatory asset base, given the risks for national gas consumers.

A market test, in some form, is common to any option for offering incremental capacity to the market. This section therefore considers the main features of a market test before discussion of the available policy options. The intention is to identify elements of the test where harmonisation could be desirable. The details would always be left to the relevant TSOs and NRA to determine.

In this section we consider in turn:

- the logic of using a market test to determine whether IP capacity is sufficient;
- the parameters of the market test and how they interact;
- the treatment of externalities;
- TSO coordination and the market test; and
- our conclusions on what it would be desirable to harmonise.

5.1 The market test in theory and practice

The NC CAM uses willingness to pay (WTP) as the basis on which to allocate existing IP capacity. WTP can also be used as a proxy for a lower bound estimate of the benefits of a project on the basis that shippers would never be willing to pay more than the benefit that they expect to derive from the capacity[20]. It is a lower bound estimate of benefits because capacity will be sold at a regulated price and some shippers would probably be willing to pay more[21]. Another reason it is a lower bound is that there may be external benefits in terms of security of supply and competition that cannot be internalised by shippers[22] – we return to this issue later on.

The WTP needs to be backed by a commitment if it is to have meaning. For this reason, information on WTP is collected in a binding procedure where those

[20] There may be instances where WTP does not reflect an economic benefit but a transfer from consumers to producers. This might occur if new transport capacity allowed gas from an entry/exit system with national production to be sold in adjacent systems at a higher price. Parties long in gas in the source system would benefit, possibly at the expense of the local consumers.

[21] For example, if the capacity provided access to a hub with significantly higher prices.

[22] Arguable, there may be a WTP for security of supply if the full costs to consumers of supply failures are reflected in the balancing mechanism.

offering to buy capacity are required to sign a contract. WTP is therefore translated into future revenues.

5.1.1 Shippers' commitments and asset lives

In theory, subject to appropriate treatment of externalities, the market test could mean that any investment undertaken has secure revenues to cover its entire costs and a return on investment. This is indeed the way in which many merchant pipeline projects are financed. Shippers sign binding ship or pay agreements for a period of years sufficient to recover the full cost of investment and a reasonable return. In practice this usually means about 20 years.

However, the assets of regulated TSOs are typically considered to have a life of 40 – 50 years for depreciation purposes and are priced accordingly. Shippers are unwilling to make binding commitments over such a long period. Many projects may be economic even if the commitments that are available (typically for between 5 and 15 years, depending on the local market) would be insufficient o remunerate the investment fully. This fact needs to be taken into account in the market test. An implicit assumption is required as to the benefits that will accrue from the investment but are not captured by the commitments that are available. To date the most frequent assumption has been that the commitments available I the early years are indicative of the benefits that will accrue in the remainder of the life of the asset.

5.1.2 How much incremental capacity is economically reasonable

In theory investment in incremental capacity should be expanded up to a point where the marginal benefits of an extra unit of capacity are equal to the marginal costs of providing that unit. Adding further capacity is then not economically justified. It is important to note that this optimum expansion does not necessarily mean that there is no congestion at an IP. The costs of adding more capacity may exceed the costs of accepting some level of congestion.

In practice, capacity investments are usually quite "lumpy" and involve discrete changes in capacity made available by adding compression and/or a new pipeline. But the principle above still applies. The costs and benefits of different levels of incremental capacity should normally be considered sequentially starting from the first increment, in order to assess the most economically reasonable level of capacity. However, any lack of monotonicity in the cost of additional supply complicates this process.

5.2 Parameters of the market test

We now consider the main parameters of the market test and how they interact. We do this using some stylised examples of the impact on the results of changing the values of key parameters.

While many OS processes carried out in the recent past have applied a test based of the duration and quantity of bookings, we focus on the type of test which converts bookings into revenues and compares their present value with the investment cost. We think that this approach is preferable because:

- shippers then see an estimate of the tariff at which they will commit to buy capacity – we recognise that in many regulatory regimes these will be projections of a floating tariff and not a firm price;
- revenues and costs can be compared, as in a conventional financial appraisal;
- it make it easier to compare different options – it was for this reason that the architects of the FR-ES open seasons described in Annexe 3 used a financial approach in the OS 2015 having tried a quantity threshold in OS 2013 ;
- it permits the possibility of meeting the test with a price premium at a lower quantity and/or shorter period of commitment; and
- it provides a link to a price-based approach to allocation, as in the NC CAM, in the event that there is excess demand at the reserve price.

Costs for incremental capacity to be used in the market test may be calculated either as:

- the cost of a specified project or projects; or
- a generic costs derived from an assumed set of assets needed to transport gas e.g. as in National Grid's "expansion constant" expressed in £ per GWh/day/km.

The choice depends on the philosophy of the regulatory regime and the approach of the relevant NRA(s) to incentivisation.

Given a measure of the prices at which shippers can express their demand, the outcome of a financially-based market test will depend on:

- **discount rate:** with most investment taking place upfront but the revenue from shipper's bookings accumulating over the life of the assets, the discount rate will determine the present value of the revenues;
- **subscription horizon**: the horizon over which shippers are willing to book capacity relative to the assumed life of the capacity. Shippers are unlikely be willing to commit to buy more than 15 years of capacity and much less in some markets – so although a WTP for the investment beyond this horizon may exist, this will not be reflected in the revenues that are committed in advance of the investment;
- **life of the assets:** The asset life will be used to determine the depreciation used to calculate regulated revenues or prices. There is a distinction between the technical and the economic life. The economic life is the time period over which the assets are expected to have a value

that exceeds the marginal cost of keeping them in operation – this may be shorter than the technical life. A further consideration is that WTP may not have a flat profile of the economic life; and

- **percentage of short term capacity retained**: to what extent ACER or NRAs require a proportion of capacity to be retained for allocation in shorter term auctions.

We deal separately, in a later sub-section, with the issue of external benefits that are not reflected in shippers' WTP.

We now look at a stylised example to illustrate how these different factors interact. We consider an incremental capacity project with a cost of €650m and expected regulated revenues of €50m pa from shipper commitments based on an assumed cost of capital of 7.3% (but we consider a range of discount rates in the stylised calculations). We use an asset life of 40 years. We assume that WTP is evenly spread over this period and that there is no option to express demand at prices higher than the reserve price. Financial values are all expressed in real terms, without taking into account inflation – this is equivalent to having floating tariffs that are adjusted for inflation, in each year[23]. We later consider the impact of inflation in relation to discount rates and the limited horizon over which shippers are expected to make binding commitments.

5.2.1 Discount rate

A cost benefit analysis always discounts costs and benefits to a common date in order to take account of the opportunity cost of capital. For the same reason, future revenues need to be discounted for comparison with investment costs in the market test.

The discount factor should be linked to the pre-tax WACC or return on equity and cost of embedded debt used by the NRA to determine the return on the regulated asset base[24]. Whether to use a real or nominal discount rate depends on the treatment of inflation:

- real discount rates go with commitments where prices for capacity will be indexed or otherwise adjusted for inflation and are therefore expressed in real terms – the assumption used in most of our examples and the basis that will generally be appropriate where the price is floating; and

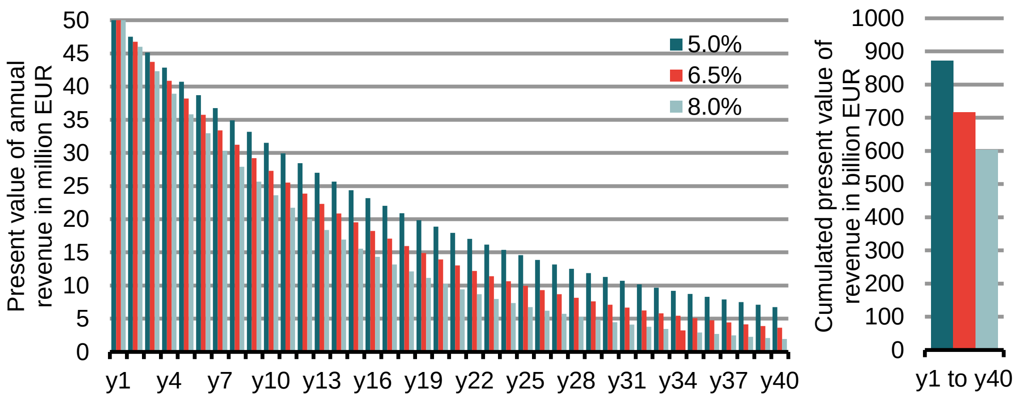
[23] The use of real discount rates and floating tariffs is for illustrative purpose. The same concept can be applied in countries that allocate capacity at a fixed nominal tariff, subject to appropriate treatment of the impact of inflation.

[24] We recognise that is some regulatory regimes, the prices be be set using a real cost of equity and a nominal cost of debt rather than a discount rate. However for the purpose of a financial market test, a choice must be made concerning whether to work in real or nominal terms.

- nominal discount rates are associated with prices for capacity that are fixed in nominal terms i.e. the price of which falls in real terms due to the impact of inflation. In countries that sell capacity at fixed nominal prices, nominal discount rates would need to be used.

Obviously, the higher the discount rate the lower the present value of future revenue to set off against the project investment costs. **Figure 2** illustrates the issue for our stylised example where the shipper commitments are (unrealistically) given for the full 40 year life assumed. After discounting, the revenues accruing in the longer term e.g. beyond Y30, make relatively little contribution to the cumulative present value shown in the bars on the extreme right. We have shown a range of discount rates to illustrate the impact.

Figure 2. Effect of discount rate on value of future revenues



Source: Frontier; assumption of €50 million annual undiscounted revenue, X-axis reflects economic lifetime of asset in years

Table 2 shows the results in terms of a coverage ratio – the ratio of the present value of revenues divided by the investment costs. At the lower discount rates the investment cost is well covered but at a discount rate of 8% the value of the revenues is lower than the assumed investment cost of €650 million.

Table 2. Impact of discount rate on coverage ratio

Discount rate	Coverage ratio
5%	134%
6.5%	110%
8%	92%

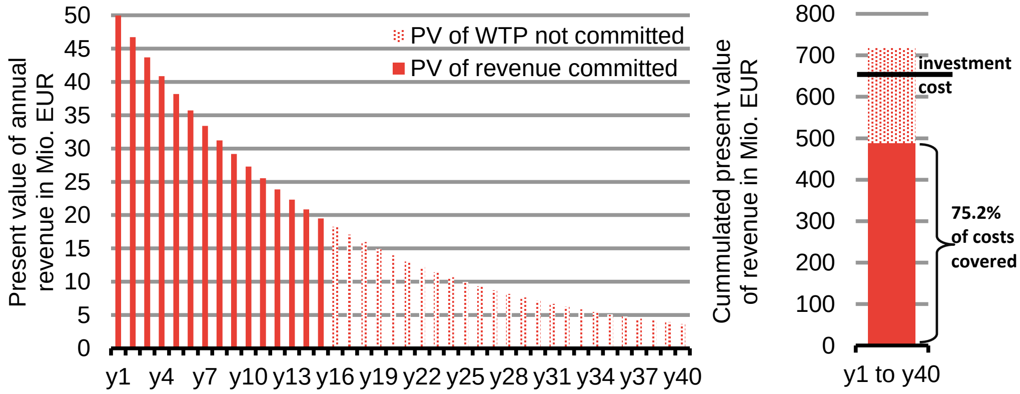
Source: Frontier

5.2.2 Subscription horizon

The example above assumed that shippers were willing to make commitments and express WTP for the full assumed life of the asset. As noted previously, the maximum subscription horizon is typically much less than 40 years. Depending on the level of uncertainty perceived by shippers, it may be as little as 5 years or as long as 15/20 years – in general the more fluid the market the shorter will be the subscription horizon. The evolution of the European gas market is quite likely to be reducing the period over which shippers are prepared to commit. It is important to remember that there will be a lead time for investment to provide incremental capacity and this lead time needs to be added to these subscription horizons. With an investment lead time of 5 years, the last year in a 15 year subscription period or horizon would be 20 years in the future.

We now illustrate the effect of different subscription horizons on the coverage ratio. We have used the same stylised example with a discount rate of 6.5% and a subscription horizon of 15 years, requiring shippers to make commitments up to 20 years in the future. As shown in **Figure 3** the coverage ratio now falls from 110% to 75.2% due to the WTP that is not committed. As before, we assume that WTP remains constant in real terms over the whole period and that shippers are not able to express demand above the reserve price.

Figure 3. Impact shipper commitment horizon on cost coverage



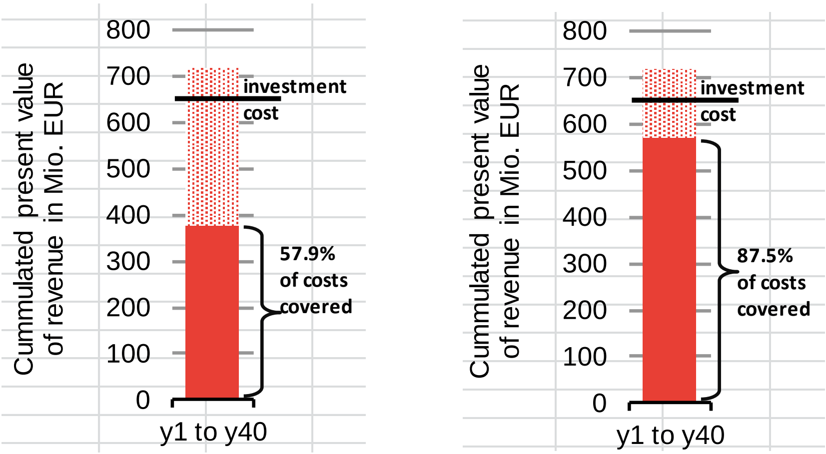
Source: Frontier; assumption of €50 million annual undiscounted revenue, 6.5 % discount rate on future revenue, 40 years economic lifetime of asset

In the above numerical example with an economic lifetime of 40 years and with revenues assumed to be constant in real term, the uncommitted revenues would be expected to accrue during the remaining economic lifetime of the asset, i.e. between year 16 and 40, for which shippers do not make subscriptions at the time of the market test.

However, just because revenue is not yet committed beyond the booking horizon of shippers, does not mean it should not be taken into account if revenue beyond that horizon can reasonably be expected. In other words, in the above example, a 75% coverage ratio would be regarded as sufficient for a decision to invest. Nevertheless, it means that there is a risk that if the expectation is wrong the asset may become stranded as far as the TSO is concerned and the costs have then to be socialised, i.e. recovered from network users in general, and thus passed on to consumers to the extent such users are meeting national demand for gas.

If the shipper commitment horizon decreases or increases, a lower or higher proportion of the costs are then covered, as shown in **Figure 4** for horizons of 10 and 20 years.

Figure 4. Cost coverage with commitment horizons of 10 yrs (left) and 20 yrs (right)



Source: Frontier; assumption of €50 million annual undiscounted revenue, 6.5 % discount rate on future revenue, 40 years economic lifetime of asset

All of the above examples use a discount rate of 6.5%. In general, the higher the discount rate, the higher the revenues over the asset life to cover investment costs and the shorter is the commitment horizon needed to produce a given target coverage ratio.

If the revenues were expressed in nominal rather than real terms (i.e. the price payable is fixed in advance and does not float in any way) then revenues need to achieve the same overall cost coverage (committed and uncommitted periods) have to rise from €50 million to €63.6 million assuming inflation of 2% pa. This also implies a discount factor of 8.63% in the place of our central case (derived as (1.02*1.065-1/100). This means that a higher proportion of revenue in real terms falls in the shipper commitment horizon and the coverage ratio rises from 75.2% to 84.1%.

A practical example is provided by National Grid's integrated auctions in GB described in Annexe 2. Revenues are expressed in nominal terms and are considered over an 8 year period after the first indication that incremental capacity is required (even if shipper commitments are available for a longer period). The discount rate used is a nominal value of 8.3%. The market test that must be met in order to release capacity is that the discounted revenues must equal at least 50% of deemed investment value.

5.2.3 Asset life

An asset should be depreciated over the period during which it will yield revenues to cover its marginal costs, even if the technical life is longer. This is known as the economic life. Given the uncertainty concerning future revenues beyond the shipper commitment horizon, one approach to managing risk is to shorten the economic life of the asset so that it approximates more closely to the commitment period. Merchant projects with exemptions under Art 36 of the

Gas Directive will normally be depreciated over a period which is very close to the duration of capacity contracts signed with shippers. .

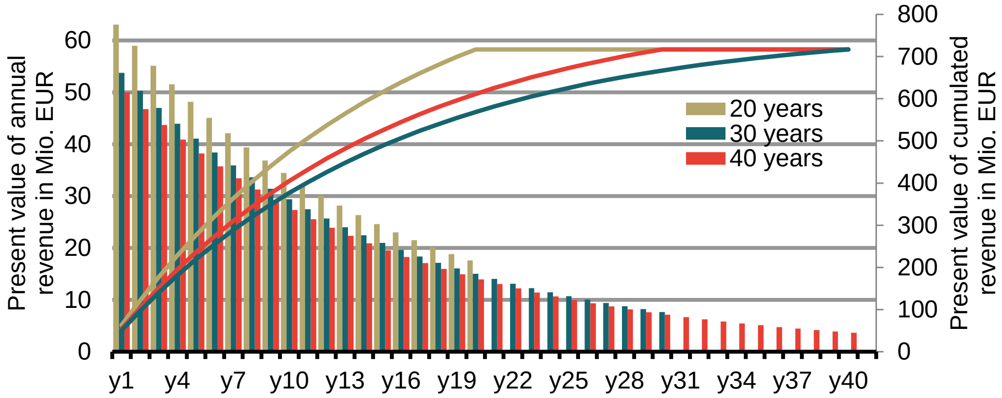
The shorter the economic life of an asset:

- the higher the coverage ratio in the market test can be; and
- the lower the risk that is borne by future network users and gas customers in relation to possible stranding of the asset.

The economic life used as the basis for deprecation determines the time period over which discounted revenue is accumulated. Given constant annual revenues, the present value of accumulated revenue at any specific discount rate is obviously lower if accumulation takes place over a shorter time period.

In our stylised example with a 6.5 % discount rate for annual real revenue of €50 million p.a. over 40 years, the accumulated present value of revenue amounted to €717million, or 110 % of the investment costs of €650million in incremental capacity. To obtain the same present value of cumulated revenue over an economic lifetime of 30 years, annual revenues would need to be greater to produce the same net benefits of the project – in this case revenues increase to €53.7 million per annum. If the economic life were only 20 years, annual revenue would need to increase to €63.1 million. The effect is shown in **Figure 5** with annual revenues on the left hand axis and the cumulative present value on the right.

Figure 5. Annual revenue requirements as asset life is changed



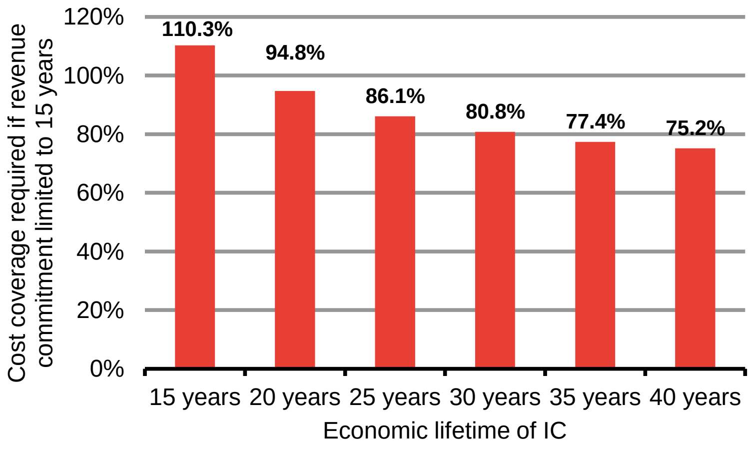
Source: Frontier; assumption of 6.5 % discount rate for future revenues

Closer alignment of the economic life and the subscription horizon of shippers, allows the cost-coverage ratio to be increased in order to trigger an investment. The potential risk to future network users is reduced. The revenue increase required from halving the asset life is 26% at the discount rate of 6.5%.

Figure 6 shows the coverage ratio achieved with full shipper commitment for 15 years as the asset life is gradually increased. When the asset life is also 15 years the coverage is 110% years but falls to 75% as the life is increased to 40 years.

