The Brattle Group

# Impact Assessment for the Framework Guidelines on Harmonised transmission tariff structures

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Version with Evaluation Tables Included

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# 1 INTRODUCTION

Regulation 715/2009 (hereafter referred to as the Gas Regulation) requires network codes to be established. These codes will cover twelve areas related to gas use and gas transmission, and the Gas Regulation assigns responsibility for producing the network codes to the European Network of Transmission System Operators (ENTSOG). The Gas Regulation also specifies that the Agency for the Cooperation of Energy Regulators ('the Agency') is responsible for producing Framework Guidelines (FG) for the network codes, and that ENTSOG will follow the Framework Guidelines when drafting the network codes. The development of Framework Guidelines involves three steps:

1. Publication of a consultation document on the Framework Guidelines;
2. An Impact Assessment of proposed Framework Guidelines;
3. Drafting of the detailed guidelines.

One of the network code areas specified in the Gas Regulation is rules for harmonised transmission tariff structures. In February 2012 the Agency published a consultation document on the scope and main policy options for Framework Guidelines on harmonized transmission tariff structures, hereafter referred to as the Consultation Document.[1] The present study describes the advantages and disadvantages of possible policy options concerning the harmonization of transmission tariff structures by assessing their potential impacts.

We have structured this study according to the key analytical steps set out in the European Commission's Impact Assessment methodology.[2] This methodology involves the following steps:

1. What are the policy objectives?
2. What is the problem, or problems that the proposals are trying to address?
3. What are the policy options?
4. What are the likely economic, social and environmental impacts?
5. How do the options compare?

However, before starting with the formal impact assessment steps, we begin with a discussion of recent relevant developments in the EU gas market rules and regulations which could have a bearing on the work.

[1] ACER "Scope and main policy options for Framework Guidelines on harmonized transmission tariff structures: Consultation document", DFGT-2012-G-004, February 8, 2012.

[2] See for example European Commission, Impact Assessment Guidelines, 15 January 2009 SEC(2009) 92.

## 2 CONTEXT OF THE IMPACT ASSESSMENT

### 2.1 OTHER RELEVANT NETWORK CODES AND FGS

As the Consultation Document points out in section 2, the development of harmonized tariff codes are highly dependent on other code developments. In March 2012 the European Commission gave an updated on the Congestion Management Procedures (CMP), which the Commission expects to be adopted by September 2012.[3] The Agency has also adopted Framework Guidelines on Capacity Allocation Mechanisms (hereafter referred to as the FG CAM),[4] the CAM Network Code (NC) has been adopted and the Agency has issued an opinion on the CAM NC.[5] The Agency has also published Framework Guidelines for balancing,[6] and ENTSOG have issued a draft Network Code (NC) on balancing.[7] However, we do not see much interdependency between the balancing NC and tariff harmonisation. In this section we briefly highlight some of the most relevant developments.

### 2.2 CAPACITY ALLOCATION MECHANISMS

The FG CAM and the subsequent CAM Network Code[8] both have several elements that are relevant to tariff setting. The FG CAM requires that that "all firm and interruptible [cross-border] capacity services for each time interval, with the possible exception of within-day (intraday) capacity services, are allocated via auctions."[9] The FG CAM goes on to note that this does not rule out that these auctions could be implicit, though the default assumption and the design described is for explicit auctions. The auctions of various capacity products requires the setting of minimum, or reserve prices, which links directly to the work on the network code for tariff structures.

Article 7.3 of the CAM network code includes an approach to reserve prices based on a yearly reference price and a so called "revenue equivalence principle". In essence this approach means that for pricing capacity products with duration of less than one year, TSOs will apply a multiplier to the price of the average annual price so that the cost of multiple short-term bookings would be the same as a constant annual booking to meet the peak flow requirement. This implies that the multipliers will be higher than one for short-term reserve prices in winter, but maybe lower than one in the summer, assuming that peak gas demand is in winter. The CAM NC also specifies that interruptible capacity will be sold by auction according to the same principles as firm capacity of the same duration. However, in its Opinion, the Agency noted that Article 7.3, including the reference to the revenue equivalence principle, went beyond what was required for the CAM NC and should be removed.[10] Instead, tariff issues would be addressed by the FG on harmonised transmission tariff structures.

3 European Commission, Congestion Management Procedures, Update on progress Madrid Forum 22 – 23 March 2012.

4 ACER, Framework Guidelines on Capacity Allocation Mechanisms for the European Gas Transmission Network FG-2011-G-001 3 August 2011.