Design of the market test

Figure 6. Required cost coverage ratio for different economic lives



Source: Frontier

In practical terms, depreciation is one of the cost elements that a regulated TSO can recover in allowed revenues. Changing the asset life from 40 to 20 years will double the depreciation charge but have a much more muted impact on tariffs, assuming a positive WACC[25]. An alternative approach to shortening asset life is to address the uncertainty by adopting a depreciation profile that loads more of the charge at the front end of the asset's life. In the UK, Ofgem has recently decided[26] to adopt this approach for gas distribution assets using "sum of years' digits" as the basis for depreciation[27]. The effects of using alternative profiles are shown in the text box on the following page.

A further option to address the risk of stranding, favoured by some NRAs and TSOs, is to permit a higher return on the asset value.

Finally, it is important to note that if there are concerns about stranding, it is possible to increase the price at which incremental capacity is offered at an IP without making explicit changes in the underlying depreciation rates which are, in some cases, determined by national laws. As there would be no change in permitted revenues, this would mean rebalancing charges at other entry/exit points.

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25 Halving the asset life from 40 to 20 years increases an annuity by 26% given a 7% WACC

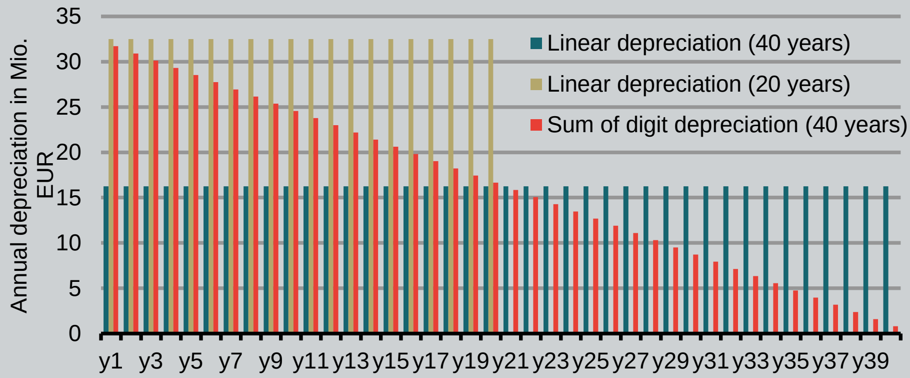
26 The decision was made in the light of the possibility that decarbonisation would mean the electrification of domestic heating and hot water. http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/GD1decision.pdf For gas transmission the depreciation period of 45 years has been maintained but will be reviewed again in the next price control period (RIIO-T2).

27 The depreciation in each year is book value times the remaining life divided by the sum of years' digits in the life of the asset. This sum is given by n*(n+1)/2 where n is the asset life.

Box: Impact of depreciation profile on risk allocation

The depreciation profile determines the allocation of risk between current and future network users during the asset life. If the asset is depreciated linearly, existing and future users are assumed to support the same share of the costs. If the asset is depreciated over a shorter time period or with a front-load depreciation method, a larger share of total depreciation is borne by shippers in the early years of the life of the asset. This protects future network users in the event that the asset is stranded but the TSO's allowed revenues are also raised in the earlier years. Depreciation charge profiles using different approaches are shown in **Figure 7**.

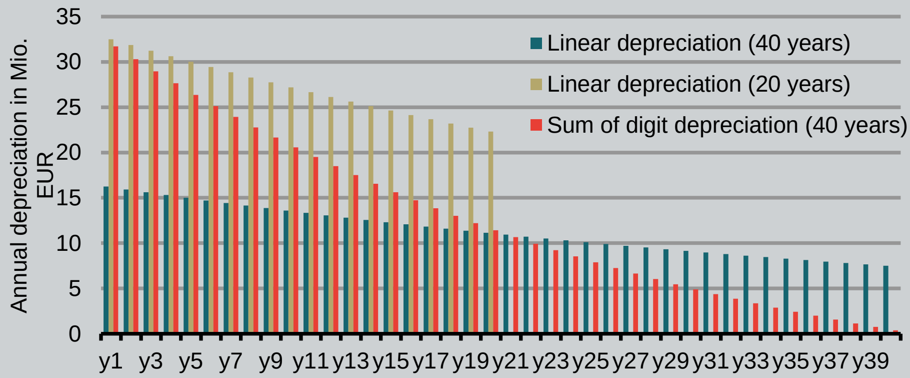
Figure 7. Depreciation profiles



Source: Frontier, assuming zero inflation, depreciation of €650m investment cost

If the depreciation charge is a nominal amount, its value in real terms falls in any case if there is inflation. This also loads a higher proportion of the real charge to the front end of the asset life as shown in **Figure 8**.

Figure 8. Depreciation profiles taking into account 2% inflation



Source: Frontier, assuming 2 % inflation, depreciation of €650m investment cost

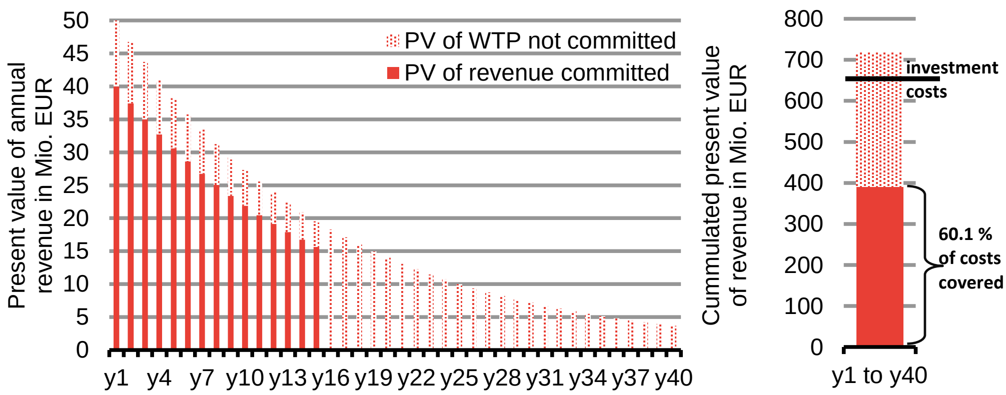
Design of the market test

5.2.4 Retention of short term capacity

ACER has proposed that any offer of incremental capacity should retain the same proportion of capacity for short to medium term allocation as in the NC CAM[28] i.e. the retained amount would not be available for shipper commitments in the offering used as the basis for the market test which concerns investment in capacity that would not normally be operational before Y5. The rationale for retention is to promote competition and make capacity available to potential new market entrants in the future. Clearly, this restricts shipper commitments from the first year and has an adverse impact on the potential coverage ratio that needs to be taken into account.

To show the impact we assume retention of the full 20% of the capacity and all other data as in **Figure 3**, including a commitment horizon of 15 years. The result is a fall in the potential coverage ratio in the market test from 75% to 60%, a reduction of exactly 20%. The commitments and missing revenue from the retention and shipper commitment horizon is shown in **Figure 9**.

Figure 9. Impact of retaining 20% for short and medium term allocation



Source: Frontier; assumption of €50 million annual undiscounted revenue, 6.5 % discount rate on future revenue, 40 years economic lifetime of asset, 15 year booking horizon of shippers

5.3 Treatment of externalities

In the examples above it was implicitly assumed that the entire benefits of an incremental capacity project would be reflected in revenues from shippers based on their WTP. But there may be three types of positive externality which are unlikely to be valued by shippers (indeed the second two may reduce shippers' WTP). These are:

[28] The NC CAM provides for 10% of capacity to be offered in the current gas year and a further 10% in the years up to the forth gas year ahead but not beyond.

- **security of supply**: in a better integrated market, gas volumes can more easily be moved from one market area to another in case of supply disruption. As some MS do have a significant exposure to a single supply source or a single supply route, this is a risk. Incremental capacity connecting another market area which has a more diversified gas supply portfolio (or major gas storage) can significantly reduce adverse consequences to consumers in an emergency situation. This might not be fully valued by shippers but might be justified in terms of social welfare;
- **improved market integration in order to lower price differentials**: incremental capacity implies that additional gas volumes can be brought from one market area into another one, potentially reducing or eliminating price differentials and making the capacity of less value to shippers; and
- **facilitating competition**: incremental capacity may allow a new supplier to enter a market in which there is little competition but the potential new entrants may be too immature to make long-term capacity commitments.

These external benefits can be incorporated into the market test in two main ways:

- assessment of the benefits and taking them into account in the market test; or
- lowering the cost coverage ratio.

5.3.1 Assessment of the benefits and taking them into account in the test

External and internal benefits are usually joint products of investment in transmission capacity and it is not possible to attribute components of the project to such external benefits[29].

The magnitude of external benefits may be indicated by a qualitative assessment using the factors shown in **Table 3**. Quantification may be challenging but can be attempted and then compared to the cost of the projects. The estimated benefits can then be considered directly in the market test, along with revenue from shippers. In the cost allocation methodology, a proportion of the costs attributed to these benefits will be socialised and recovered from all network users.

The following approaches could be used to quantify the size of these benefits:

- **security of supply**: on the basis of the the existing transmission network and sources of gas supply, an assessment can be made of the

29 An exception may arise for reverse flow projects where this capability may be separately costed and designed to increase security of supply.

probability and size of gas disruption in GWh/h, with and without incremental capacity. This quantity is then multiplied by the cost of curtailment of supply for the parts of the market impacted (typically, power generation first, then industry and finally residential consumers);

- **market integration**: an estimate needs to be made of the impact of the incremental capacity on the price differentials between the adjacent entry/exit systems during the life of the capacity. In the market in which gas prices are lowered, there will be an increase in consumer surplus which can be estimated as a benefit; and
- **facilitation of competition**: the benefit would arise from increased competition in future exerting downward pressure on prices in a market currently characterised by limited competition. As for market integration, the benefit would be an increase in consumer surplus due to lower prices but would only occur sometime after the capacity enters service.

Grants provided to projects on that basis that these represent compensation for positive external effects (e.g. grants from the European Energy Programme for Recovery[30] set up in 2009 or from the proposed Connecting Europe facility) will normally be less than any estimate of these benefits. Accordingly, such grants should not be deducted from the investment costs considered in the economic test. .

Under this approach the achievable coverage ratio for projects with and without external benefits can remain comparable in any particular market environment.

30 http://ec.europa.eu/energy/eepr/index_en.htm

Table 3. Indicators of the size of positive external effects

TYPE OF EXTERNALITY	HIGH *If true for at least one E/E area:*	LOW *If true for both E/E areas:*
Security of supply from project	• High dependence on one supply source or route different from the IP where IC is offered • Market integration with other E/E area is low • Low storage capacity • High share of customers with low short-run demand elasticity (e.g. households) • IC is relatively large compared to peak demand	• Diversified supply sources and routes • Physical integration with other E/E areas is high • Gas storages exist to compensate short-term supply disruptions • Demand is flexible and can be reduced without high costs • IC is relatively small compared with peak demand
Increased competition from project	• High concentration of supply in the wholesale market • Constraints exist between other E/E areas • Low or no integration with a market area with liquid gas wholesale market	• Competitive wholesale market without a dominant supplier • Liquid gas trading takes place at a trading hub where prices are well integrated with prices in other E/E areas

Source: Frontier

5.3.2 Lowering the cost-coverage ratio

An alternative approach is to allow for the beneficial external effect by lowering the proportion of investment costs that must be covered by shipper commitments in the market test. This would imply a greater shortfall between investment costs and shippers' WTP. The investment costs not covered by shipper's commitments would then be socialised by the TSO to all network users through the general tariff methodology. As all network users (and the consumers they serve) would benefit from the external effects, such a cost allocation is efficient.

But how much of a reduction of the cost-coverage ratio is justified on the grounds of external effects? We do not think that there is any general rule and an assessment based on the sort of indicator shown in **Table 3** is probably the best that can be done.

5.3.3 Preferred treatment of externalities

Of the two approaches, we think that an explicit assessment of the benefits is usually preferable because:

- it enables a more consistent approach to be adopted for the coverage ratio on all projects;
- if some of the investment costs is to be socialised from the commissioning date, some estimate of the external benefits is needed in any case; and
- it is more transparent to those participating in the process as a basis to determine whether investment in incremental capacity should take place.

5.4 The market test and TSO coordination

Any incremental capacity project will have costs and benefits on both sides of the IP. The costs will be incurred separately by each TSO. The revenues will be allocated on the basis of the separate entry and exist tariffs of the each TSO (the reserve prices) and agreement on the allocation of any premium over the reserve price[31].

There are a number of alternative approaches to the conduct of the market test in these circumstances:

- **one test by one TSO**: the test can be conducted by one TSO for its share of the costs and the other can make its decision without consideration of shipper commitment – implicitly relying on the other TSO. This was the approach used in the two FR-ES open seasons described in Annex 3;
- **separate tests by both TSOs**: the test can be conducted separately by both TSOs on the basis that it must be satisfied in both cases for the investment to proceed. This is the approach adopted in the case of a new interconnector where we understand the test was passed on of the Slovakian side of the IP but not on the Hungarian side; and
- **one combined test for both TSOs**: the TSOs agree on a single test with common parameters and agree that the investment decision will be made on the basis of the results.

The challenges in agreeing a single, combined market test include:

- the cost of capital of the two TSOs may not be the same, implying a different discount rates to value future revenues;
- views on the valuation of external benefits may differ; and
- the attitude of one TSO to the risks associated with uncommitted WTP may differ, leading to a different view on the required coverage ratio –

31 Under the draft framework guideline the default allocation of the premium where TSOs do not agree is 50:50.

this is particularly true in the case of MSs which provide routes for transit gas and have relatively small captive markets[32].

Where there is insufficient agreement to permit a combined test to be established, and neither TSO is willing to rely on a test conducted by the other, then two separate tests will be required. This can be difficult to present in a way that is understood by the market and could have a detrimental impact on participation.

If the need for separate tests is driven by an asymmetry of costs and benefits between the two MSs, this needs to be identified before the incremental capacity is offered to the market. It may be possible to reach agreement on some form of cost or revenue reallocation, as envisaged under the proposed Infrastructure Regulation.

5.5 Conclusions on market test

Based on the discussion above, we have reached some conclusions about the principles of the market test which might form the basis of a harmonised approach. These would be applicable without regard the option used to offer incremental capacity. The principles are:

- details of the market test need to be transparent and capable of being replicated by shippers in order to generate confidence;
- market tests based on discounted cash flows should be preferred over tests based on meeting quantity thresholds – the test should enable shippers to express potential willingness to pay above the reserve price[33] ;
- the threshold cost coverage ratio needs to be chosen on the basis of a realistic view of the time horizon over which shippers are willing to make binding commitments – such commitments transfer risk from the TSO/gas consumer to the shipper. The coverage ratio would be based on a reasonable expectation of sales of capacity beyond the horizon after the investment decision is taken;
- the market test should consider external benefit explicitly as a notional revenue flow – although such benefits are difficult to quantify, they need to be taken into account in the market test as part of the potential justification for investment. To the extent that such benefits do not

32 We recognise that within the EU legal framework, transit flows and the national market needed to be treated on the same basis but we think that, for countries where transit flows are a multiple of the national market, concerns about the impact of risk on national consumers will be difficult to ignore. This will occure where the sustainability of transit flows is less certain than national gas demand

33 This discounting approach would only be used for the market test – the usual cost allocation methodology would continue to be used for pricing.

generate revenues for the TSOs concerned, part of the project costs need to be socialised;

- market tests should be applied sequentially, starting from the first level of incremental capacity in order to determine the optimum size of the increment;
- unless the allocation process uses a fixed nominal tariff, it will usually be better to frame the test in real terms excluding inflation;
- the risk of asset stranding needs to be carefully considered and reflected in the pricing and in the target coverage ratio – this principle is important to help reduce the risk of investment in assets which may become stranded before the end of their technical life; and
- a single market test is preferable to two separate tests. If two separate tests are unavoidable the reasons need to be carefully explored before capacity is offered to the market in case they indicate a more fundamental problem that needs to be addressed beforehand.

The stylised examples set out in this section highlight how the coverage ratio is influenced by a wide range of factors. For this reason, we think decisions on the coverage ratio in the market test need to be made at national level in the context of the national regulatory regime and an understanding of shippers' appetite to make long-term commitments. Given the wide range of variables and attitudes to risk, we do not think that it would be appropriate to define an EU-wide harmonised threshold range at which investment to provide incremental capacity must be carried out, even in the context of the principles we have outlined.

6 Description of the options

This section sets out our thinking on:

- the preparatory activities that will need to precede any offer of incremental capacity;
- when offers of incremental capacity should be made by TSOs; and
- the form that such offers of incremental capacity could take.

All options described in this section are carried forward to Section 7 for assessment.

6.1 Preparatory activities - enablers

Any offer of incremental capacity by any process will need to be enabled by a number of preparatory activities. These activities are sometimes described as pre-processes.

We assume that the NC CAM and CMP decision for existing capacity are both implemented. This will mean that:

- at each IP, TSOs are agreed on the baseline capacity for the transport of gas out to the horizon year of Y+15 and how much of that capacity, if any, is available for sale in each year in the annual NC CAM auctions. This information will be published; and
- under the CMP decision, TSOs will be providing ACER with data on the utilisation of firm capacity products in place over the last year so that a monitoring report on (physical) congestion at each IP can be prepared.

In some countries, making the baseline capacity available will be an explicit part of the regulatory arrangements applicable to the TSOs at each side of an IP. It is an output that the TSO is required to provide in return for its allowed revenues.

In order to ensure efficient use of all IP capacity, we also think that TSOs need to have an agreed methodology to assess to what extent capacity could be swapped between different IPs. Such swaps between "competing capacities" can be an alternative to the provision of incremental capacity through investment and the capacity can be provided more quickly. In GB this is known as the transfer and trade methodology; it determines the "exchange rates" between IPs where there is a beneficial interaction. For example, reducing the capacity at A by 1 GWh/day would enable capacity at B to be increased by 0.8 GWh/day. Such swapping can be applied to unsold capacity or capacity held by shippers at their request.

Under EU legislation all TSOs constituted as ITOs or ISOs have to prepare a TYNDP and others may have to do so under national legislation. As noted in Section 2, TYNDPs must also be prepared at regional and EU level covering all TSOs. These plans consider the adequacy of the gas transmission system to meet gas flows under different supply and demand scenarios. The published information could include data on the extent to which IPs are expected to be physically congested under each scenario.

As part of this planning work, we suggest that TSOs should, jointly or at regional level, identify one or more investment projects to provide incremental capacity at each IP. Such work could be focussed on those IPs:

- where data on long-term capacity bookings suggest that there is likely to be demand for incremental capacity; and/or
- where the TYNDP scenarios indicate that the IP has a reasonable probability of being congested.

The investment required could include not only the provision of capacity at the IP but also essential downstream or upstream reinforcement to ensure that the IP capacity can be used to support the gas flows foreseen. This could include provision of incremental capacity at other IPs. At most IPs there may be a small number of options for providing different levels of incremental capacity. For each potential level of incremental capacity, the outcome would be:

- the incremental capacity in GWh/day to be provided at one or more IPs;
- any indications that the economic life of incremental capacity might be shorter than the technical life e.g. due to declining long-term gas demand projections or depletion of a source of gas supply;
- a description of the investment required and its location;
- a breakdown of the cost of the investment into its main components; and
- the estimated lead time needed to provide the capacity after FID[34].

These proposals would be subject to scrutiny and challenge by the relevant NRAs as part of the review process for the TYNDP. The challenges could relate to the cost of the incremental capacity or the need for investment, based on views about the scenarios or the expectation of physical rather than contractual congestion. The intention would be that, when the incremental capacity is

34 ENTSOG surveys indicate an average lead time from market test to commissioning of just over 5 years with a maximum lead time of 8-9 years in some cases.

offered, investment approval only depends on meeting the market test discussed in Section 5.

We have considered an alternative approach, as adopted in GB and described in Annexe 2, under which a gas flow model is used to identify the LRMC of a series of small increments of capacity on the basis of modelled gas flow distances and an expansion constant (£ per GWh/day/km). As explained in Section 3, this approach is based on notional investment values and relies on arrangements to incentivise the TSO to provide incremental capacity at a lower cost. On the basis of our discussions with NRAs, we do not think that this approach would be easy to implement for bundled capacity (as opposed to entry to a single hub) nor find much support among TSOs and NRAs on the continent. We return to this issue later in this section.

6.2 When to offer incremental capacity

Offers of incremental capacity at IPs have, to date, been ad hoc in character and decided by the relevant TSOs and NRAs. In the CEER consultation on market driven investment, respondents stressed the importance of regular opportunities to submit offers for incremental capacity. In the context of the planned NC CAM auctions, this also has a wider significance. If shippers know that, beyond a certain time horizon, incremental capacity will be offered, and have some indication of its cost, they are much less likely to pay a premium for capacity that exceeds the expected cost of incremental capacity. This was one of the important issued noted in Section 3 arising out of the decision to restrict NC CAM auctions to existing capacity.

We think that the following options in relation to the timing of offers of incremental capacity at IPs or VIPs are worth consideration:

- **Option I - no EU action**: the timing would be left to the good judgement of TSOs and NRAs, without any EU intervention to establish a harmonised approach;
- **Option II - mandatory biennial offering unless certain conditions met**: the proposal of a biennial offering is intended to reflect the frequency of production of EU TYNDPs. This would be the default unless certain conditions were satisfied. The suggested (cumulative) conditions which would justify not offering incremental capacity at an IP or VIP are:
  - more than 5% of existing, yearly capacity remains unsold for the period Y+5 to Y+8 following the last annual NC CAM auction of yearly capacity; or
  - less than 5% of existing, yearly capacity remains unsold for the period Y+5 to Y+8 but this has only arisen because of a TSO's

Description of the options

decision to shift unwanted capacity to one or more other IPs using a transfer mechanism as discussed under preparatory activities in Section 6.1; and

- projected physical congestion at the IP in no more than one scenario of the EU TYNDP;

- **Option III - mandatory biennial offering**: this option would require capacity to be offered at least every two years at all IPs (without conditionality).

In the context of an EU framework, the second or third option should be regarded as a minimum requirement. TSOs and NRAs could decide to offer incremental capacity more frequently and/or even if the three conditions were satisfied.

6.3 How to offer incremental capacity

We have reviewed experience in GB with integrated auctions and looked at the results of the CEER Monitoring Report on open seasons in continental Europe and the practical experience with open seasons for the illustrative projects given in Annexe 3, as well as CEER's recent consultation on demand driven investment processes. We have also considered a 'non-paper' prepared by BNetzA on possible options and discussed these ideas with a number of NRAs.

Based on these inputs, our list of the options on how to offer incremental capacity, with a focus on what needs to be harmonised at EU level, is as follows:

- **Option A - no EU action on harmonisation**: this is the baseline option of no intervention at EU level;

- **Option B – stronger emphasis on central planning**: this option places more emphasis on the planning process to assess the benefit of incremental capacity at IPs but, like Option A, does not otherwise seek to harmonise how incremental capacity is offered;

- **Option C – integrated auctions**: this option would enable integrated auctions of existing and incremental capacity by modification of the NC CAM. There are two variants of this option; and

- **Option D – open seasons**: this option would provide a binding EU framework for the conduct of OS processes. There are three variants of this option.

Our proposals on the harmonisation of market tests and the timing of offers of incremental capacity could be implemented with *any* of the above options, to the extent that TSO would probably continue to run OS processes in the absence of any EU harmonisation of this activity.

Description of the options

We have not considered as an option the placing of greater reliance on unregulated investment undertaken with Article 36 exemptions, even though these are, by their nature, 100% market-driven. The reason is a concern that these projects are designed primarily to benefit their sponsors and, by virtue of the exemptions, involve a long-period of exclusivity. This could lead to a deferral[35] of the market integration and competition benefits that are the primary justifications for EU intervention.

6.3.1 Option A – no EU action on harmonisation

As explained in Section 3, the baseline option of no intervention implies that NRAs and TSOs are free to decide on the form of offers of incremental capacity without any overall EU framework. However, on the assumption that the NC CAM is adopted in its current form, integrated auctions of existing and incremental capacity would not be possible unless there were a prior decision to invest. Open seasons are the most likely mechanism to be used, based on past experience. Such open seasons would only be able to offer incremental capacity while the processes laid down by the NC CAM would be used for all existing, unsold capacity.

6.3.2 Option B – stronger emphasis on central planning

Like Option A, this option does not necessarily seek to harmonise the way incremental capacity is offered but would expand the existing obligations on TSOs in the area of network planning.

The proposed Infrastructure Regulation already envisages an obligation on ENTSOG to develop a harmonised, system-wide cost-benefit methodology to assess Projects of Common Interest (PCI) as defined in the draft regulation[36]. Investment to provide incremental capacity is likely to qualify as a PCI at many IPs. But the requirement to assess costs and benefits could also be extended to incremental capacity at all IPs as part of the TYNDP process. This would apply a common framework to assess external benefits and leave TSOs and NRAs free to choose whether to make the FID on the basis of a market test, from the cost-benefit analysis alone or a combination of the two.

We note that categorisation of a project as a PCI does not entitle a project to any funding under the proposed Connecting Europe Facility. The award of any such finance would depend on the projects financial viability based on whether it is

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35 Exemptions are for a limited period (e.g. 20 years) so the projects revert to regulated assets after this period.

36 Notably, all projects must fall in one of the energy infrastructure priority corridors and areas and must contribute to at least one of four categories of external benefit (market integration, security of supply, competition and sustainability (biogas)). The projects that meet these criteria and will be categorised as PCIs will be decided on the basis of a procedure in the regulation.

included in the regulatory asset base of the TSO as well as the extent of commitments from shippers.

6.3.3 Option C – integrated auctions

The only existing experience of integrated auctions is in GB, as described in Section 3 and Annexe 2, where shippers buy entry capacity to deliver gas to the National Balancing Point. These auctions offer incremental capacity in small, 2.5% increments using an LRMC methodology to make an estimate of the notional cost of each increment. This approach is closely tied to:

- the basis on which costs are allocated to entry and exit points on the national transmission system; and
- the way in which National Grid is incentivised under its regulatory framework using revenue drivers to adjust the allowed revenue if incremental capacity is released.

Based on our discussions with ACER, ENTSOG and the NRAs, it is more likely that on the continent TSOs will consider a small number of physical options to increase IP capacity and NRAs will want to review the associated costs before decisions are taken on investment. Such an approach is also likely to make the necessary cooperation between TSOs easier to achieve. These points suggest that an approach which considers many small increments of capacity at costs which do not correspond to specific projects is unlikely to be an acceptable basis for harmonisation.

As explained in Annexe 2, National Grid does not use an ascending clock methodology, the approach adopted in the NC CAM. Bidders are typically offered twenty price steps, each of which corresponds to a level of incremental capacity. These price steps can be used to allocate existing unsold capacity if the market test triggering release of incremental capacity is not met. At the end of each day the aggregate demand at each price step for each quarter is published and bidders have an opportunity to assess if the test has been met[37]. The following day they may adjust their bids on the basis of an expectation of how much capacity will be released. The process continues for up to 10 days or until a stable set of bids has been achieved, whichever is the shorter.

The key point is that shipper demand is, to some extent, a function of the capacity to be made available. There is likely to be a greater WTP when capacity is in short supply than when it is plentiful. For example, with scarce capacity, shippers might expect a sustained price differential between two entry/exit systems on the continent supplied from different sources of gas and be willing to

37 To be clear, there is no formal announcement by NG but shippers are free to reproduce the calculations using the published end of day data on aggregate demand at each price point.

pay up to their estimate of this price differential for capacity. However, they may not expect such a price differential to continue if capacity was doubled and therefore not be willing to pay any premium over the reserve price. This implies that we cannot simply take demand data from the NC CAM auctions of *existing* capacity, assume it will also apply to incremental capacity, and use it as the basis for a market test.

In the context of the ascending clock methodology used in the NC CAM, we see two ways in which these considerations could be addressed:

- **Option C1 – single offer with integrated market test**: the market test is integrated into the software and the results are available in real time so that bidders can adjust their demand for annual capacity during each round if it is sensitive to the quantity of capacity released[38]. There is a single reserve price and a single clearing price for (unsold) existing capacity and, if the market test is passed, existing and incremental capacity. Guidance could be provided beforehand to indicate that a successful market test would require significant demand to be placed at, or above, specific price steps for a number of years; and
- **Option C2 – parallel offers with a separate market test**: for each year, yearly capacity would be offered with different supplies of capacity (e.g. unsold existing capacity only, existing plus incremental supply level 1 and existing plus incremental supply level 2) in parallel ascending clock auctions. Bidders would express their demand for the products for each potential supply in each round with a unique clearing price being determined in each case. If NRAs wish it, there could be different reserve prices for each capacity offering. Auctions offering incremental capacity are much more likely to close at the reserve price. The market test would be done after closure of the auctions to see whether to release any incremental capacity and, if appropriate, how much[39]. Capacity allocation would reflect the aggregate demand and the clearing price for the level of capacity released, with the other results being discarded.

An example of Option C2 is shown in **Figure 10**. In the first 4 years, only existing, unsold capacity of 150 GWh/day is offered. The auction clears at a higher price in Y4 than in Y1 (pale green highlighted cell) as WTP increases over time. In Y5, the lead time for executing investment to provide incremental

38 Please note that this option is put forward as a concept. Considerably more work would be needed to confirm that this concept would form the basis of a stable convergent process.

39 In Option C2 there is no need to bidders to adjust their bids in response to the result of a market test outcome because they have the opportunity to express their demand curves against each possible supply of capacity. Assuming their bids reflect their true valuation of capacity under each supply level, they will be indifferent to the outcome of the market test.

capacity, both the existing, unsold capacity and existing plus incremental capacity of 50 GWh/day (a total of 200 GWh/day) are both offered separately. The existing capacity clears at a still higher price while the offer with incremental capacity clears at a lower premium (pale brown highlighted cell) over the reserve price which is assumed in this illustration to be a floating tariff. A similar result occurs in the following year. The clearing price in the auction result with incremental capacity is used in the market test to determine whether to release and allocate this capacity.

Figure 10. Integrated auction with parallel offers from Y5 (Option C2)

		Y1		----------	Y4			IC = 0	Y5	IC =50			IC = 0	Y6	IC =50		etc
Price step	Price	Supply	Demand		Supply	Demand		Supply	Demand	Supply	Demand		Supply	Demand	Supply	Demand	
21	2.0	150			150			150		200			150		200		
20	1.9	150			150			150		200			150		200		
19	1.8	150			150			150		200			150		200		
18	1.7	150			150			150	140	200			150		200		
17	1.6	150			150			150	170	200			150	145	200		
16	1.5	150			150			150	200	200			150	180	200		
15	1.4	150			150	*135*		150	240	200			150	230	200		
14	1.3	150			150	*155*		150	300	200			150	290	200		
13	1.2	150			150	*195*		150	350	200			150	335	200		
12	1.1	150			150	*250*		150	360	200			150	355	200		
11	1.0	150			150	*300*		150	370	200			150	365	200		
10	0.9	150	*145*		150	*360*		150	380	200			150	380	200		
9	0.8	150	*190*		150	*365*		150	395	200	*198*		150	387	200		
8	0.7	150	*250*		150	*370*		150	398	200	*240*		150	390	200	180	
7	0.6	150	*280*		150	*380*		150	405	200	*350*		150	395	200	205	
6	0.5	150	*300*		150	*380*		150	420	200	*370*		150	420	200	260	
5	0.4	150	*310*		150	*385*		150	440	200	*395*		150	439	200	350	
4	0.3	150	*310*		150	*390*		150	442	200	*405*		150	440	200	400	
3	0.2	150	*315*		150	*395*		150	445	200	*440*		150	445	200	435	
2	0.1	150	*320*		150	*400*		150	448	200	*445*		150	447	200	440	
1	0	150	*320*		150	*400*		150	450	200	*450*		150	450	200	450	

Source: Frontier based on an ENTSOG illustration

Where capacity is allocated at a nominal price that does not then change, as in the GB auctions for entry capacity described in Annexe 2, any subsequent changes to the reserve price applied to unsold capacity for a given year have no effect on existing capacity holders.

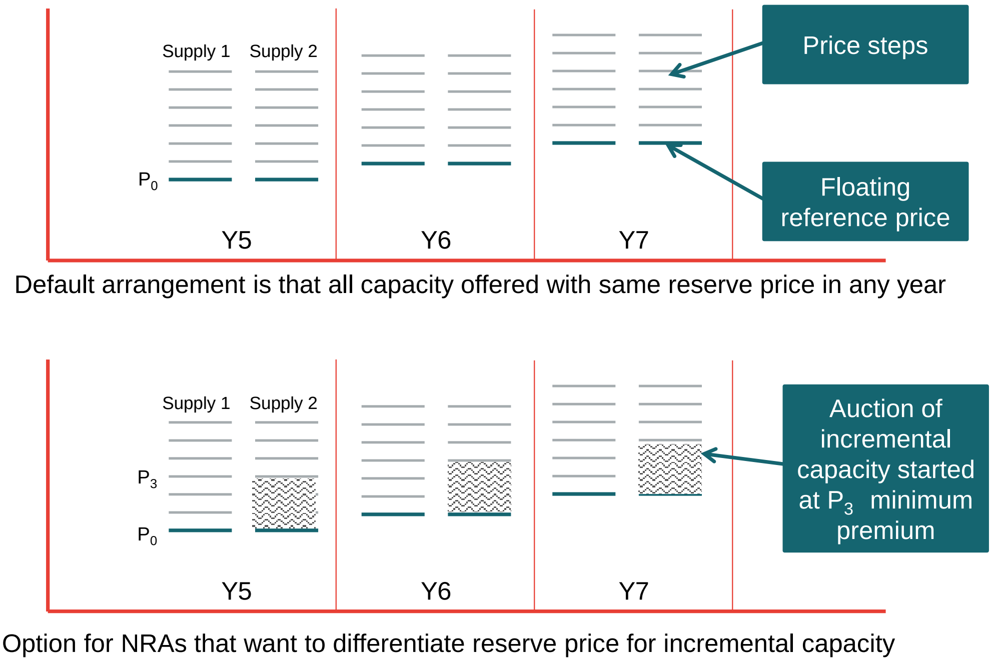
Where a floating tariff is adopted and incremental capacity is released, the reserve price – based on the TSOs cost allocation methodology - would become the floating tariff for *all* capacity held for that year. This approach would reflect economic thinking that all should pay a tariff related to a measure of LRMC. If the unit cost of incremental capacity is higher than that of existing capacity, the price would increase for all. However, we understand that some NRAs might want to protect existing capacity holders from such higher prices while preserving the principle of a floating tariff[40]. This could be done by expressing the minimum price for incremental capacity as a number of price steps above the

40 One reason for this is that if the increase in capacity prices exceeded a certain level, it might under some jurisdictions give shippers grounds to terminate existing contracts.

floating tariff (a minimum premium[41]) so that there is no change in the price payable by existing holders of capacity. This is shown in **Figure 11**. In the illustration "Supply 1" refers to an offer of existing, unsold capacity and "Supply 2" to an offer of existing, unsold capacity with incremental capacity. In the optional arrangement shown at the bottom of the figure, the auction with Supply 2 starts at a minimum premium.

A similar effect could be achieved by informing auction participants in the auction that the market test for release of incremental capacity would require the auction to clear at price step 3 or higher.

Figure 11. Reserve prices in integrated auctions for incremental capacity



Source: Frontier

Such an approach would be asymmetrical in that it would provide flexibility for incremental capacity to have a higher unit price than existing capacity (on the basis of higher unit costs) but not for lower unit prices if incremental capacity could be added relatively cheaply. Symmetry would, in principle, be possible with the same approach but using negative price steps i.e. a starting price below the floating tariff. This would be a difficult concept to accommodate and is likely to be seen as unfair by existing holders of capacity.

41 In this case the minimum premium would reflect underlying costs and not a premium to reconcile supply and demand in an auction.

Another consideration is the horizon for shipper commitment. If new investment has, typically, a five year lead time, then the 15 year horizon of the NC CAM long-term auction would limit the horizon for shipper commitments to 10 years. This could be extended to 15 or 20 years by modification of the NC CAM if it were considered to be desirable to assess the potential commitment over a longer term horizon. As explained in Section 5, this has an impact on the coverage ratio in the market test.

A final point, concerning the application of the market test where there is more than one level of incremental capacity is addressed in the text box below.

Box: The market test and incremental capacity levels

If there is only one supply level of incremental capacity, the market test can be applied by comparing the discounted revenue stream attributable to the incremental capacity to the project cost to see if coverage meets the criterion established by the NRAs and TSOs. But if two supply levels are possible, depending on the scale of the project, the solution is less obvious. Suppose that at Supply Level 1 there is excess demand at the reserve price, the auction clears at P_5 and the market test is easily passed. This WTP provides evidence of the benefits available to shippers. At Supply Level 2, demand can be fully satisfied at the reserve price. The market test for Supply Level 2 could compare the change in revenues at clearing prices in both auctions against incremental costs in comparison to Supply Level 1. This would reflect the change in the financial position of the TSO. However a further allowance would also need to be made for the benefits to shippers with Supply Level 2 which were not reflected in the price paid. The idea behind this approach is to expand the capacity at the IP until a point where incremental benefits approximate incremental costs.

6.4.1 Option D – open seasons

Under Option D we first set out the elements of an open season that, in our view, would need to be harmonised - as the illustrative projects in Annexe 3 demonstrate, TSOs and NRAs have approached open seasons in many different ways in the past.. These elements will also apply to any variant of the open season. We then consider the characteristics of the potential variant options.

The conduct of an indicative phase of an open season, before the binding phase, would be discretionary. It would depend on how confident the TSOs were that the scale and configuration of incremental capacity was attuned to the market demand. We note that data from NC CAM auctions of existing, unsold capacity would to some extent provide an indication of potential demand. The binding phase of the open season would be mandatory.

Description of the options

The essential elements of the binding phase of an open season would be as follows:

- joint offers of annual bundled capacity, at one or more IPs, by the TSOs concerned, on a basis which had the prior approval of the relevant NRAs – the products would be consistent with those defined in the NC CAM;
- an invitation to register interest in the process, open to all existing and potential shippers;
- preparation of a draft information memorandum for approval by NRAs setting out:
  - the different levels of incremental capacity to be offered at the IP(s) or VIP(s) and their relationship;
  - the estimated investment cost of each incremental capacity level;
  - when the capacity would be made available, based on an implementation timetable;
  - how the capacity can be used – probably by reference to standard documents
  - the tariff for the capacity and, if floating, a projected tariff level, based on an explicit methodology and stated assumptions;
  - a description of the market test that will be applied in order to release capacity based on the principles set out in Section 5;
  - a description of to how submit binding offers for the incremental capacity – potentially extending beyond the 15 year NC CAM horizon;
  - a description of how incremental capacity will be allocated if released; and
  - the timetable for the whole process that provides scope for queries to be answered before binding offers are submitted.
- approval of the draft Information Memorandum by the relevant NRAs before issue;
- an allocation process based principally on demand bid at different price steps in each year but scope to make offers conditional on acquiring capacity at one or more other IPs, if offered at the same time – see text box below; and
- publication of the results to the same standard as under the NC CAM auctions.

Box: Linked bids across two IPs

Giving shippers the right to link their bids for capacity across two IPs is not difficult for a static auction and a price ladder at each IP. This was demonstrated in the FR-ES (2015) case study reported in Annexe 3. In a static auction bidders express their demand for capacity at each price step on the ladder and then submit their bids – there is, in effect, only one round and no feedback. Capacity is allocated at the price where demand is equal or less than supply of capacity. If, on this basis, a bidder with a linked bid is allocated capacity at one IP and not at another, the allocation is withdrawn and the results of the auction recomputed using the remaining bids. In principle, it is possible to give bidders withdrawal rights in an ascending clock, dynamic auction on the basis of a declared link to bids at another IP. However, in this auction format, such rights would complicate the auction process and their inclusion was rejected during development of the NC CAM by ENTSOG.

There is a further issue about whether shippers would be permitted to link bids explicitly across years in order to guarantee being allocated a continuous strip of capacity or nothing. This was considered in the course of development of the NC CAM where it was noted that, as long as shippers are willing to bid the same demand at all price points in all years, then they can guarantee a continuous strip. In other words, it is the shippers' own actions which determine whether capacity is allocated in a continuous strip. For this reason, linked bids in the NC CAM are not permitted. It has sometimes been practice in OS processes where bidders have simply been asked to express demand at a fixed tariff to deal with excess demand by giving preference to those with requests for capacity over the longest period. If such an approach is considered undesirable, it could be explicitly prohibited.