5 ACER Opinion No. 04-2012 Reasoned Opinion on the Network Code on Capacity Allocation Mechanisms for the European Gas Transmission Network. Hereafter referred to as the 'ACER CAM Opinion'.

6 ACER, Framework Guidelines on Gas Balancing in Transmission Systems FGB-2011-G-002 18 October 2011.

7 ENTSOG, Draft Code on Balancing for Consultation BAL300-12 13 April 2012.

8 ENTSOG CAM Network Code CAP0210-12 6 March 2012.

9 FG CAM section 3.1.1 p.12.

10 ACER CAM Opinion Section 9 p.7.

More generally the ACER Opinion noted that the provisions of Article 7 of the CAM NC which dealt with tariffs should only be regarded as temporary until the FG on tariff harmonisation came into force, at which point the provisions in Article 7 of the CAM NC would be repealed.

Under the FG CAM, rather than sell cross-border capacity at individual entry and exit points, TSOs will combine or 'bundle' capacity at all the border points into a single product. Shippers simply buy capacity from country A to country B, rather than buy two capacity products at either side of the border point. The scheme is also referred to as a 'hub-to-hub' service.

Where two adjoining networks are connected by two or more interconnection points, the CAM network code envisages that TSOs will establish a single virtual interconnection point (VIP). TSO will then sell capacity between the adjoining networks at the VIPs rather than at the individual physical IPs. TSOs will not be expected to establish VIPs if technical characteristics of the interconnecting transmission networks do not allow it or because a VIP would not lead to economic and efficient use of the networks. The CAM network code also specifies that capacity offered at the VIPs should be equal to or higher than the sum of the technical capacities of the interconnection points that the VIP replaces.

### 2.3 CMP Guidelines

The CMP guidelines do not directly include some tariff elements. However, there are several provisions that will change the context for tariff harmonization and have an effect on the value of capacity, the volume offered in auctions and, potentially, on TSOs' revenues.

Some of the key proposals are:

- Over-Booking And Buy-Back – Under this proposal, TSOs would offer for sale cross-border capacity than can likely be made physically available. If nominations exceed the actual available capacity, then TSOs may decide to 'buy back' capacity.
- Firm UIOLI Rights – The proposal is to make available 10% of un-nominated as firm capacity under new UIOLI rules. The rules would apply at IPs where certain capacity products are not available or clear above reserve price applies as from 1st of July 2016.
- Long-term UIOLI – Shippers that systematically underuse capacity over a relatively long-period of time, for example a year, may be forced to sell the unused capacity.

## 3 POLICY OBJECTIVES

The policy objectives for gas transmission tariffs are set out in Article 13 of the Gas Regulation and also summarised in section 3.2 of the Consultation Document. The Agency's consultation document has derived the following five potential objectives from Article 13:

- Facilitate trade and competition. Article 13(2) of the Gas Regulation requires that gas transportation tariffs neither impede the development of liquidity in the gas market nor distort cross-border trade. The pricing of capacity should thus not thwart opportunities for trading between parties where efficient and this will in turn allow competition to continue to develop. According to the Agency to achieve this objective, shippers must be able to book capacity products according to their business and risk profiles.

- Avoid cross-subsidies and undue discrimination between network users. Meeting the cost-reflectivity objective will, at least to some extent, also deal with the objective of avoiding cross-subsidies between users. Cross-subsidies may exist between domestic and transit routes if the exit charges are not cost-reflective or if different capacity: commodity splits are applied to domestic and transit routes. We expand on the trade-offs involved in more detail below.

- Cost-reflectivity. As noted above, cost-reflective tariffs will mean that cross-subsidies are minimized to the extent possible because both domestic and transit tariffs will be paying for the costs that they impose of the system.

- Promote efficient investments. Tariffs should promote efficient new investment and should provide signals, for example through auction revenues, to indicate when investment would be efficient. Tariff methodologies should not distort between new and existing investments. A situation could be imagined where existing infrastructure is under-utilised but priced at too high a price that investing in a new pipeline is more attractive. The Agency has recommended that the tariff system should use locational signals to ensure the current network is better utilized.

- Transparency. Stakeholders have indicated that one concern is the lack of transparency regarding tariffs. The concern covers various aspects of setting tariffs including the method used to calculate tariffs, how tariffs should evolve and what would trigger a regulatory change and the level of uncertainty and volatility in the tariffs. The Agency envisages that the transparency objective will cover three issues: i) transparency in the methodology used to set tariffs and ii) transparency in the signals that will be given to stakeholders with respect to costs and congestion in the system, and iii) the future evolution of tariffs. All stakeholders should be able to understand how tariffs will evolve and the factors that will affect this evolution.