Based on the documents we have reviewed and on our discussions with Steering Group Members, we have identified three possible variants of the open season option:

- **Option D1 – offer of incremental capacity only**: the open season would be run as a separate process for determining whether to invest in incremental capacity and, if the market test was passed, would allocate the incremental capacity based on the binding requests for capacity received. The reserve price would be specific to the incremental capacity. The long-term NC CAM auction for existing, unsold capacity would continue as under the existing NC CAM rules;
- **Option D2 – combined offer of incremental and existing, unsold capacity**: as for Option D1 except that the open season would offer incremental capacity *together* with any existing unsold capacity –

reflecting the fact that shippers are interested in the capacity product and not whether it already exists or is considered to be incremental. The reserve price could be common to both unsold existing and incremental capacity. The open season would invite offers at a number of price steps, resembling the price increments in the NC CAM, to allow shippers to express WTP above the reserve price. However, the process would not take the form of an ascending clock auction. If the market test was satisfied, all existing capacity would be allocated (using the price steps in the event there was excess demand at the reserve or minimum offer price) and the subsequent NC CAM auction of yearly capacity would be cancelled; and

- **Option D3 – combined offer of incremental and existing, unsold capacity with allocation under the NC CAM**: the capacity offered would be the same as in Option D2 but shipper commitments or bids in the open season would only be used for the purpose of the market test, not for capacity allocation. All bids received (in other words, each shipper's demand at each price step) would remain binding after the OS and be entered into the subsequent NC CAM auction which would serve to determine the final allocation of capacity. Shippers that participated in the OS would be able to increase (*but not reduce*) their bids for capacity in the NC CAM auction. Shippers that had not participated in the OS would also be able to submit bids. The clearing price would be the same, or higher, than that implied by the open season process.

The primary rationale for the two step process for submission of binding requests for capacity and allocation in Option D3 would be to ensure a consistent basis for capacity allocation using the NC CAM rules. This provides assurance that the process will be non-discriminatory. It also means that the final allocation will follow a common timetable at all IPs, which could be helpful to some participants.

Some specific points to note about Options D2 and Option D3 are:

- an OS process should give shippers the opportunity to express their demand at different price levels. In Option D2 this would be the basis of allocation. In Option D3, these bids would remain binding on shippers after completion of the open season but the only obligation on the TSOs would be to enter the bids in the subsequent NC CAM auction for yearly capacity. The reserve price and price steps would need to remain the same. Given the auction calendar prescribed by the NC CAM, bids could remain binding for up to one year;

- If a shipper reduced demand to zero at, say, price step P_2 in the OS process and the subsequent NC CAM auction had excess demand at this price, implying a clearing price above P_2, then the shipper would be allocated no capacity unless he or she submitted further bids in the NC CAM process. Shippers not allocated any capacity due to a reduction in demand below the auction clearing price would not be entitled to any compensation; and

- if the principles on which these OS processes are based, including the use of price steps above a reserve price to permit shippers to express WTP, are harmonised at European level, many of the concerns that provide the rationale for Option D3 would be addressed. However, any harmonisation of the should not go so far that it undermines the flexibility of the OS approach – if the OS approach is made to resemble an NC CAM auction too closely, there would be little purpose in having this as a distinct option.

We take all options set out in this section, including the variants of Options C and D, forward to the next section for assessment.

7 Assessment of impacts and comparison

We now assess the impact of the different options presented in Section 6 on the basis of the criteria given in Section 4, which are intended to reflect the main objectives of EU intervention. We then provide some quantitative illustration of the overall economic impact of EU intervention and briefly review social and environmental implications.

We first consider the options concerning when incremental capacity should be offered before turning to the options related to the form in which it is offered.

7.1 Options concerning when to offer incremental capacity

The options we presented in Section 6 were:

- Option I - no EU intervention;
- Option II - biennial offers at all IPs unless certain conditions are met; and
- Option III - mandatory biennial offers at all IPs.

7.1.1 Option I - no EU intervention

Our assessment of this option is as follows:

- **timely and efficient investment**: without an overall EU framework, incremental investment is less likely to be offered at the right time across the Union. Most NRAs and TSOs will do a good job but delays are more likely without any EU framework. Integration of the EC gas market may take place more slowly;
- **minimisation of the risk of stranding**: this criterion is not relevant the timing of the offer of incremental capacity;
- **avoidance of cross-subsidies and discrimination**: no intervention would mean offers of incremental capacity would be less predictable and this could lead to shipper paying excessive premia in long-term NC CAM auctions;
- **transparency**: without EU intervention, the timing of offers of incremental capacity would be less predictable and transparent;
- **proportionality**: not relevant without intervention;
- **keeping administrative burdens low**: not relevant without intervention; and
- **ease of implementation:** not relevant without intervention.

7.1.2 Option II - biennial offer at all IPs unless certain conditions are met

Our assessment of this option is as follows:

- **timely and efficient investment**: with mandatory requirements on when to offer incremental capacity, unless certain conditions are met, it is more likely to be offered at the right time across the Union, giving shippers the opportunity to make sufficient commitments for the investment to proceed. EC gas market integration will be advanced;
- **minimisation of the risk of stranding**: this criteria is not relevant the timing of the offer of incremental capacity;
- **avoidance of cross-subsidies and discrimination**: with more predictable offers of incremental capacity the risk of shippers paying excessive premia in long-term NC CAM auctions would be reduced;
- **transparency**: the timing of offers of incremental capacity would be more predictable and transparent;
- **proportionality**: if the conditions are well designed, this intervention seems proportionate given the overall objectives; and
- **keeping administrative burdens low**: TSOs only need to offer incremental capacity when there are good indications that it would be of interest to the market. This would avoid the work involved in developing projects to provide incremental capacity for which there was unlikely to be any demand; and
- **ease of implementation**: subject to the administrative burdens noted above, this approach would be easy to implement.

This approach strikes a balance between the frequency of offers and the work involved for TSOs.

7.1.3 Option III - Mandatory biennial offer at all IPs

Our assessment of this option is the same as that for Option II except in the following areas:

- **transparency**: biennial offering under all conditions would be more transparent;
- **proportionality**: mandatory offering in all circumstances may go further than is required to realise the objectives and thus be disproportionate;
- **keeping administrative burdens low**: TSO would need to identify projects and offer incremental capacity every two years even in cases where there was unlikely to be any demand for the capacity. This would involve work for little purpose; and

Assessment of impacts and comparison

- **ease of implementation**: subject to the administrative burdens noted above, this approach would be easy to implement.

7.1.4 Conclusion on when to offer incremental capacity

Based on these considerations, our assessment indicates that Option II, biennial offering of incremental capacity unless certain conditions are met, is the preferred approach.

7.2 Options concerning how to offer incremental capacity

The options with respect to the manner in which incremental capacity is offered, as described in Section 6, were:

- Option A: no EU action on harmonisation;
- Option B: stronger central planning;
- Option C: integrated auction with two variants (single offer with integrated market test or parallel offers with a separate market test); and
- Option D: open seasons with three variants (separate offer of incremental capacity only, combined offer of existing and incremental capacity and combined offer with final allocation under the NC CAM).

7.2.1 Option A: no EU action on harmonisation

Our assessment of this option is as follows:

- **timely and efficient investment**: without a harmonised EU framework concerning offers of incremental capacity, market-driven investment decisions would rely on the result of open seasons, with no option to use integrated auctions. The design of open season processes would be a matter for local TSOs and NRAs, with lower likelihood that all would lead to timely and efficient investment. EC integration may take place more slowly than with some harmonisation;
- **minimisation of the risk of stranding**: this depends primarily on the preparatory work to decide the economic life of the asset and to design the market test;
- **avoidance of cross-subsidies and discrimination**: offers of existing and incremental capacity would have to take place separately, potentially leading to different prices for the same product offered at about the same time;
- **transparency**: the separation of offers of existing and incremental capacity would be less transparent;

- **proportionality**: not relevant to this option;
- **keeping administrative burdens low**: not directly relevant to this option but it is worth noting that without harmonisation shippers would have to become familiar with a more diverse range of open seasons and bid separately for existing and incremental capacity which would be burdensome; and
- **ease of implementation:** requires no implementation.

7.2.2 Option B: stronger central planning

Our assessment of this option is as follows:

- **timely and efficient investment**: this would depend very much on the quality of the cost-benefit analysis undertaken and the quality of any open season processes that were undertaken. Clear identification of the external benefits would promote efficient investment and EC gas market integration;
- **minimisation of the risk of stranding**: the cost benefit analysis would require TSOs and NRAs to consider the stranding risk in a more transparent manner;
- **avoidance of cross-subsidies and discrimination**: any offers of existing and incremental capacity would have to take place separately, potentially leading to different prices for the same product offered at about the same time;
- **transparency**: the separation of offers of existing and incremental capacity would be less transparent but there would be a clear identification of external benefits;
- **proportionality**: stronger central planning would be a very modest extension to the obligations already expected to apply under the Infrastructure Regulation;
- **keeping administrative burdens low**: ENTSOG, TSOs and NRAs would have some additional work to do in relation to planning. The remarks under Option A concerning the burden on shippers also apply; and
- **ease of implementation:** measuring benefits for gas transportation projects is not easy but the methodology to do so is being developed by ENTSOG for the purposes of the planned Infrastructure Regulation.

7.2.3 Option C: integrated auction with two variants

Our assessment of this option is as follows:

- **timely and efficient investment**: simultaneous offering of existing and incremental capacity is likely to encourage efficient, market driven investment in incremental capacity where there are no alternative options or interactions between IPs that need to be considered as part of the market test. This option is compatible with separate identification of external benefits and use of the results in the design of the market test;
- **minimisation of the risk of stranding**: this depends primarily on the preparatory work to decide the economic life of the asset and to design the market test;
- **avoidance of cross-subsidies and discrimination**: offers of existing and incremental capacity would take place simultaneously, leading to a single price for the same product;
- **transparency**: the offer would take place under modified NC CAM rules which have been designed to ensure transparency. Option C1 may be less transparent than Option C2 due to potential uncertainties with regard to the impact of integrating the market test;
- **proportionality**: extending the NC CAM process to address incremental capacity seems proportionate but this option may not suit all circumstances so it would not be appropriate to mandate as the only option. Requiring the test to be integrated into the software, as in Option C1, would remove any scope for reflection on the results by NRAs which could be considered to be disproportionate;
- **keeping administrative burdens low**: Option C1 The integration and harmonisation of the offers of incremental capacity would reduce the effort required from shippers. However, Option C1 may require more effort on the part of shippers who would have to follow the progress of the auction more closely; and
- **ease of implementation:** Option C1 may be technically difficult to implement in the context of an ascending clock auction, the chosen method for yearly capacity in the NC CAM. Option C2 does not have this issue and would be much simpler to implement.

Option C2, using parallel offers of yearly products with different overall supply volumes, is the preferred variant of this option.

7.2.4 Option D: open seasons with three variants

Our assessment of this option is as follows:

- **timely and efficient investment**: open season arrangements are a well-established approach to making market-driven investment decisions and can be adapted to deal with complex situations involving different project options and interactions between IPs. This option is compatible with separate identification of external benefits and use of the results to design the market test. The ability of open seasons to allow shippers to link bids for capacity at more than one IP is positive for EC integration. While, the two stage process of Option D3 could deter some market participants it could be used by TSOs to proceed with obtaining permits before the capacity is finally allocated;

- **minimisation of the risk of stranding**: this depends primarily on the preparatory work to decide the economic life of the asset and to design the market test;
- **avoidance of cross-subsidies and discrimination**: Option D2 avoids the problem shippers would face if existing and incremental capacity is offered separately, as under Option D1. Option D3 could require allocation based on NC CAM rules but shippers participating in the open season are likely to consider the two stage allocation as unfair in favouring those who did not participate originally;
- **transparency**: an integrated open season as in Option D2 for existing and incremental capacity is more transparent than Option D1. The complexity of Option D3 means that this is likely to be considered as less transparent;
- **proportionality**: this option builds on existing arrangements and harmonises them to promote good practice and reduce the burden for participants. However, there seems to be no good argument to justify requiring all MS to use this option at all IPs in preference to Option C; and
- **administrative burdens low**: this would develop and harmonise a well-established process. Option D2 would create a single process for existing and incremental capacity, easing the burden for shippers. Option D1 and Option D3 would both require shippers to participate in two different processes. A benefit of Option D3 is that the NC CAM rules would not need to be amended to enable OS processes;
- **ease of implementation keeping:** open seasons are a well-established method of conducting a market test and of allocating capacity. In Option D3 shippers may have issues with bids remaining binding for up to one year before the allocation of capacity is decided.

On balance, Option D2 is the preferred version of this option. However, we are aware that Fluxys-TENP launched an OS using a process that resembles Option D3 in December 2012. Incremental capacity between Italy and NW Europe is on offer. Feedback from this OS could be taken into account in the subsequent work by CEER on incremental capacity.

7.3 Comparison of options and overall impact

We have drawn the results of the assessment above into an overall comparison by scoring each option against the seven criteria. We have assigned a maximum score of 10 against each criterion except "timely and efficient investment" which is scored out of 25 and "minimising the administrative burden" and "ease of implementation", both of which are scored out of 5. This gives a maximum score of 75. The results are set out in **Table 4**. As noted previously, there is some overlap between some of the criteria used. The second column shows the maximum score for each criterion and the body of the table shows individual scores for each option. Total scores are given in the last row.

Table 4. Assessment of options

	Max	A	B	C1	C2	D1	D2	D3
Efficient/timely investment	25	14	17	21	21	23	23	22
Lower stranding risk	10	5	6	8	8	8	8	8
No X subs or discrimination	10	5	5	8	8	6	8	7
Transparency	10	5	6	7	8	8	8	7
Proportionality	10	9	8	7	7	7	7	6
Min admin burden	5	2	3	3	4	2	4	3
Ease of impl't'n	5	5	4	2	4	3	3	2
Total score	75	***45***	***49***	***56***	***60***	***57***	***61***	***55***

Source: Frontier

The results indicate that:

- all of the options offer advantages over Option A, i.e. no EU action to harmonise the arrangements;
- both Option C integrated auctions, and Option D, open seasons, are superior to reliance on cost-benefit analysis alone, primarily because coordinated, market-driven investment is more likely to be timely and efficient (providing externalities are appropriately addressed in the market test);

- within Option C, the parallel offers with a separate market test (Option C2) scores better than the option of integrating the market test into the software (Option C1); and
- within Option D, the combined offers of existing and incremental capacity, with allocation within the open season and no subsequent NC CAM auction (Option D2) does better than the other options, primarily due to the likelihood that this will be more acceptable to shippers. This conclusion needs to be reviewed on the basis of feedback from the current Fluxys-TENP auction which employs an approach close to that of Option D3.

This form of scoring does not capture the point that all three of the main harmonisation options could be valuable depending on the circumstances and have a complementary, rather than a mutually exclusive, character. Thus:

- cost-benefit analysis can help to identify externalities in all cases and thus improve the detailed design of the market test for market-driven investment. For certain categories of investment, such as the elimination of entry/exit systems within an MS, it may be the primary tool because such investment does not lead to any marketable capacity;
- integrated auctions provide a relatively simple way to offer incremental capacity under NC CAM rules where there are no complex options to be considered or demand for linking bids at different IPs (i.e. no more than two TSOs are involved), subject to appropriate modification of the current NC CAM rules; and
- open seasons are a familiar way to offer incremental capacity and provide great flexibility to deal with more complex situations where there are different options and interactions between capacity offered at more than one IP involving more than two TSOs.

For this reason, we think that EU action to provide a common framework enabling all of the preferred options would be desirable. The options would be combined with the proposals concerning the principles of the market test and rules concerning when incremental capacity must be offered.

7.3.1 Quantitative assessment of economic impact

We now consider in quantitative terms the potential economic impact of an EU harmonisation initiative aimed at optimising investment in incremental capacity. The focus is on the set of preferred options rather than individual options – we do not think that there are sufficient data to estimate the impact of each individual option. Our intention is to illustrate the magnitude of the benefits from EU harmonisation and to show that these are large relative to the costs involved, which we think are quite modest.

The principal benefits of the proposed measures are expected to be:

- earlier commissioning of worthwhile investment as a result of more regular offering of incremental capacity on the basis of harmonised procedures for such offers, using either integrated auctions or, alternatively, OS processes where the project is more complex; and

- elimination of some investments that would otherwise become stranded. By pricing incremental capacity on the basis of a realistic estimate of its economic life, shipper commitments may prove to be insufficient for a decision to proceed in comparison to commitments when prices are based on an assumption of a longer life[42]. The additional saving is the full investment costs avoided, less the benefits that would have otherwise have arisen if the project had been undertaken.

With regard to the first point, the focus is on the cost and benefit of *bringing forward* investment in incremental capacity as a result of EU harmonisation. We therefore need a measure of the annual benefits and some indication of the annualised cost.

To estimate benefits, we would ideally like to have projections of the differences in gas prices across each IP before and after investment in incremental capacity for all years of the operating life of the capacity. None of the illustrative projects we have considered provide data of this nature or, indeed, any quantification of the benefits of the investment although it is clear, for example, that the merits of the DE-PL and AT-SI incremental capacity projects described in Annexe 3 arises from existing gas price differentials. We have therefore proceeded as follows:

- the Commission's market observatory for energy produces a quarterly report on gas prices across Europe. The map of wholesale prices, reproduced in Annexe 4, shows that there are significant price differentials between a number of countries within the EU, with the smaller markets often having higher prices;

- we have assumed, conservatively, that incremental capacity might have an impact on gas prices in some 10% of the EU market, equivalent to total demand of about 500 TWh ;

- to gauge the cost of incremental capacity, we have considered the cost of €192 million reported by the Slovakian and Hungarian TSOs to the European Commission[43] for a new 115kms interconnection and the expansion constant used by National Grid in GB as the basis for its LRMC estimates. These sources produce figures of €3000/

42 If the shipper commitments are sufficient with the higher prices, this represents a transfer of shipper surplus to the TSO and ultimately to consumers.

43 See the EEPR information sheet at http://ec.europa.eu/energy/eepr/projects/files/gas-interconnections-and-reverse-flow/slovakia-hungary-sk-hu_en.pdf

GWh/day/km (National Grid[44]) and €11,000/GWh/day/km from the Hungary-Slovakia interconnection. Assuming a 40 year life and the EC's standard discount factor for Impact Assessments of 4%, we obtain annualised costs in the range €155-555/GWh/day/km/y;

- we consider investing in the potential to supply 5% of the target market (25 TWh from 5% of 500 TWh) with new supplies of gas from the lower cost countries and suppose that on average that about 500kms of incremental cross-border[45] capacity will be needed to transport this gas (by way of reference, the distance from Brussels to Vienna is about 1000 kms). Assuming capacity utilisation of 70%, we obtain an annual cost of between €7.5 and €27 million for the incremental capacity needed (equivalent to 98 GWh/day);
- suppose, first, that the capacity is purchased by shippers and that the 5% market share does not have any impact on prices in the destination area or source area and that these shippers are, on average, able to capture a price difference of up to €5/MWh. This would yield annual benefits of €125million, a multiple of 4.5 times the highest estimate of the incremental annual costs; and
- suppose, second, that the 5% of additional gas shifted the gas supply curve to the right sufficiently to lower wholesale gas prices in the destination countries by €1/MWh, still without any price change in the much larger source countries, then annual benefits to consumers are €500 million while the benefit to shippers would fall to €100m, a total of €600 million[46]. The total benefit is a multiple of over 20 times the highest cost estimate.

This very simple analysis is based on a large number of assumptions but we think is sufficient to illustrate the potential benefits of incremental capacity given the present wholesale gas price differentials in Europe.

In addition to these direct benefits, we would also expect to find the following external and indirect benefits:

- improved security of supply;
- more potential for new entrants to enhance competition; and
- some possible stimulation of economic growth via multiplier effects arising from lower gas prices.

44 This value uses an exchange rate of €/£ of 1.25 to translate the expansion constant to euros.

45 This will also include incremental capacity in the national networks upstream and downstream of the border.

46 These benefits are assumed to be sustained over time and that the discounted value of any reduction in future benefits due to the economic life or the pipeline occurring one year sooner is insignificant.

With regard to stranded capacity, we need an estimate of the cost of the projects that would no longer proceed because of a more accurate assessment of their economic life and of the benefits that would be foregone – benefits that would have been sufficient to generate shipper commitments had capacity prices been lower. There are no directly pertinent data available to make such estimates but as an approximate indicator we looked at the total non-FID transmission investment in the 2011-20 EU TYNDP of €58 billion. Assuming this is concentrated in the last 6 years of the plan, the annual cost is about €10 billion. If the proposals were to eliminate investment equivalent to 0.5% of this amount, the annual savings would be €50 million per annum.

These illustrative results are summarised in **Table 5**.

Table 5. Summary of illustrative annual costs and benefits

	€m	€m
Cost of capacity (500kms assumed)		7.5 - 27
Potential benefits to consumers (€1/MWh)	500	
Potential benefits to shippers (€4/MWh)	100	
Saving from lower stranding (0.5% of capex)	50	
Total annual benefits		650
Net range of illustrative annual benefits		623 - 642

Source: Frontier analysis

7.3.2 Social and environmental impact

We have also considered the social and environmental implications of the preferred options.

An efficient gas market served by a European transmission infrastructure accommodating all economically reasonable and technically feasible demands for capacity is most likely to provide gas to consumers at fair prices. The social impact is therefore most likely to correlate with the economic criteria in our assessment matrix such as timely and efficient investment. The proposed measures are therefore more likely to lead to fairer gas prices for consumers than an absence of any EU harmonisation.

There are two potential environmental implications:

- the benefits of harmonisation rest to a great extent on earlier investment so that the environmental impact of the new infrastructure will be experience earlier as well. However, projects will follow planning procedures determined by separate legislation and we assume that those projects which gain permits will have an acceptable environmental impact; and

- a number of countries have plans to increase production of biogas. The market for this gas can be improved significantly if it is blended with natural gas and transported throughout the network. Although none of our proposals specifically addresses this issue, we think it is fair to assume that a better integrated network will be better able to accept biogas than one with a greater number of bottlenecks.

7.4 Estimated costs of harmonisation

The cost of harmonisation will include:

- the cost of the work required to debate and agree the changes and then to implement them by code modification or similar regulatory measures;
- the cost of preparatory work by TSOs required to enable offers of incremental capacity to the extent that this is additional to offers that would have taken place without harmonisation;
- the cost of any adjustments required to the PRISMA capacity allocation platform, currently being set up to implement the NC CAM on behalf of 19 TSOs to enable offers of incremental capacity using integrated auctions; and
- the costs incurred by shippers participating in offers of incremental capacity to the extent that these are additional to those which would have taken place without harmonisation.

We consider each of these points in turn.

Work required to agree the detailed harmonisation measures and then to prepare the relevant regulations needs to be considered in the context of the on-going work programme on the Network Codes for which substantial teams are already in place. The incremental work, including consultation, might be of the order of 100 person-months. Assuming an hourly cost of €50, this would represent a labour cost of about €0.8m[47]. If this is amortised over 4 years the annual cost is €0.2 million.

With regard to the cost of preparatory activities, we have consulted ENTSOG who in turn consulted TSOs. Although due to the holiday period the response

47 The impact assessment for the Infrastructure Package uses a labour cost of €25.63 per hour. We have doubled as this assumption seems low given the nature of the work involved in this case.

was limited, the estimate seems to us to be plausible. The cost of preparatory work for projects with a value exceeding €50 million was put at:

- about 0.2% of project cost where the requirement could be met primarily from internal resources (e.g. for work on simple upgrades to the existing network);
- in the range 1-2% where significant external work and engineering activities were needed (e.g. for new pipelines requiring feasibility studies and permitting).

It is difficult to judge how much of these costs would be truly additional. As argued in relation to benefits, we think that EU harmonisation is most likely to enable incremental capacity projects to be brought forward rather than to identify new projects that might never have taken place. In other words, costs will be incurred sooner than otherwise. If we consider projects with a value of €10 billion (the approximate annual investment in non-FID transmission projects in the last EU TYNDP), preparatory costs of 1% would be €100 million. Incurring these costs one year earlier at the standard discount rate of 4% would generate additional costs of just over €4 million.

With regard to PRISMA, our proposed design for integrated capacity auction involves offering the same yearly capacity product with different supply levels of supply. The mechanics of the auction are unchanged. In the context of a platform which is being set up[48] to handle a great many auctions at regular intervals for yearly, monthly and daily capacity, we do not think that there will be significant incremental platform costs. We have allowed for €1 million of development, amortised over 4 years, and an additional €0.25million of operating costs.

With regard to the cost of participation, we think that shippers who participate in integrated auctions would, in any case, have taken part in the existing NC CAM auction and placing bids in the additional price ladders will not take significant time. Shippers are likely to incur some costs when incremental capacity is offered by open season, although, as argued above, our view is that the impact of EU harmonisation will be to bring forward costs that would have been incurred in any case. We think that the additional costs for shippers in aggregate might be about a half of those incurred by TSOs or €2 million (€4m/2). It is even possible that there could be a net saving to the extent that, if integrated auctions are not enabled, more incremental capacity could be offered in ad hoc open seasons with higher participation costs.

A summary of the additional costs is shown in **Table 6**. The additional annual costs are very small in relation to the illustrative potential net benefits, as described above.

48 The set up costs are given as €6 million pa for the first give years in the draft impact assessment on the NC CAM.

Table 6. Estimated annual costs of harmonisation

Item	€ million
Agree and consult on regulations	0.2
TSO preparatory work (advanced)	4
PRISMA platform	0.5
Shipper participation (advanced)	2
Total	**6.7**

Source: Frontier estimates

7.5 Conclusions on assessment of option

With regard to when incremental capacity is offered, our assessment indicates that the default should be a biennial offering at all IPs, unless the conditions we have proposed suggest that there is unlikely to be significant market demand.

With regard to how to offer incremental capacity, our assessment suggests that:

- it would be desirable to use require a cost-benefit analysis of incremental capacity to be undertaken at all IPs where it is to be offered before any market test. This would be done using the methodology being developed to meet the requirements of the Infrastructure Regulation and would provide estimates of the external benefits;
- TSOs and NRAs offering incremental capacity at IPs would have the choice between:
  - use of integrated auctions based on the design proposed in Section 6 designated as Option C2 for relatively simple projects involving only one pair of TSOs; or
  - an OS process based on the principles set out in Section 6 designated as Option D2 where choices and interactions that cannot be accommodated into an integrated auction are required and more than two TSOs are involved. Feedback from the current Fluxys-TENP OS using Option D3 can be used to review this conclusion.

We have provided an illustration of the order of magnitude of the net benefits by looking at the possible impact of bringing forward incremental capacity serving a group of countries in Eastern Europe which currently have high gas prices. On the basis of our assumptions, we are able to see net annual benefits of the order of €700 million, over 20 times the corresponding annual costs.

With regard to costs, our view is that these are relatively modest. New regulations and implementation of integrated auctions might cost of the order of €0.7 million, on an annual equivalent basis. Bringing forward offers of incremental capacity and bringing forward shipper participation in such offers might cost of the order of €6 million annually using a cost of capital of 4%.

8 Implications for Framework Guidelines and Codes

In this section we consider the implications of our proposals for:

- the gas transmission tariff harmonisation, including the framework guidelinees;
- the NC CAM for gas transmission systems; and
- the CMP decision of August 2012.

8.1 Implications for harmonised transmission tariffs

We have reviewed the draft Framework Guidelines on rules regarding harmonised transmission tariffs published in September 2012 to assess the implications of our proposals concerning incremental capacity.

It is clear from our work that harmonising arrangements for incremental capacity will require some significant changes that need to be made consistently across more than one network code and that these will require considerable debate in order to reach a consensus.. Following discussion with the Steering Group we have therefore provided a view on the implications for tariff harmonisation and then consider what points could be introduced into the Framework Guidelines at this relatively late stage in their development. Other elements could be introduced at a later stage as code modifications once full agreed – in other words after the code on harmonised transmission tariffs has been adopted.

We think that the main elements related to tariffs that require harmonisation are:

- the principles for design of the market test, as set out in Section 5. The parameters used in a test would be defined at national level by the relevant TSOs and NRAs;
- a requirement to make an assessment of the economic life of the asset and for regulatory depreciation to be based on the economic life and/or the profile of the economic value over time in order to align the depreciation charge to projected WTP – this measure would be designed to protect future consumers from the risk of asset stranding given the limited horizon over which shippers are willing to make commitments;
- enabling NRAs that wish to do so to start auctions of incremental capacity at a premium over reference prices in the event that the relevant TSOs have a floating tariff and NRAs wish to protect current holders of existing capacity from the higher cost of incremental

capacity, if released[49]. This proposal provides flexibility for NRAs – we are not recommending use of this approach or the alternative in which the floating price changes for all capacity holders; and

- with respect to the price payable to:
  - provide that the price payable for yearly capacity allocated in an earlier auction for a given year will be capped at the price payable in any subsequent release of incremental capacity for the same year – any reduction in revenue to the TSO would only arise from a reduction in the premium. Normal revenue recovery arrangements would continue to apply;
  - clarify that premia can arise in offers of incremental capacity using integrated auctions or using OS processes; and
  - enable TSOs to index any premia over the reserve price in order to maintain the value in real terms. This would only be possible if it was stated in the capacity contract - we do not propose a retrospective change.

The capping of the price paid for yearly capacity is intended to protect shippers from paying too much for existing capacity in an auction that does not offer incremental capacity (or in an auction which does offer incremental capacity but where it is not released because the market test is not met). For example, suppose an auction of existing capacity held in 2015 had a clearing price for yearly capacity in 2022 that was three price steps above the reserve price (suppose also that this reserve price was a floating tariff). If, in 2017, incremental capacity was released for the year 2022 and that this was allocated at the reserve price, without any premium, then as a result of the cap the winners in the 2015 auction would not have to pay any premium for the capacity that had been previously allocated. This protection could encourage shipper to bid more aggressively but we think that this is unlikely since that could never be certain that the cap would be triggered by a subsequent auction for the same yearly capacity.

The alternative approach is not to adopt a cap but to rely on the regularity of incremental capacity offerings to reduce any motivation to pay high premia for capacity beyond investment lead times.

In terms of changes that can be made in the short-term to the draft Framework Guidelines, we propose the following:

- a requirement that where a market test is used to decide on investment in incremental capacity, there should be full transparency on the inputs to the test, on the calculations to be performed and on the level of the threshold value that needs to be exceeded if the investment is to go forward; and

49 Such protection is not necessary where capacity is allocated at a fixed nominal price.

- the scope for ENTSOG to adapt the rules relating to price payable in order to facilitate investment in incremental capacity, including the potential to differentiate the effective reference price in offers of incremental capacity from that used where only unsold existing capacity is offered by adopting a minimum premium.

As noted above, other potential adjustments would await full agreement of the overall arrangements for incremental capacity and be made later using code modification procedures.

8.2 Implications for NC CAM

Our assessment of the implications for the NC CAM is based on the draft Commission Regulation made available to us by ACER in December 2012. We understand that this is the version that has been prepared for the comitology process.

The intention would be to broaden the scope of the NC CAM to cover incremental capacity offered in integrated auctions. We are unsure whether, from a legal point of view, the same NC could be used to harmonise the design of OS processes or whether this would need to go into a different NC or regulation.

The main changes required, other than the broadening of the scope, concern:

- TSO co-operation to identify incremental capacity projects for all IPs, unless certain conditions are met suggesting that it would not be of interest to shippers;
- obligations to offer incremental capacity biennially unless the conditions specified previously are met – either through an integrated auction or an OS process where more than two TSOs are involved;
- specification of the principles for conduct of an OS process, including use of a reserve price and price steps to allocate capacity in case of excess demand;
- amendment to regulations concerning yearly capacity auctions to permit yearly capacity to be offered for different quantities of existing and incremental capacity and to permit any existing unsold yearly capacity to be offered in an OS process for incremental capacity, where this is justified by the number of TSOs involved;
- minor amendments to the ascending clock methodology to make it compatible with the offers of incremental capacity; and
- amendments to the provisions on tariffs in line with the comments above on the framework guidelines.

More details with references to the chapters and articles of the NC CAM are shown in **Table 7**.

Table 7. Impact of incremental capacity proposals on NC CAM

Article	Implications
Recitals	New recital required referred to need for harmonised arrangements to decide on investment in incremental capacity and its allocation
Art 2 Scope	Scope to be amended to include offers of incremental capacity
Art 3 Definitions	New definitions needed for "incremental capacity" and "market test"
Chapter II on principles of cooperation	New article required to define obligations to develop investment projects to add different levels of incremental capacity and to offer such capacity biennially after publication of the EU TYNDP unless specified conditions are met
Chapter III on allocation of firm capacity	New article to be added concerning the basis for release of incremental capacity using the market test and the principles on which the market test is based. This article also deals with set aside of any percentage for short-term allocation.
Art 11 on yearly capacity auctions	Article to be amended to permit yearly capacity products to be offered for existing unsold capacity, as defined, and, in parallel ascending clock auctions, one or more levels of existing +incremental capacity with the relevant allocation results dependent on the market test for each successive increment. A further amendment would permit NRAs to extend the time horizon to be extended beyond the upcoming 15 years in the case of incremental capacity offers.
Art 17 on ascending clock algorithm	Article amended to permit auctions of incremental capacity to start at one or more price steps above the reserve price. Bids shall specify the total supply of capacity to which the bid relates in addition to the other points in 17.3
Art 19 on bundled capacity	Amended to say that all offers of incremental capacity shall be bundled
Art 26 on tariffs	Please see comments above on the tariff Framework Guidelines

Source: Frontier

Following discussion with the Steering Group, our proposal is that these changes should be made using a code modification procedure after the current draft is formally adopted. This permits changes in the NC CAM and the network code on tariffs (and potentially other codes) to be made in a harmonised manner once arrangements for incremental capacity have been debated and agreed.

8.3 Implications for the CMP Decision

We have reviewed the CMP decision of August 2012 in the context of the original Annex I to Gas Regulation 715/2009 and have concluded that our proposals would not require any amendment of the arrangements that will apply from October 2013 (or July 2016 in the case of the firm day-ahead use-it-or-lose-it mechanism).

There are however two areas where our proposals and CMP are likely to interact. These are:

- the obligation on TSOs to provide information on capacity sold, capacity utilisation and unsuccessful requests for capacity, combined with the obligation on the ACER to prepare a monitoring report on congestion at IPs will provide an essential input to any decision to permit a TSO not to offer incremental capacity on a biennial basis; and

- it will be important to distinguish between incremental capacity made available through physical investment and additional capacity made available through one of the CMP, such as oversubscription. In practice, we would expect additional capacity to be made available a few years ahead of the present whereas the investment lead time for incremental capacity is likely to be about 5 years or more. Additional capacity provision and offers of incremental capacity are therefore unlikely to overlap but we see no reason in principle why they should not do so.

In reviewing TSO proposals for oversubscription and buy-back arrangements, NRAs will need to ensure that the incentives do not have an adverse effect on TSOs willingness to offer incremental capacity.

9 Key design elements for an EU approach

In this short section we draw together the main elements of an EU-wide approach for harmonising the arrangements for incremental capacity that we propose. We also provide a tentative roadmap for their regulation and implementation.

9.1 Key design elements

We first set out the design elements we propose and then discuss to what extent they are can be implemented on a stand-alone basis or whether they must go together.

The key design elements are as follows:

- **design of market test**: we propose a set of principles to govern market tests used in demand-based investment, as set out in Section 5. However, we do not think, given the wide range of circumstances illustrated by the projects in Annexe 3, that it would make sense to define harmonised threshold ranges within which a positive result would trigger investment;
- **identification of incremental capacity options at IPs**: an obligation on TSOs to cooperate to identify options for incremental capacity at all IPs unless specified indicators suggest that there is unlikely to be demand for such capacity. Linked to the principles for the market test, we also suggest that TSOs should apply the cost-benefit methodology being developed in the context of the draft Infrastructure Regulation to incremental capacity projects that are not accorded PCI status;
- **when to offer incremental capacity**: we propose that, unless conditions are met that mean that there is unlikely to be significant demand for incremental capacity, TSOs should be required to offer such capacity on biennial basis at all IPs although the decision to invest could still depend on the results of a market test. The OGE case study in Annexe 3 illustrates how uncertainty about future offering of capacity can lead to unrealistically high demands. The first year in which capacity would be offered would correspond to the end of the investment lead time;
- **how to offer incremental capacity**: incremental capacity for which the investment decision was subject to a market test would be offered using one of the following methods:
  - **an integrated auction**, conforming to Option C2, in which yearly capacity is offered separately with different levels of supply in order

to provide reliable information on the demand at different price steps using the ascending clock methodology. A market test applied after the auction would determine if any incremental capacity would be released and thus which set of auction results for capacity allocation would be applicable. This method would be the default where no more than two TSOs were directly involved in the offer and the complexity of the offering was compatible with current NC CAM auction rules (e.g. no linking of bids at different IPs); or

- **an OS process**, conforming to Option D2, based on the principles set out in Section 6 and building on the extensive experience to date as illustrated by the projects in Annexe 3. This would be used for more complex projects where the number of project options and/or TSOs involved called for the flexibility available from an open season process – see text box on the following page. The market test included in the OS process would conform to the standard principles so that shippers would be asked to express their demand at a number of price steps.

- **tariff harmonisation**: in terms of the current framework guidelines, we suggest only minor changes to ensure market tests are transparent and to provide more flexibility with regard to the price payable. The need for more fundamental changes to the tariff harmonisation code would be considered in the context of the further development of the arrangements for incremental capacity so that a single consistent modification could be made across all relevant codes. Two more significant changes in relation to tariffs for consideration are:
  - a new rule that caps the price payable for capacity in a given year by existing capacity holders to the price set in an offer of incremental capacity for the same year; and
  - inclusion of a principle that depreciation rate should be based on an assessment of the economic life of the asset and/or the profile over time of its economic value in order to match better the depreciation charge to WTP. We recognise that these depreciation rates are sometimes determined by national legislation and may not be easy to change for particular projects. An alternative is to increase the price to reflect the additional risks.

Box: simple and complex projects

Where the nature of the incremental capacity project is simple, it will normally be possible to offer capacity using an integrated auction as described in Section 6. Examples of features that are likely to make a project more complex and more suited to an OS approach are:

- there are more than two TSOs directly involved;
- shippers want to link their bids for capacity at two or more different IPs;
- the perimeter of the project encompasses capacity at more than one IP and the market test needs to be based on demand at all relevant IPs; and
- the nature or location of the investment is contingent on an interim result of the OS process..

In terms of what elements go together, the principles for the market test could be implemented separately without action in any other area. Similarly, the requirements to identify and offer incremental capacity are separable, although without changes to the NC CAM any such offers would have to be made using OS processes. For this reason, we think the proposals on when and on how to offer incremental capacity go together.

We have also considered to what extent these proposals should be implemented as an EU-wide binding approach or as (non-binding) regional approach[50].

Anything which has to do with when incremental capacity is offered and the use of integrated auctions needs to be made binding. It would therefore make sense to implement using the NC CAM. Principles concerning the market test, reserve prices in auctions and the price payable will ultimately need to be part of the NC on tariffs and would therefore also be binding.

The elements where a non-binding, regional approach might be acceptable are those related to the preparation of cost benefit analysis on the basis of a common methodology to all incremental capacity projects and the principles for conducting an OS.

However, if an OS is to be an alternative basis for capacity allocation to an integrated auction and will also allocate any existing, unsold capacity, logic would suggest that the OS needs to be conducted on the basis of binding guidelines. Similarly, if the market test principles are to be binding, it would make sense to

50 Our terms of reference call on us to address this issue.

make the cost benefit analysis obligatory as this is an important input to the test. These binding guidelines would become part of the NC CAM.

9.3 Tentative roadmap

With regard to implementation, our thinking is that the instruments to be used where a binding approach is required would be the NC CAM and the NC on tariff harmonisation.

The NC CAM is currently in comitology and we think that it could come into force before the end of 2013. There is an 18 month period before it must apply and it is most likely to start at the beginning of a gas year. This implies implementation in October 2015.

Since the NC CAM has now started comitology and an impact assessment has already been carried out, we think that it is most likely that required changes would be introduced after adoption as a code modification request, following development and discussion of the CEER blueprint on incremental capacity. We assume that after this process has taken place in 2013, CEER would make a request to ACER and the Commission and these entities would draft the formal modification and prepare an official Impact Assessment during 2014. Comitology on the modification might start in 2015 and the modifications be applied in 2016.