## 3.1 TRADE-OFFS BETWEEN POLICY OBJECTIVES

As with many policy areas, there are tensions and trade-offs between the various objectives outlined above. This means that it will in general not be possible for a single set of tariffs to satisfy all of the objectives simultaneously. It is important to understand these trade-offs and the constraints they impose on any solution when evaluating the policy options. We describe the main trade-offs below.

### 3.1.1 Trade-offs between cost reflectivity, cross-subsidies and discrimination

While the Gas Directive and Regulation do not give a precise definition of discrimination, the examples that we have seen are concerned with charging different prices to different persons for the same service. At the time the first Gas Directive was prepared, the main concern was that gas network operators would discriminate in favour of their associated marketing affiliates, and against competing gas marketing firms, so as to prevent entry and competition in the sale of gas to end users.

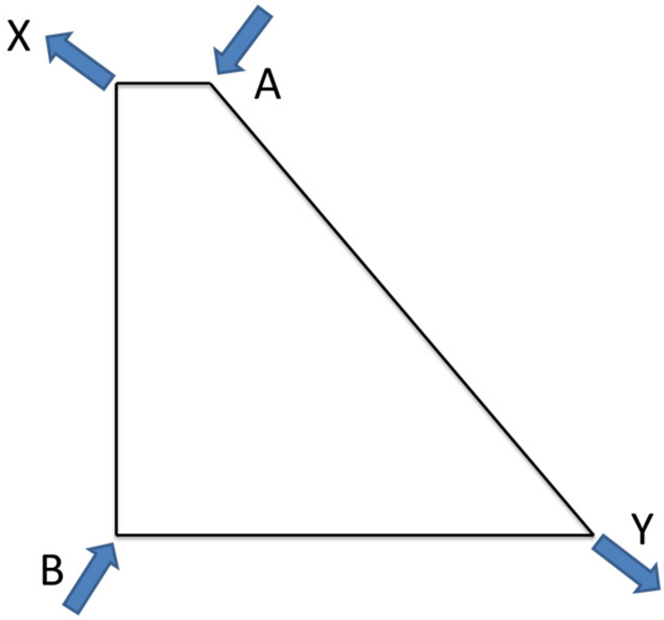
Discrimination is closely linked to the idea of *cost-reflectivity*. If tariffs are broadly cost reflective, then discrimination is not possible, since all users will be paying roughly in proportion to the costs they create. Moreover, cross-subsidy occurs only in the absence of cost-reflectivity. If tariffs were perfectly cost-reflective there would be no cross-subsidy.

If tariffs are not cost reflective, so that the price a user pays for a service is not closely related to its underlying cost, then the difference between the price of the transport service and the costs of providing it can be regarded as a penalty or burden that is born by transport customers. Hence tariffs that are not cost reflective are discriminatory, since some market participants will tend to bear a higher burden than others. Accordingly, there is a strong relationship between the objective of non-discrimination and the objective of cost-reflectivity.

However, it is also important to understand that *full cost reflectivity is not possible in an Entry Exit (EE) system where tariffs are based on the average cost of the system*. The objective should therefore be interpreted as therefore broad cost reflectivity rather than absolute cost-reflectivity for every capacity contract. Similarly, a certain amount of cross-subsidy is inevitably if tariffs cannot always be perfectly cost-reflective.

To see why absolute cost reflectivity is not possible in an EE system, consider the example of the simple network represented in Figure 1 below, with two entry points (A and B) and two exit points (X and Y). Suppose that the average cost of gas transportation is the same along BY and BX, but the average cost of transportation along AX is much lower than along AY. If in this instance the goal is to set charges so that tariffs reflect average costs, then the charges for using BY and BX must be the same, which necessitates equal exit charges at X and at Y. However, this implies that the charge for using AX is the same as the charge for using AY, despite the assumed difference in average costs. In this example it is not possible to set entry and exit charges so as to fully reflect average costs.

**Figure 1: Entry-Exit Charges and Average Costs Example**




Arguably there is also a trade-off between cost-reflectivity and transparency. A tariff that is 100% cost reflective may be highly complex and therefore lack transparency. A number of stakeholders have also urged avoiding tariff systems that are too complex.

#### 3.1.2 Trade-offs between cost recovery and promoting trade

Another key trade-off is the balance between facilitating short-term gas trading on one hand and allowing cost recovery on the other. In the absence of congestion it would seem efficient to allow prices in neighbouring markets to converge through a process of arbitrage. If the cost of the pipeline capacity is seen as a 'sunk cost', then it would be efficient to trade whenever the price difference between two market areas exceeds the marginal cost of transporting gas. This kind of trading will maximise welfare – meaning that if the price of gas in one area is €20/MWh and the price in the other is €21/MWh, then there is a 1€/MWh gain from the trade – both the buyer and seller are better off. Applying a price for short-term capacity related to long term sunk costs could be inefficient in the short-run, because it would block such welfare enhancing trades.