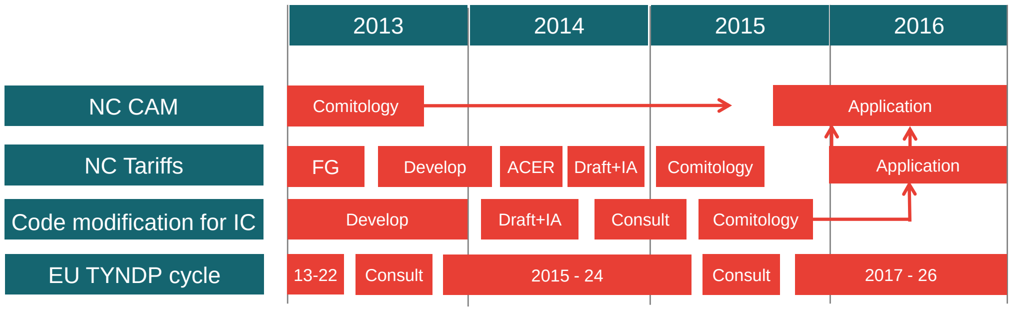
It is also important to note that the biennial EU TYNDP process will continue in the background as this will be critical to the identification of incremental capacity projects, as well IPs where there is no requirement to offer incremental capacity. The second formal EU TYNDP for 2013-2022 will be published in February of 2013 as a draft for consultation and the third EU TYNDP will be available in early 2015. This could be used as the basis for identification of IPs at which incremental capacity would have to be offered.

Some elements of our proposals would be regulated by the NC on tariff harmonisation. The Framework Guidelines have already been the subject of a consultation and ACER will soon publish the final version of the Guidelines. For this reason we have proposed only minor changes to the guidelines at this late stage. Our understanding is that the NC will be developed by ENTSOG during 2013 and early 2014 and that, following an ACER opinion, a draft regulation might emerge from comitology in the course of 2015 with application during 2016. Any more fundamental changes agreed during the detailed development of the arrangements for incremental capacity could then be made through the same code modification procedure.

On this basis our tentative roadmap would therefore lead to the first offers of incremental capacity in the course of 2016.

These stages are shown diagrammatically in **Figure 12**.

Figure 12. Tentative road map for implementation of incremental capacity measures



Source: Frontier

10 Applicability to new capacity

We now consider the extent to which our proposals could be applied to new capacity as well as to incremental capacity. As noted in Section 1, we consider new capacity to be capacity between MSs that are not already interconnected i.e. capacity at a new IP. This is because any new physical pipeline between MSs that are already connected will provide incremental capacity as part of a VIP.

We consider in turn:

- the principles concerning market tests;
- the proposals with regard when to offer incremental capacity; and
- the proposals concerning how to offer incremental capacity.

Once new capacity has been built, it will become an existing IP and the normal NC CAM and CMP rules will apply.

10.1 Market test and new capacity

We think that the principles governing the design of the market test are valid for both incremental and new capacity. However, we recognise that, in the absence of any information from allocation of existing capacity, it is likely to be more difficult to assess over what horizon shippers are willing to make commitments.

New capacity is also more likely to be associated with external benefits and these will need to be estimated and taken into account explicitly in the design of the test.

10.2 When to offer new capacity

Our thinking concerning regular offering of incremental capacity unless certain conditions are satisfied cannot be directly applied to new capacity – this is because there is no data on sales of existing capacity or scenarios in which congestion could be assessed.

We think that for new capacity, NRA and TSOs need to keep the case for interconnection under review and consult with shippers about potential requirements in the context of the regional TYNDPs prepared under the GRIs.

10.3 How to offer new capacity

The concept of an integrated auction does not really apply to new capacity as there is no existing capacity that can be offered. However, there is no reason why the same methodology and auction platform could not be used for new capacity. Capacity at a new IP could also be offered at the same time as the yearly capacity auctions for existing IPs, with its own reserve price (for a new entry/exit point there would be no existing reference tariff) . Clearly, capacity would only be allocated if the market test was satisfied unless the decision to invest had already been made.

OS processes are also equally applicable to new capacity and offer the option of a non-binding phase that could be useful to collect information that may inform the decision on what to offer in the binding phase. OS can also handle complex situations with different options and the possibility of award of new capacity being linked to incremental capacity at another IP.

Annexe 1: Glossary

Abbreviation	Meaning
ACER	Agency for the Cooperation of European Regulators
CEER	Council of European Energy Regulators
CMP	Congestion management procedures
ENTSOG	European Network of Transmission System Operators for Gas
EEPR	European Energy Programme for Recovery
FID	Final Investment Decision
GGPOS	Guidelines of Good Practice for Open Seasons
GB	Great Britain
GRI	Gas Regional Initiative
IP	Interconnection point
ITO	Independent Transmission Operator
LNG	Liquid Natural Gas
LRMC	Long run marginal cost
MS	Member States
NC	Network Code
OS	Open season
PCI	Projects of common interest
TSO	Transmission System Operator
TYNDP	Ten year network development plan
UIOLI	Use it or lose it
VIP	Virtual Interconnection point
WTP	Willingness to pay

Annexe 1: Glossary

Annexe 2: Description of integrated auctions in Great Britain

This annex sets out our understanding of the approved National Grid (NG) methodology for the allocation of existing entry capacity and, at the same time, for reaching decisions on any incremental capacity release and its allocation. The methodology is implemented using an integrated static auction i.e. there are no sequential rounds at increasing prices as in the proposed NC CAM auctions.

These auctions concern entry capacity to the GB market area from offshore production, LNG facilities and interconnectors. They are not sales of capacity at IPs between hubs.

The reserve prices and incremental prices used in the integrated auction are derived from NG's approved tariff methodology so we begin with an explanation of the approach to setting entry and exit transmission tariffs and then describe the approach to incremental capacity.

The annex is structured as follows:

- objectives of GB's transmission charging;
- overview of relationship between charges and allowed revenues;
- methodology for NTS entry and exit capacity charging; and
- allocation of NTS entry an and release of incremental capacity. We also briefly mention allocation of exit capacity.

The description is based on the methodologies approved by Ofgem for application in 2012 and takes no account of adjustments that may be made in the course of the next price control review known as RIIO-T1. Capacity is priced in pence per kWh per day denoted as p/kWh/d

Objectives of transmission charging in GB

NG is the owner and the operator of the National Transmission System ("NTS") for natural gas in Great Britain. Its Licence Obligations require the charging methodology to:

- reflect the costs incurred by National Grid where charges are not determined by auctions; and, subject to this principal consideration;
- facilitate competition between gas shippers and between gas suppliers; and
- take account of developments in the transportation business;

- where prices are established by auction and where reserve prices are applied that these are set at a level best calculated:
  - to promote efficiency and avoid undue preference in the supply of transportation services; and
  - to promote competition between gas suppliers and shippers.

Overview of relationship between charges and allowed revenues

NG's charges are regulated through a system of allowed revenues set by Ofgem for a number of years in real terms. NG is permitted to earn these revenues in return for making available baseline entry and baseline exit capacity on the NTS. There are currently 23 entry points and more than 220 exit points.

NG's activities as Transmission Owner (TO) and as System Operator (SO) are separately defined. Each one has its own allowed revenues[51]. The majority of the allowed revenues relate to the TO business. In addition to baseline revenue, the agreement with Ofgem provides for "revenue drivers" that are used to increase the allowed revenue in response to demand for incremental capacity under if an economic test is met. We describe the implications in greater detail later in this annex.

NG's transportation charges are set with the aim of recovering allowed revenues for the TO and SO businesses. The charges applied are as follows:

- The **NTS TO allowed revenue** is collected by entry and exit capacity charges, which vary according to location:
  - Charges for sale of entry and exit capacity are each set with the aim of recovering 50% of the total allowed revenues;
  - Entry capacity sales are made by auctions and an entry commodity charge may also be levied on NTS entry flows if the entry capacity auction revenue is expected to under-recover target revenue of 50%;.
  - Exit capacity sales are made at fixed prices for both firm and interruptible capacity.[52]
- The **NTS SO allowed revenue** is largely collected by means of a uniform commodity entry and exit charge. The commodity charge is set to recover

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51 The SO revenue includes provision for an incentive scheme linked to performance.

52 The methodology for allocating firm exit capacity was changed Oct 2012. Up this date allocation was done administratively for all capacity but thereafter it is by a combination of an application process and short-term auctions.

the bulk of SO allowed revenues. The SO commodity charge from 1st October 2012 is 0.0229 p/kWh for flow at each entry and exit point.

Charges are allowed to change on 1 April and 1 October each year, with changes at other times of the year permitted only in exceptional circumstances and with the agreement of Ofgem.

NG uses a methodology based on long run marginal cost (LRMC) principles to set entry capacity auction reserve prices and TO exit capacity charges.

In the next section, we describe the approach NG uses to sets charges for entry and exit capacity based on estimates of the LRMC for each entry and exit node or point. We then explain the integrated auctions used to allocate the entry capacity and to decide on release and allocation of incremental capacity.

Derivation of NTS entry and exit capacity charges and the commodity charge

NG determines the entry and exit capacity charges using the NTS **Transportation Model.** The model applies a methodology that broadly follows the principles of LRMC based pricing, with adjustments to meet target revenue requirements.

For entry capacity, the charges are used to set the reserve prices for the annual auctions of long-term capacity[53] at each entry point. By contrast, for exit capacity, the charges set the fixed price for annual capacity at each exit point[54].

To derive the charges NG uses the **Transport Model,** which is identical for deriving entry capacity reserve prices and exit capacity charges, and a **Tariff Model**. The tariff model contains some common elements for deriving entry and exit capacity charges, but it varies in the detail. In the following sub-sections, we describe the models and the calculations used to derive entry capacity reserve prices and exit capacity prices.

The Transport Model

The transport model calculates the long-run marginal costs (LRMC) of transporting gas from each system entry point to a "reference node" and from the "reference node" to each exit point. This LRMC is an estimate of the marginal cost of investment in the transmission system that would be required as a consequence of a permanent increase in capacity at each entry or exit point on the transmission system.

53 In the form of 60 quarterly products.

54 Since October 2012 the charges are also used as the basis for reserve prices in the short-term auctions of exit capacity.

To derive the LRMC at each entry and exit point, a common investment cost for new NTS pipelines and compression is used. This is expressed in terms of £/GWhkm and is known as the *expansion constant*. The cost can be applied to the rate of change in the gas flow distance on the network (increases or decreases), measured in km, for a marginal increase in gas injection at each entry point or increase in gas withdrawal at each exit point on the system relative to a reference node.

To derive the rate at which the flow distance changes for a marginal change to an injection or withdrawal, the transport model starts with a base case network and set of flows on the system. The marginal changes are applied to this network[55]. The base case network uses the following information:

- Supply and demand (GWh):
  - forecast of supply per entry point, each capped at its obligated entry capacity[56]; and
  - forecast of 1-in-20 peak day demand[57] at each exit point by distribution networks and direct connections.
- Transmission pipeline length between each node (km) for:
  - existing pipelines; and
  - newly built pipelines that are expected to be in operation at the beginning of the respective gas year from NG's most recent Ten Year Statement;
- Identification of a reference node (which is Peterborough in the East of England)[58].

The following merit order for supply is used when balancing supply and demand for the base case flow model:

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55 The marginal changes are conceptual. In practice the values are available as shadow prices of the flow gradients in the transport model optimisation.

56 Obligated capacity is the amount of system entry capacity which National Grid is required to make available to Users pursuant to the Licence.

57 The 1-in-20 peak day demand is the peak day demand that, in a long series of winters, with connected load being held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters.

58 NG notes that the choice of the reference node does not affect the final tariffs because the absolute relativities between nodes are maintained when the marginal costs at entry and exit points are adjusted up or down to meet revenue targets. This statement is correct when calculating the marginal flow distances. However, later we discuss whether this statement holds when the tariff model is applied.

- beach supplies;
- interconnectors;
- long range storage;
- LNG imports;
- mid-range storage; and
- short-range storage.

Given the set of base case supply and demand parameters, an optimisation model derives the minimum total network flow distance (in GWhkms). In other words, the model calculates the minimum distances travelled by gas given the pattern of entry and exit flows, assuming that every network section has sufficient capacity.

The transport model calculates the marginal flow distance required to get to the reference node for:

- an incremental injection at each entry point; and
- an incremental withdrawal at each exit point.

The Nodal Marginal Distances are expressed in kms - NG refers to these distances as marginal costs.

The marginal distance for an entry or exit point may be positive or negative, depending on whether the marginal injection or withdrawal tends to reinforce the direction of flow on the base case network or offset the direction of flow on the base case network (i.e. creating a marginal benefit or avoided cost). Note that at any point the marginal cost of demand is equal and opposite to the marginal cost for supply.

In determining the marginal distance for each entry and exit point, the transport model assumes that all elements of the network are continuously variable in size and that there are no sunk costs. The model also abstracts from the physical reality of gas flows by assuming that flow costs are linear with distance.

The Tariff Model

The tariff model is applied separately in calculating entry capacity reserve prices and calculating exit capacity charges. In both cases the tariff model adjusts the marginal distances derived by the transport model to meet the target revenue requirement and to eliminate any negative marginal costs.

The precise way in which the adjustment is applied differs between entry and exit. However, the following three elements of the tariff model are common to both and are explained below:

- **Initial Nodal Marginal Distances.** The initial nodal marginal distance for supply point i (in km) is set equal to the marginal distance to the reference node from supply point i (km).[59] Similarly, the initial nodal marginal distance for demand point j (in km) is set equal to the marginal distance to the reference node from demand point j (km). The tariff model then adjusts the initial nodal marginal distances with the aim of meeting target revenues, as described in the next two subsections.

- **Expansion Constant.** The adjusted marginal distances are multiplied by the expansion constant (£/GWh/day/km) to convert them into unit costs (£/GWh/day) for entry and exit capacity. The expansion constant represents the capital cost of the transmission infrastructure investment necessary to transport up to 1 GWh/day over 1 km in a pipeline with a pressure of 85 bars.

  The capital cost is derived by estimating the cost of a 100km stretch of pipeline, including compression. The cost is estimated for three pipeline diameters, 900mm, 1050mm and 1200mm and the result is averaged.

  Costs are based on manufacturers' prices and historic costs inflated to present values. A 15 per cent allowance is added to account for engineering and project planning costs.

  The amount of flow able to be accommodated through each diameter pipe depends on the amount of compression. The amount of compression required for the 100km stretch of pipe is optimised to minimise the unit cost of expansion (£/GWh/day/km) for each size of pipe.

  The 2012/13 value of the expansion constant is £2437.

- **Annuity factor**. The unit cost is converted into a daily capacity charge by multiplying by the annuitisation factor of 0.10272 and then dividing by the number of days in the year. The annuitisation factor was agreed in Ofgem's Transmission Price Control Review for 2007 - 12 and assumes a 45 year asset life, an allowed real rate of return of 6.25 per cent on capital expenditure and an annual opex allowance of 1 per cent of capital expenditure. The factor is derived from the cash flows flowing from a unit investment added to the regulatory asset value.

The tariff model for determining NTS entry capacity charges

Entry charges (annual reserve prices) are determined by the following steps:

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59 The methodology statement uses the term supply to mean entry point and demand to mean exit point.

- calculation of the Initial Nodal Marginal Distances for each entry points on the NTS;
- adjusting the Initial Nodal Marginal distances for entry and exit points to approximate the 50:50 revenue split and to remove negative values - the adjusted values are the Nodal Marginal Distances (i.e. no longer initial); and
- conversion of the Nodal Marginal Distances to entry prices

Deriving Initial Nodal Marginal Distances for entry points

National Grid starts with the base case transport model, as described above. It then uses the model to calculate the Initial Nodal Marginal Distance for each supply or entry point in turn.

The supply flow at the supply point in question is adjusted to be equal to the baseline obligated entry capacity. Other supply flows are adjusted up or down to balance the network such that aggregate supply flows equal the peak 1-in-20 demand.

The merit order applied in adjusting the other supply points is based on the distance from each other supply point to the supply point in question:

- if the base case flow of a supply point is adjusted upwards to equal the baseline obligated entry capacity, flows at other supply points are reduced, starting with the furthest supply point from the supply point in question; and
- if the base case flow of a supply point is adjusted downwards to equal the baseline obligated entry capacity, flows at other supply points are increased, starting with the nearest supply point to the supply point in question.

The process is repeated for each supply point in turn.

Entry-exit price adjustment

In a first step, the Initial Nodal Marginal Distances (Initial NMk) are adjusted to obtain the 50:50 revenue split between entry and exit charges and to remove the negative marginal distances.

This is done by calculating a uniform Adjustment Factor (AF), which is added to each Initial Nodal Marginal Distance at all entry points and subtracted from each Initial Nodal Marginal Distance at all exit points to derive revised marginal distances for each supply (entry) and demand (exit) point. For the purpose of calculating AF, the adjusted Initial Nodal Marginal Distances are collared to zero. The adjustment factor (AF) is calculated using a solver such that the average revised marginal distances for supply and demand are identical. This is shown in the formula below.

$$\sum_{Si=1}^{n_S}\left(\frac{Max\left[0, InitialNMkm_{x,Si} + AF_x\right]}{n_S}\right) = \sum_{Dj=1}^{n_D}\left(\frac{Max\left[0, InitialNMkm_{x,Dj} - AF_x\right]}{n_D}\right)$$

The resultant Nodal Marginal Distance for each supply point and each demand point is therefore the collared[60] Initial Nodal Marginal Distance plus/minus the adjustment factor for each supply point and demand point, respectively. Any negative values are set to 0.0001 p/kWh/d.

Entry capacity reserve prices for the sale of baseline capacity

Entry capacity reserve prices (p/kWh/day) are calculated on the basis of the Nodal Marginal Distances (km). These distances are converted to annualised capital costs by multiplying by the expansion constant (£/GWh/day/km) and the annuitisation factor (AnF). They are also adjusted to recognise different calorific values of gas at different entry points and converted into p/kWh/day. These reserve prices are valid for the sale of obligated capacity at each entry point.

$$EntryPrice_{Si} = Max\left[0.0001, \left(\frac{NMkm_{0,Si} \times AnF \times EC \times 100}{10^6 \times 365} \times \frac{39}{CV_{Si}}\right)_{4dp}\right]$$

The application of this approach to derive prices for the release of incremental capacity is described later in this annex.

The tariff model for determining NTS exit capacity charges

The total revenue to be recovered from charges for firm and interruptible exit capacity is equal to 50 per cent of TO allowed revenues.

An annual target revenue ($TOExRF_t$) is set for firm exit capacity charges.

Capacity charges at all exit points for firm baseline exit capacity and incremental exit capacity are set simultaneously in the tariff model. The Initial Nodal Marginal Distances derived from the base case transport model are adjusted to meet the revenue target, $TOExRF_t$. A single Revenue Adjustment Factor (RAF) is calculated and added to all Initial Nodal Marginal Distances at exit points to derive revised marginal distances. Prior to October 2012, revenue charges for

60 By collared we mean that it is subject to the constraint that it cannot be less than a value, in this case zero.

incremental capacity were treated as SO revenue but in future will be treated as TO revenue.

The RAF is set such that the total revenue to be recovered from baseline firm (TO) exit charges equals the annual target revenue, with the exit charges constrained to be 0.0001 p/kWh/day or greater. As part of the revenue calculation, revised marginal distances are multiplied by the annuitisation factor and the expansion constant. No adjustment is made for calorific values at exit.

$$ExitRev_{t,Dj} = Max\left[(0.0001/100)\times ExitCap_{Dj}\times 365, \frac{(InitialNMkm_{Dj}+RAF)\times ExitCap_{Dj}\times AnF\times EC}{10^6}\right]$$

$$ExitRev_{t,Dj,inc} = Max\left[(0.0001/100)\times ExitCap_{Dj,inc}\times 365, \frac{(InitialNMkm_{Dj}+RAF)\times ExitCap_{Dj,inc}\times AnF\times EC}{10^6}\right]$$

$$\sum_{Dj=1}^{n_D}(ExitRev_{t,Dj}) - \sum_{Dj=1}^{n_D}(Exit\,Re\,v_{t,Dj,inc}) = TOExRF_t$$

$$SOExRF_t = \sum_{Dj=1}^{n_D}(ExitRev_{t,Dj,inc})$$

Nodal exit capacity charges (p/kWh/day) are then set using the same Initial Nodal Marginal distances plus the adjustment factor, multiplied by the expansion constant (£/GWhkm) and the annuity factor, and finally converted into a daily charge. The minimum exit capacity charge is 0.0001 p/kWh/day.

$$ExitPrice_{Dj} = Max\left[0.0001, \left(\frac{(InitialNMkm_{Dj}+RAF)\times AnF\times EC\times 100}{10^6\times 365}\right)_{4dp}\right]$$

Finally, zonal exit capacity charges (p/kWh/day) are calculated as the capacity weighted average of the nodal exit capacity charges within the zone, k.

$$ZonalExitPrice_k = \left(\frac{\sum_{Dj=1}^{n_k}(ExitPrice_{Dj,k}\times ExitCap_{Dj,k})}{\sum_{Dj=1}^{n_k} ExitCap_{Dj,k}}\right)_{4dp}$$

NTS commodity charges

SO and TO commodity charges are levied on gas flows allocated to shippers at entry and exit points, other than storage.