However, a short-term price of zero or close to zero raises issues for cost-recovery, if low or zero short-term prices incentivise more shippers to make multiple cheap or free short-term bookings in place of long-term bookings,[11] leading to a 'flight to short-term capacity'. Un-booked long-term capacity would then roll over into the short-term mechanism, until eventually all of the capacity at the border is being sold for little or nothing. This situation would require greater use of revenue recovery mechanisms to deal with the resulting revenue under-recovery problem. But this in turn could lead to a lack of cost-reflective charging, since the costs of the original IP investment might need to be recovered from, for example, domestic users.

[11] See section 4.4 for examples.

# 4 PROBLEM IDENTIFICATION

In this section, we describe problems that arise from a lack of harmonization in gas transport tariff systems. Problem identification is a key element of both the Impact Assessment and the justification of the final Framework Guideline recommendations. Harmonization of tariff structures will have a cost. This is both because some costs may be incurred in moving from the *status quo* to the harmonized approach, and because the harmonized approach may not be optimal for every market or situation. Therefore a proposal to harmonize should be addressing a problem that has been described carefully, so that it is clear that benefits of solving the problem outweigh any costs involved.

While a great many improvements have been made to EU gas transport tariff regimes since the start of the liberalization project, clearly a great number of issues remain. It is not our objective to describe all of the problems which relate to gas transmission tariffs. Rather we describe a subset of issues *which result from differences in tariff methodologies between TSOs, and which could have an adverse effect on the policy objectives described in the previous section*. In other words, we only address problems which are linked directly to either the price at which transmission services are sold or the recovery of allowed revenues by TSOs. In a number of places, we refer to details of existing EU tariff methodologies and systems. In these cases, we have relied on the information provided by the Agency and NRAs.

Our report specifically does not describe problems which arise from:

- Differences in methodologies for the determination of allowed revenues for TSOs. This is outside of the scope of the Consultation Document. NRAs are free to determine allowed revenues as long as the methodology is consistent with the Gas Regulation and the Gas Directive.

- Problems that are already addressed by existing legislation. For instance, the KEMA/REKK 2009 report provides an example of a TSO that uses an entry-exit tariff system for domestic routes and a point-to-point tariff system for transit routes.[12] KEMA/REKK argue that in this case it would be difficult for the gas planned for transit to be diverted for sale at the national hub, thereby restricting potential liquidity at the hub. However, the sale of point-to-point capacity is not consistent with Article 13(2) of the Gas Regulation and so is contrary to EU law. The point was also reported by KEMA/REKK.[13] Therefore new rules are not required to solve such a problem.

We also do not address problems that have been addressed, or will likely be addressed, by the CAM or other network codes. For example one problem mentioned in a Gas Tariffs FG Expert Group Meeting was that different physical IPs between the same market areas could have different prices. This could lead to inefficient use of the IPs, with some being congested while others have

[12] KEMA and REKK "Study on Methodologies for Gas Transmission Network Tariff and Gas Balancing Fees in Europe", December 2009, p. 48. Hereafter referred to the "KEMA/REKK report".

[13] KEMA/REKK report, p. 105.

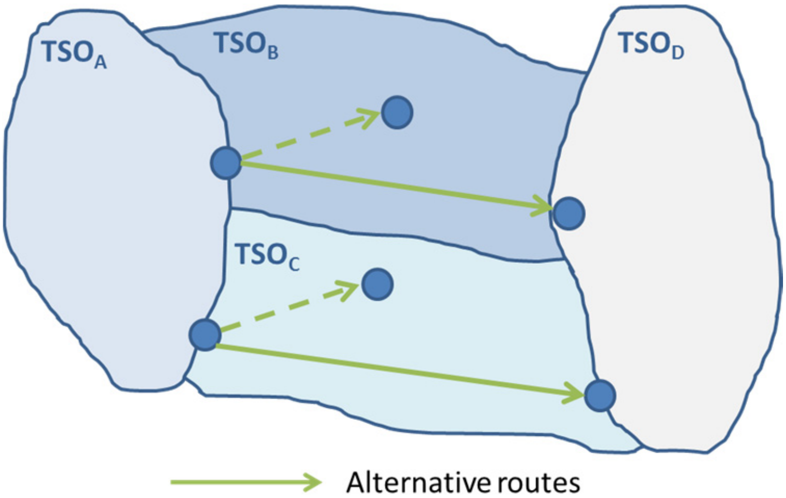
spare capacity. However this issue should be solved by the proposal to create bundled or 'Virtual IPs', as described in the CAM section.