The principal commodity charges are as follow:

- **NTS TO entry commodity charge** – levied when the TO entry capacity auctions are forecast to generate under 50% of the overall allowed revenues e.g. because shippers no longer want capacity at a certain entry point or choose to buy it at zero cost on the day or on an interruptible basis. NG forecasts revenues following the MSEC auction and may then determine the TO entry commodity charge for the following 6 months when charges are again reviewed.

- **NTS SO entry and exit commodity charges** – levied on both entry and exit gas flows in order to recover target revenues for the SO.

The commodity charge thus serve as the primary mechanism for making good any shortfall in TO revenues.

NTS entry capacity allocation – the integrated auction

This section explains the allocation mechanism for NTS baseline entry capacity and for deciding whether to release and thus allocate incremental capacity. It also briefly describes the allocation process for NTS exit capacity.

Auctions for allocating NTS entry capacity

Currently, NG uses five auctions with different time frames for selling available[61] NTS entry capacity to the market, as briefly summarised below. The quarterly system entry capacity (QSEC) auctions[62], held annually, offer both baseline obligated entry capacity **and** incremental entry capacity. This is an integrated auction in the sense used in this report.

NG can also hold ad hoc QSEC auctions that solely offer incremental capacity at new entry points.

Baseline obligated entry capacity levels are fixed by NG's Licence for each individual entry point. In addition, NG releases incremental entry capacity if NG determines that users' demand for entry capacity, as revealed by an information gathering process and an economic test requires this increase. This then become incremental obligated capacity.

In the auction, bids for capacity are requested at 20 price steps above the reserve price each of which corresponds to the LRMC of a certain amount of incremental capacity. The derivation of these price steps is described below.

If the aggregate quantity specified in valid bids at the reserve price is less than or equal to the available quantity of baseline obligated entry capacity at any aggregate system entry point then capacity will be allocated to satisfy all requests in full.

However, if the demand for entry capacity exceeds the available capacity at the entry point in a sufficient number of quarters in the future, NG would determine

61 Available is used here to mean not already sold or booked.

62 See below for a description of the QSEC auctions.

the present value of the revenue from bids for incremental obligated entry capacity which would be accepted if the given quantity of incremental obligated entry capacity was released. This is done for up to 32 quarters from the release date. Two outcomes are possible:

- If this PV equals at least 50 per cent of the estimated project value[63], NG would make a proposal to release that quantity of incremental entry capacity as incremental obligated entry capacity under the terms of its Licence; or
- if the PV is less than 50% then the available baseline capacity is allocated at the price at which aggregate demand is less than or equal to this capacity – in other words there is no obligation to release incremental capacity[64].

The price payable is the actual clearing price calculated in the auction, without any form of indexation. Any shortfalls on entry capacity revenue due to changes in future shipper demand or due to inflation are recovered through the entry commodity charge.

NG's License requires it to offer 90 per cent of baseline obligated entry capacity (plus any unsold incremental entry capacity) at each entry point through the QSEC auctions, which are held annually for capacity to flow gas for each quarter from Years 2 to 16 years into the future (where Year 1 is the current gas year). Any remaining entry capacity is offered for sale through the subsequent auctions with shorter time-scales.

The standard investment lead time for offering incremental capacity is 42 months. There are incentives on NG to reduce this lead time. Assuming the standard lead time is taken, then the 32 month (8 year) horizon used in the economic test may be less than the overall period over which baseline capacity is offered.

In the event that NG is unable to deliver obligated incremental capacity it must buy it back.

In addition to the QSEC auctions, NG also releases unsold entry capacity in the following auctions, none of which offer incremental capacity:

- annual auctions of monthly firm capacity;
- rolling monthly auctions for firm capacity in the following month;

63 The estimated project value for an entry point follows a similar LRMC approach to that applied in setting the reserve prices for entry auctions.

64 In this situation NG can decide to release capacity above obligation, for some or all of the quarters in question, as non-obligated capacity.

- daily auctions for firm capacity on the following day; and
- daily auctions of interruptible capacity.

To secure sufficient revenues from entry capacity allocation NG sets reserve prices for the auctions. NG derives the reserve prices for the QSEC auctions for each ASEP using its transportation model, which applies a methodology that broadly follows the principles of LRMC based pricing, with adjustments aimed at meeting target revenues. To reflect differences in marginal costs, reserve prices are derived individually for each ASEP. We explain the methodology that NG uses to derive reserve prices in the next section.

Prices for the sale of incremental entry capacity or allocation of existing capacity

For the sale of incremental capacity, prices (Incremental Entry Capacity Step Prices) based on the long run incremental cost of providing the additional capacity is calculated. Prices are calculated for up to 20 levels of incremental capacity each equal to a multiple of 2.5% of baseline capacity. The maximum incremental capacity offered is thus 50% of baseline capacity.

NG derives long-run incremental costs at a supply point as the difference between the adjusted Nodal Marginal Distances for each incremental capacity level at the supply point and the adjusted Nodal Marginal Distances for the obligated capacity level at the supply point, as described previously.

The resulting differences between adjusted Nodal Marginal Distances are converted into unit incremental costs (p/kWh/day) by applying the expansion constant, the annuitisation factor and the adjustment factor for calorific value and then converting into a daily charge. The process is the same as that described previously for reserve prices.

Using NG's LRMC model for each incremental capacity level in this manner produces a set of prices which increase monotonically as capacity increases, except in the case of a new entry point. The prices can thus be used to allocate existing capacity at a premium (where the economic test is not met) or as a trigger to release incremental capacity (where the economic test is met).

These incremental prices are finally added to the baseline entry capacity reserve price for each of the up to 20 incremental levels of capacity at each entry point.

More precisely, the following steps are taken:

- First, **Nodal Incremental Distances** (km) are determined as the difference between the nodal marginal distance at the incremental level and the nodal marginal distance at the obligated capacity level for each ASEP.

$$NIkm_{x,EntryPoint} = NMkm_{x,EntryPoint} - NMkm_{Obligated,\ EntryPoint}$$

The nodal incremental distances for the incremental level are calculated by reapplying the transport model and recalculating the adjustment factors for comparison with those applicable to the obligated capacity level.

- Second, the nodal incremental distances are converted to **Entry Capacity Step Prices**. The nodal incremental distance is multiplied by the expansion constant, the annuitisation factor and a conversion rate for calorific value and converted to p/kWh/day. The result is added to the obligated capacity reserve price to get the initial incremental step price.

$$Price_{Obligated,EntryPoint} = Max\left[0.0001, \left(\frac{NMkm_{Obligated,EntryPoint} \times AnF \times EC \times 100}{10^6 \times 365} \times \frac{39}{CV_{EntryPoint}}\right)_{4dp}\right]$$

$$InitialPrice_{x,EntryPoint} = Price_{Obligated,EntryPoint} + \left(\frac{NIkm_{x,EntryPoint} \times AnF \times EC \times 100}{10^6 \times 365} \times \frac{39}{CV_{EntryPoint}}\right)_{4dp}$$

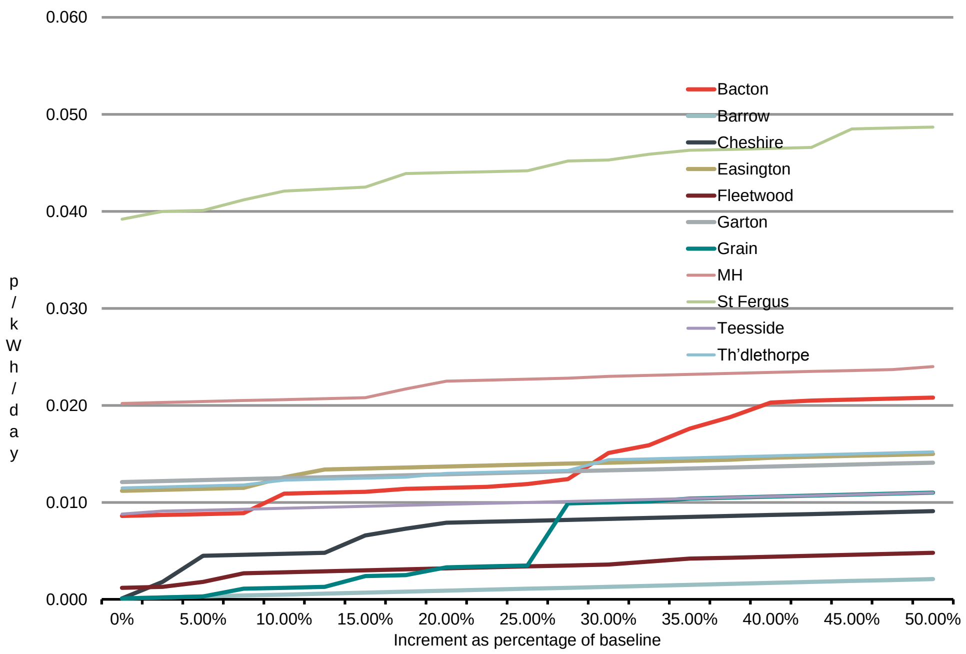
- While the above calculation is valid for existing pipelines, the derivation of initial incremental price steps for **New Entry Points** is increased to take into account the estimated connection cost of the new entry point

- Finally, incremental step prices for incremental capacity at an existing entry point are forced to be monotonically increasing[65], with a price difference between incremental capacity steps of at least 0.0001 p/kWh/day. The monotonic price schedule is required to ensure that the incremental capacity allocation can be solved with a unique clearing price.

Figure 13 shows step prices for a number of entry points in 2012. The incremental capacity as a percentage of the baseline capacity is shown on the x axis and price steps on the y axis.

65 Price at new entry points may be monotonically decreasing since there is no existing capacity to be allocated.

Figure 13. Incremental price steps for a range of entry points in p/kWh/d



Source: NG letter to Ofgem, Notice of Revised NTS Entry Capacity Reserve and Step Prices, March 2012

The economic or market test

In determining whether there has been sufficient user commitment to release incremental capacity, National Grid compares the net present value of the revenue from bids for incremental obligated entry capacity which would be accepted if the given quantity of incremental obligated entry capacity was released to the estimated project value of releasing the incremental capacity. This is done for a period of up to 32 months (8 years). If this NPV equals at least 50 per cent of the estimated project value, NG would make a proposal to release that quantity of incremental entry capacity.

The discount rate used is the real pre-tax WACC plus projected inflation.

National Grid calculates the project value as the initial incremental step price multiplied by the size of the incremental step, converted into a capital amount (i.e. by turning the daily price into an annual price and dividing by the annuity factor).

The test is first applied to the highest level price step for which aggregate demand is greater than or equal to the incremental capacity offered in any quarter. The relevant price steps in each of the subsequent 32 quarters then correspond to this level of aggregate demand or the next lowest level if there is no corresponding demand. This may be at lower price step. If the economic test fails for this incremental capacity, then the test is re-applied at the next price step in the first quarter at which aggregate demand is greater than, or equal to, the incremental capacity offered. This continues in iterative fashion until the test is met and an amount of incremental capacity is released or it becomes clear that there is no case for releasing any such capacity.

Once the amount of capacity to be made available has been determined, the allocation is made to those bidders for which aggregate demand is less than or equal to capacity made available at the corresponding price step.

An example of this process for a single level of incremental capacity is shown at the end of this section. This example is taken form National Grid's methodology statement for release of incremental capacity. Points to note about the example are:

- each level of incremental capacity is associated with a price step;
- the obligated baseline volume is 100 GWh/day and the test is for release of an additional 30 GWh/day from Q3 – this is the first price step/quarter combination in which aggregate demand is equal to the incremental capacity offered[66];
- the clearing price in each quarter then becomes the lowest price at which aggregate demand is less than or equal to 130 GWh; and
- the incremental revenue used in the economic test for each quarter is the clearing price times the volume of additional capacity sold.

We have added some extra graphics to highlight the aggregate demand and price steps to be considered.

Implications for NG's allowed revenues

If obligated incremental capacity is released, NG's allowed revenues are increased for by a revenue driver for a period of 5 years. The revenue drivers, annual amounts based on the capacity is released, are calculated in a separate Network Investment Model. After the 5 year period, the revenue drivers are removed and the replaced by RAV and allowed opex adjustments. These arrangements are due to change in the new RIIO-T1 price controls to be implemented from April 2013.

66 Note that in Q3 there is demand for 140 GWh at P_1 but there is only 110 GWh/d available for release at this price step.

Administered allocation of exit capacity

The allocation mechanism for NTS exit capacity was changed for capacity made available from 1st October 2012. Prior to this data exit capacity as allocated allocated under transitional arrangements. Annual capacity is now allocated administratively and daily capacity by auction. Since annual exit capacity is released in advance, the new arrangements have been used since 2009.

Annexe 2: Description of integrated auctions in Great Britain

This example is provided as an indication of how the methodology to release incremental entry capacity is applied. It should not be taken as being indicative of actual step prices, project values, or the ease with which release of capacity may be triggered.

Assume:

1. for simplicity there are only 5 price steps
2. the obligated volume is 100GWh/d
3. Q1 is April 2013

National Grid publishes the following Price Schedule to apply in a QSEC auction.

Available (GWh)	Price Label	Price (p/kWh/d)	Estimated project Value (£m)
150	P_5	0.06	20
140	P_4	0.05	16
130	P_3	0.04	12
120	P_2	0.03	8
110	P_1	0.02	4
100	P_0	0.01	0

Clearing prices for capacity of 130 GWh/d shown circled in

Assume the following bids are obtained through the auction:

Supply			Demand																	
Available (GWh)	Price Label	Price (p/kWh/day)	Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12	Q13	Q14	Q15	Q16	...	Q32
150	P_5	0.06	100	100	120	120	110	100	100	100	100	100	100	100	100	100	100	100	...	100
140	P_4	0.05	100	100	120	120	110	100	100	100	100	100	120	100	100	100	100	100	...	100
130	P_3	0.04	100	100	130	130	120	100	130	130	100	100	130	125	100	100	110	110	...	100
120	P_2	0.03	100	100	135	135	120	100	135	131	110	100	132	125	100	100	120	120	...	100
110	P_1	0.02	100	100	140	135	130	100	140	140	120	100	134	125	100	100	120	120	...	100
100	P_0	0.01	100	100	145	140	131	100	140	140	120	100	135	130	100	100	120	120	...	100

The NPV test is shown below. Since the present value of the incremental revenue is equal to half the project value, the capacity is released

			Oct-12	Jan-13	Apr-13	Jul-13	Oct-13	Jan-14	Apr-14	Jul-14	Oct-14	Jan-15	Apr-15	Jul-15	Oct-15	Jan-16	Apr-16	Jul-16		Jul-20
			Q1	**Q2**	**Q3**	**Q4**	**Q5**	**Q6**	**Q7**	**Q8**	**Q9**	**Q10**	**Q11**	**Q12**	**Q13**	**Q14**	**Q15**	**Q16**		**Q32**
Incremental Capacity to release	**GWh**	**(a)**	0	0	30	30	30	0	30	30	20	0	30	30	0	0	20	20		0
Clearing Price	**p/kWh/d**	**(b)**	0.01	0.01	0.04	0.04	0.02	0.01	0.04	0.04	0.01	0.01	0.04	0.01	0.01	0.01	0.01	0.01		0.01
Days per quarter	**day**	**(c)**	92	90	91	92	92	90	91	92	92	90	91	92	92	91	91	92		91
Incremental Revenue	**£m**	**(a)*(b)*(c)/100**	0.00	0.00	1.09	1.10	0.55	0.00	1.09	1.10	0.18	0.00	1.09	0.28	0.00	0.00	0.18	0.18		0.00
NPV Test	**£m**	**50% Project Value**	**6**																	
NPV of Revenue	**£m**	**2.01%**	**6.0**																	

Annexe 2: Description of integrated auctions in Great Britain

Annexe 3: Illustrative incremental capacity projects

We present below five short case studies of the following projects agreed with the Steering Group:

- France - Spain IP expansion 2013
- France – Spain IP expansion 2015
- Germany – Poland IP expansion (Lasow)
- Open Grid Europe reinforcement
- Austria - Slovenia IP expansion.

France - Spain IP expansion 2013

The project

Open Season 2013 process refers to the capacity to be developed at Larrau and Biriatou, two physical IPs between France and Spain, as well as the incremental capacity between GRTgaz South and the TIFG balancing zones in France. Larrau and Biriatou are treated as one single commercial point for allocation purposes.

Taking both points together, the existing capacity of 115 GWh/day ES>FR will be increased to 225 GWh/day. For FR>ES it will increase from 100 to 225 GWh/day. Only 80% of these capacities were offered in the open season.

The promoters were GRTgaz, TIGF, ENAGAS, Naturgas Energia and the total project cost was €1887 million, of which €98 million was financed by the EEPR. 30% of the costs were to be incurred in France and 70% in Spain.

With regard to benefits, the development of interconnections between France and Spain aims to step up the integration of Iberian, French and North-European markets. The incremental capacity will improve the security of supply for France and the Iberian Peninsula and develop the French gas market in the southern part of the country.

The process

The network development plan coordinated by the French and Spanish transmission system operators (TSO), published in 2007, provided for the consolidation of the Western axis (Larrau and Biriatou) by 2013 and the creation of a new Eastern axis (Perthus) for 2015 (called the Midcap project).

OS 2013 included a non-binding (indicative) and binding phases.

OS 2013 was held in 2008 -2009 and the intention was to reach a FID in 2010 and for the capacity to enter service in 2013.

This process was closely interrelated with the Open Season 2015 (see separate description).OS 2013 carried out simultaneously the binding phase for the 2013 capacities and the non-binding phase for the 2015 capacities.

The market test

No economic test was applied on the Spanish side as the investment decision for the infrastructure was taken by its inclusion in the Spanish Central Plan. Regulated access tariffs[67] applicable in the Spanish side are approved by the Ministry of Industry aimed at assuring the investment recovery and a reasonable profit.

On The French side, it was a condition for investment that a sufficient share of the capacity offered is allocated. The following rules were adopted:

- to decide on investment at the border:
  - If less than 50% of the overall capacity offered at the interconnection between France and Spain is allocated for 10 years or longer after the allocation stages, then the capacity allocation will be considered as non-valid and no capacity booking contracts or transport contracts will be signed.
  - If more than 90% of the capacity offered at the interconnection between France and Spain is allocated for 10 years or longer after the allocation stages, then the capacity allocation will be considered as valid, and the relevant contracts will be signed.
  - If the capacity allocated for 10 years or longer after the allocation stages lies between 90 and 50% of the capacity marketed, then the decision on whether to pursue or terminate the open season will be discussed within the Implementation Group (IG) of the South Gas Regional Initiative (NRAs, Ministries and TSOs) taking into account the subsidies potentially granted by the European Energy Programme for Recovery. The priority will be given to Larrau interconnection point. Given that more of the capacity is attributed to this point.

[67] The tariff model applied in Spain is the entry-exit model with a single balancing area being uniform for the entire country. The charge for entry points consists of a uniform value for reservation capacity at any given entry points of the system. For exit points of the transmission two uniform charges are applied: the reservation charge and the usage charge, both depend on the pressure and the annual consumption at the exit point.

- Assuming the first test is satisfied, to decide on whether to invest at both physical points or only one of them:
  - If the capacity allocated for 10 years or longer lies above 288[68] GWh/d, Larrau and Biriatou will be validated by the CRE,
  - If the capacity allocated for 10 years or longer lies between 288 and 250 GWh/d, Larrau will be validated by the CRE and the decision on whether or not to allow the development of Biriatou will be discussed.
  - If the capacity allocated for 10 years or longer lies between 250 and 182 GWh/d, Larrau will be validated and Biriatou will not be validated by the CRE.
  - If the capacity allocated for 10 years or longer lies between 182 GWh/d and 101 GWh/d, the decision on whether or not to validate the capacity allocation for Larrau will be discussed and Biriatou will not be validated by the CRE.
  - If the capacity allocated for 10 years or longer is below 101 GWh/d, neither Larrau nor Biriatou will be validated by the CRE. If the capacity allocation of Biriatou is not validated and the capacity demand is above the capacity available at Larrau, then the capacity allocation applied taking into account the capacities offered at Larrau, will be the valid one. Part of the capacities is reserved for annual and seasonal subscriptions, corresponding to 20% of the technical capacities.

On reason for leaving considerable flexibility to the TSO/NRA is that using a volumetric market test the implications of the commitments is difficult to judge in advance. This is one reason for moving to a financially-based test in the subsequent 2015 OS process.

The outcome

The Joint Allocation Office received 12 requests from 8 different companies. The test passed for the allocation of capacity on the Larrau point alone.

- France>Spain: 98.6% of the capacity offered was booked.
- Spain>France: 100% of the capacity offered was booked.

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68 This refers to capacity in both directions. The total in 2013 for TIGF-Spain is South to North 180 GWh/day and North to South 118 GWh/day, a total of 298 GWh/day

Key issues identified

- The chosen allocation rules methodology was a pro-rata based on capacity requested. The allocation of capacities was fully coordinated. -
- the OS was used to obtain indicative demand for the forthcoming OS 2015 process
- Economic test: rules were clear, but not detailed enough: they did not fully anticipate the observed outcome of the OS, leaving the possible reaction to this outcome open. The rules also left substantial discretion to the TSOs and NRAs, leaving participants uncertain about the outcome
- Transparency in costs determination: estimated investment costs fluctuated during the process which had implications for tariffs and thus featured in communication between the TSO and the CRE but did not affect the market test.
- Tariff visibility – lessons learnt from the OS 2013 lead to adopting different tariffs for OS 2015.

Annexe 3: Illustrative incremental capacity projects

France – Spain IP expansion 2015

The project

The original development plan coordinated by the French and Spanish transmission system operators (TSO) and published in 2007 provided for the consolidation of the Western axis (Larrau and Biriatou) by 2013 and the creation of a new Eastern axis (Perthus) for 2015 (called the Midcat project).

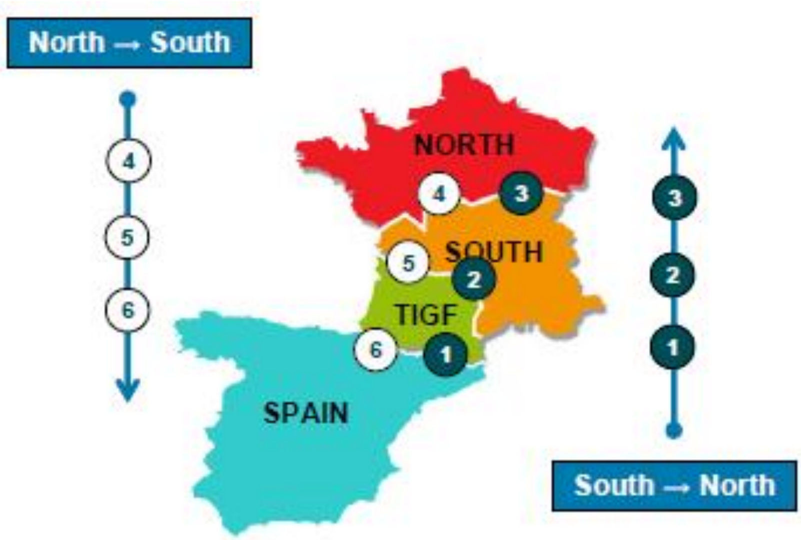
Open Season 2015 process refers to a number of different projects at two different cross-border points in combination with potential reinforcement of the capacity between the North and South two entry/exit systems of France. In summary the physical projects were:

- development of an existing interconnection at Biriatou on the Western Axis, with capacity in the N>S direction only (€110m in France) or in both directions (€190m in France), plus €35m in Spain in both cases. The Biriatou development had previously been offered in the OS 2013 but it did not pass the economic test (three alternatives including no investment);
- development of a new interconnection at Le Perthus (MidCat) on the Eastern Axis where three different levels of capacity, two of which involve flows in both directions. The costs in France ranged from € 924m to €1314m and in Spain a cost of €85m was common to all options; and
- increased capacity at the border between the North and South entry/exit systems in France in both directions.

There were nine combination of nine combination of cross-border development, each of which can be associated with existing or expanded N-S capacity in France. These 18 scenarios provide different volumes of incremental at the three interchange points shown in the graphic – using different numbers for N>S and S>N flows. Participants were asked to book capacity at these three IPs.

The promoters of the projects were GRTgaz, TIGF, ENAGAS, Naturgas Energia. EEPR funds of €74m were made available to the project.

Figure 14. IPs considered in the ES-FR 2015 open season



Source: Information Memorandum issued by TSOs

The physical and commercial capacities that were offered at the IPs between different TSOs for each of the nine project combination are summarised below.

Figure 15. Incremental capacities offered at IPs between TSOs (GWh per day)

Capacity scenario	1		2		5		6	
	New technical capacity (GWh/d)	OS commercial capacity (GWh/d)	New technical capacity (GWh/d)	OS commercial capacity (GWh/d)	New technical capacity (GWh/d)	OS commercial capacity (GWh/d)	New technical capacity (GWh/d)	OS commercial capacity (GWh/d)
MC2 + B1	290.00	228.80	230.00	239.00	240.00	192.00	240.00	192.00
MC2 + B0	290.00	228.80	230.00	239.00	180.00	144.00	180.00	144.00
MC1 + B0	290.00	228.80	230.00	239.00	80.00	64.00	80.00	64.00
MC0 + B0	290.00	228.80	230.00	239.00	0.00	0.00	0.00	0.00
MC2	230.00	184.00	230.00	184.00	180.00	144.00	180.00	144.00
MC1	230.00	184.00	230.00	184.00	80.00	64.00	80.00	64.00
MC0	230.00	184.00	230.00	184.00	0.00	0.00	0.00	0.00
B1	60.00	44.80	0.00	55.00	60.00	48.00	60.00	48.00
B0	60.00	44.80	0.00	55.00	0.00	0.00	0.00	0.00

Note that in the case of Biriatou existing capacity is included in the new technical capacity.

The development of interconnection capacity between France and Spain aims to step up the integration of Iberian, French and North-European markets. The project aims to improve the security of supply for France and the Iberian Peninsula and to develop the French gas market in the southern part of the country.

Annexe 3: Illustrative incremental capacity projects

The process

OS 2013 was used to assess the level of interest in ES-FR capacity so OS 2015 did not have a non-binding phase.

A detailed information memorandum was issued for the binding phase setting out information on the projects explaining how to book capacity and how the offers would be assessed in order to decide what combination of investments to undertake.

Specifically, participants were invited to express their demand for capacity at the 6 IPs (taking each direction as a separate IP) at 6 different price steps above the reserve price (equalised entry tariff into France) ranging from zero to €50/MWh/day. Tariffs were also payable on the Spanish side of the border.

Bidders were able to request coordinated allocation and specific the IPs at which they wished allocated capacities to be linked.

Allocation was done jointly the TSOs.

The market test

There was no economic test on the Spanish side of the border. The Spanish TSOs agreed to invest if the projects on the French side went ahead.

On the French side, two different economic tests based on the same principles were applied:

- one test to validate capacity allocations at Spain-TIGF and TIGF-GRTgaz South interconnections ;
- One test to validate capacity allocations at the N and S entry/exit systems within GRTgaz own network.

Capacity allocations in France would only be validated if the revenues generated by these allocations cover 70% or more of the costs of the infrastructures associated with these allocations during 10 years <u>without</u> discounting. The info memo states that 30% of the costs were to be socialised to all users.

The economic test to validate capacity allocations at Spain - TIGF and TIGF - GRTgaz South interconnections was based on the following principles:

1. The test was applied in this order to the following three alternatives of infrastructures:
   "MidCat + Biriatou/Irun"
   "MidCat"
   "Biriatou/Irun"
2. Solutions based on investments optimisation (reduction of the capacity offered from France to Spain to minimise investments) are tested for the three alternatives.

3. If 2 or more investments scenarios can equally satisfy the provisional aggregated capacity allocations communicated by TSOs, then the economic test would validate the scenario which minimises the price at IP1.

Once the outcome of the economic test was established, there a set of priority rules and allocation rules were used to assign the capacity to participants.

The outcome

The open season 2015 ended on July 16, 2010. The results were as follows:

- Expressed demand and the positive outcome of the corresponding economic test validated the development of incremental capacity of 50 GWh/day from Spain to France at Biriatou from 2015 onwards. Three shippers were allocated the corresponding capacity from Spain to PEG North;
- The requests were too small to trigger the development of the Midcat project; and
- No capacity has been allocated by the carriers from GRTgaz-North to Spain.

French TSOs took corresponding investment decisions and CRE validated these decisions by January 31, 2011.

Key issues identified

The following issues may be noted in this case:

- the complexity arising from the interactions between different projects in a gas corridor;
- the scope which was used in the OS to permit participants to link their allocation requests across more than one IP;
- Economic test: rules were clear, but not detailed enough: they did not fully anticipate the observed outcome of the OS, leaving the possible reaction to this outcome open Transparency in costs determination: investment costs fluctuated during the process.

Germany-Poland IP expansion at Lasow

The project

The existing entry point into Poland from Germany at Lasów has a technical capacity of 180,000 m3/h in the DE>PL direction and is heavily utilised to by 14 shippers to import cheaper gas from Germany into Poland.

GAZ-SYSTEM, the Polish TSO developed a project to reinforce the Polish grid to permit an increase of about 50% in the import capacity into Poland, equivalent to a total capacity after the project of 1.5 bcm/y[69]. The project involved some 90kms of new pipeline at an approximate cost of €65 million. All of this would be incurred in Poland – no investment was required in Germany.

GAZ-SYSTEM does not provide information on any assessment of the project benefits it may have undertaken.

The process

A binding open season process for the additional capacity was conducted in 2011. The capacity offered was unbundled – Polish entry point only. 100% of the increase was offered in 2012 and 2013 but only 90% in 2014 as a decision was made to offer 10% of the capacity during the course of 2013as a bundled product jointly with ONTRAS, the corresponding Germany TSO.

Capacity was not offered beyond 2014.

Shippers were invited to apply for capacity under the current pricing methodology, i.e. at a floating tariff. In the event that aggregate demand exceeded incremental capacity, requests were scaled back on a pro rata basis.

The market test

There was no market test involved in the OS process – it was simply an allocation process.

GAZ-SYSTEM were confident that the capacity would be subscribed and made the investment decision independently of the outcome of the OS process in consultation with the national regulator, URE.

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69 The additional capacity is given as additional capacity of 46,800 m3/h.

The outcome

No issues were encountered during the process and 27 shippers were successful in being granted capacity. All capacity offered was allocated.

Key issues identified

The main issue is the strong interest in the development of gas interconnection with Germany in order to import cheaper gas relative to that available in Poland.

During the course of 2014 GAZ-SYSTEM and ONTRAS are planning one of the first offering of bundled capacity under the NC CAM rules.

Annexe 3: Illustrative incremental capacity projects

Open Grid Europe general grid reinforcement

The project

Open Grid Europe, formerly E.ON Gastransport, operates the largest transmission system (total length approx. 12,000 km) in Germany, comprising both H gas and L gas networks. The merger of OGE's entry/exit systems for L and H gas and cooperation with other TSOs created Network Connect Germany (NCG), a large virtual trading point.

In 2008 the company embarked on an open season process to assess network users (shippers and downstream networks) requirement and expectations for additional exit and entry capacity at over 60 points on both the H and L gas systems.

The main benefits would be to provide network users with additional capacity to flow gas and to increase further the liquidity of NCG. Network stability/security of supply and network integration were also recognised as benefits.

The process

The OS was expected to fall into the following steps:

- a non-binding comprising requests for capacity without obligations (Phase 1);
- analysis of the requirement network expansions, determination of the investment required and formalisation of revised network charges under the main regulation, the GasNEV;
- submission of binding commitments by network users for capacity (Phase 2);
- capacity allocation and conclusion of contracts; and
- construction work to have capacity in service by 2012.

In the event, demand significantly exceeded expectations in both phases. Indeed, so high was demand that the investment exceeded what the company could finance. A prioritisation process had therefore to be introduced, in close consultation with BNetzA. The result was a delay of around 9 months.

Key indicators of the different phases are summarised below. The final outcome provided about 30% of the capacity originally requested.

Table 8. Key indicators of phases of the OS

	Phase 1	Phase 2	Prioritised
Users	102	44	40
No of requests	485	169	132
Capacity GWh/h	357	107	31
Investment € billion	7.2	3	0.4

Source: OGE

The market test and prioritisation

From the outset in January 2008, the general rules of the open season stated "that in order to obtain an appropriate, reliable basis for investment decisions by E.ON GT in view of the considerable investments required, the following restrictions shall apply to the new transmission capacities to be created for shippers at the various entry and exit points:

- At least 80 % of the new transmission capacity shall be covered by long-term capacity contracts with a term of at least 15 years;
- No more than 5 % of the new transmission capacity shall be covered by capacity contracts with a term of less than 5 years."

This is known as the 80/5 rule.

The high demand noted above applied in spite of these restrictions.

During the prioritisation stage the following ranking criteria and corresponding weights were applied to decide which projects to undertake:

- efficiency based on binding request indicating willingness to pay (50%)
- network related criteria:
  - network stability and security (15%)
  - network integration and connection (10%)
- competition related criteria:
  - debottlenecking based on number of interrupted days in last 3 years (15%)
  - trading competition, based on users share of capacity at each point (10%).

Annexe 3: Illustrative incremental capacity projects

The outcome

The scale of demand was not foreseen and this led a signficantly longer open season process resulting in only some one third of the original requests being met. The projects have moved forward and the incremental capacity was commissioned in 2012.

Key issues identified

The key issues were:

- unexpectedly high demand for capacity resulting in an expansion plan that could not be delivered financially, in spite of the 80/5 rule – this occurred because user demand had not been generally tested beforehand;
- the challenges of reaching agreement on non-financial criteria for use in prioritising projects.

OGE notes that a few years after the OS demand for capacity has changed dramatically. There is now capacity available at point that were originally heavily requested in the OS.

Austria – Slovenia IP expansion

The project

The existing interconnector has a capacity of just over 100 GWh/day in the direction AT>SI. Investment was needed on the Slovenia side and downstream in the main Slovenia grid to increase capacity. In order to reach final capacity of the IP according to the Interconnection AT-SI project additional investment is needed also in Austria therefore the cooperation of neighbouring TSO is required to put greater capacity to use.

The project would increase the capacity of the IP to 265 GWh/day (1.005 million m^3/hour). Over 90% of currently available capacity is booked by some 150 shippers serving the national market and 10 international shippers.

The total investment cost, including essential backbone development, is given as app. €400 million (Source: Plinovodi d.o.o.). The actual interconnection project of 160 meters only accounts for a small part of the total cost.

The promoter is the Slovenia TSO, Plinovodi d.o.o.

The benefit of the project are primarily the increase of transmission capacities, improvement of security of supply, increase of competitiveness, increase of liquidity of the market and the ability to bring lower cost gas from Austria and beyond to Slovenia where gas prices are significantly higher. Some international shippers are interested to import and then export gas to Italy.

The process

The project was part of Plinovodi's Development Plan for the Gas Pipeline System 2005-2014.

The main feature of the process was the preparation and approval of a Detailed Plan of National Importance (DPNI) in order to gain planning approval and the approval of the Ministry responsible for energy. In effect investment in the project was approved on the basis of this DPNI, following a public consultation process. The projects connected to the Interconnector AT-SI project also qualified for support under the EEPR.

The process of preparing the DPNI included an assessment of likely demand for capacity in 2005 but there was no open season.

The incremental capacity in the Slovenian gas system is now nearing completion and is expected to be allocated on the basis of an auction on the same principle as the draft NC CAM.

Plinovodi has not yet decided whether to become a user of Prisma.

The market test

Not applicable in this case. The investment decision for the work on the Slovenian gas system was made on the basis of Plinovodi's Development Plan for the Gas Pipeline System 2005-2014 confirmed by Company Supervisory Board.

The outcome

Construction of additional capacity of the Slovenian natural gas transmission system is now nearing completion.

The Interconnector AT-SI project is not yet in FID phase.

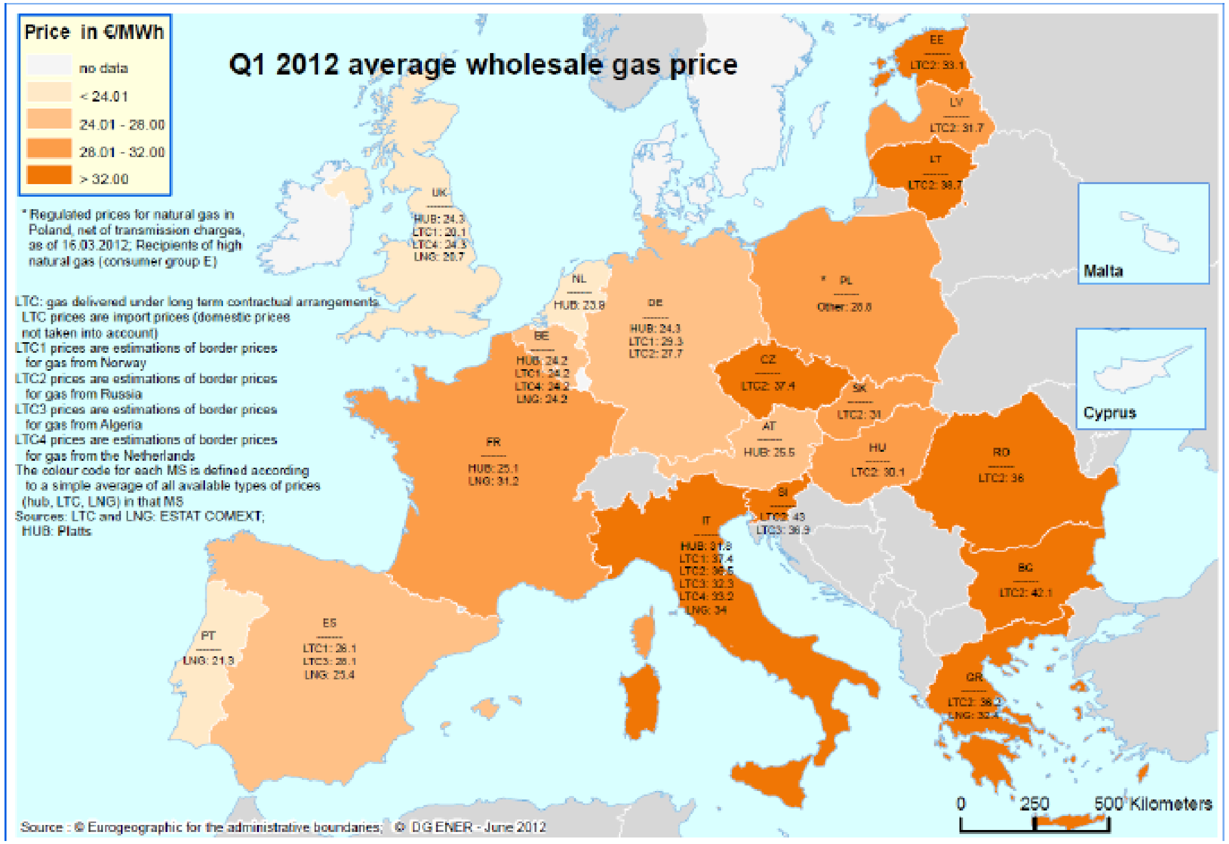
Key issues identified

No major issues identified.

It is of interest that the benefits of some investment projects are sufficiently apparent that they can gain approval without any form of market test or requirement for any of the capacity to be booked on a binding basis before the final investment decision is made.

Annexe 3: Illustrative incremental capacity projects

Annexe 4: Map of EU wholesale gas prices in Q1 of 2012



Quarterly Report on EU Gas Prices, DG Energy, June 2012

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