### 4.1 *Problem 1*: Differences in cost allocation distort long-term cross-border flows

Differences between cost allocation approaches among alternative routes could lead shippers to make decisions which minimize costs for themselves, but do not minimise the costs for the EU network as a whole. In this sense a lack of harmonisation may lead to inefficiencies because shippers may chose a more congested route because it appears to be cheaper than a less congested route. This may lead to distorted investment decisions because routes that in a harmonized world would have spare capacity become congested.

Figure 2 provides a simplified example (based on Figure 3) of alternative routes through two different networks. In our example, a user has gas supplies which originate in network $TSO_A$ and would like to serve a consumer in $TSO_D$. The shipper can either use the route through $TSO_B$ or the route through $TSO_C$. We assume that the networks of $TSO_B$ and $TSO_C$ are both identical to the network shown in Figure 3 in that they have one cross-border route and one domestic route. In Figure 2 domestic entry and exit routes are represented by the dotted or broken line.

**Figure 2: Alternative pipeline routes**




This alternative route scenario is important because shippers or network users sometimes have a choice of networks for some cross-border transactions. For example:

- Between Germany (NCG) and Italy, users can choose between the Transitgas pipeline system in Switzerland and the CEGH's market area in Austria.
- Between Germany (NCG) and Austria (CEGH) users can choose to transport gas via the BOG/WAG pipeline in Austria or the Net4Gas network in the Czech Republic and then the Eustream network in the Slovakia.

- North Sea gas can enter the EU gas network through a number of alternative entry points: the GTS network at Emden, the Gaspool/NCG market areas at Emden/Bunde, the GRTgaz network at Dunkerque and Fluxys network at Zeebrugge.

As more projected new pipelines come on-line the opportunities for competition between routes will increase. For instance, the undersea interconnector between Italy and Greece and the Nabucco/South Stream pipelines could provide competing routes between south-east Europe and the rest of Europe. For example gas in Austria could reach Greece either via SnamRete Gas's network in Italy or perhaps via the South Stream/Nabucco pipelines through Romania and Bulgaria. The various LNG terminals around the coastline of the EU also present many opportunities for competition between routes.

While in general terms most NRAs and TSOs in the EU use a similar mechanism for setting tariffs, the details of the mechanisms vary widely. The typical steps for setting tariffs are:

1. First, the NRA determines the TSO's or allowed revenue. This is usually determined by a combination of depreciation, return on capital and operating costs;
2. A forecast is made for capacity/throughput demand for each entry and exit point over the regulatory period and also in some cases the distance that the gas will travel;
3. The costs that must be recovered from each entry and exit point is then determined. We refer to the process of allocating costs that must be recovered from groups of entry and exit points as *cost allocation*;
4. Finally, the *reference price* at each entry and exit point is determined. Often, this is done simply by dividing the costs allocated to that point by the expected demand at that point (or group of points).

A further issue is whether there is a system of revenue regulation or price regulation. Both systems require the four steps above. The key difference is that under revenue regulation, if the volumes are more or less than anticipated when the price was set then future tariffs will be adjusted so that the TSO obtains its allowed revenues – no more and no less. under price regulation, the TSO accepts a volume risk, so that it will earn less than projected if volumes are lower than expected. In return, the TSO may earn a higher cost of capital than a similar TSO with revenue regulation. Both systems are equally valid, but revenue regulation creates the additional issue of how to recover revenues that were not recovered in a previous period.

There are a great many ways to perform cost allocation in step 3 above. These different approaches can produce very different reference prices even for the same set of allowed costs and forecast demand. The main scope for differences at step 3 are:

i) whether costs are allocated with respect to long-run marginal costs (LRMC)[14] or historical costs;
ii) how costs are allocated between domestic and cross-border routes;

14 Allocating costs with respect to LRMC describes the process by which the allowed costs are allocated among routes in relation to the level of congestion along the routes. For instance, a route that is more congested will be allocated more of the allowed costs than a less congested route.

iii) how the costs are divided between entry and exit points; and
iv) how the costs are allocated between capacity and commodity components of a tariff.

Different approaches for any one of these components can result in tariffs that differ for reasons that do not reflect underlying costs or congestion, but instead reflect different choices regarding the cost allocation methodologies. We explain how the different cost allocation components could affect reference prices and hence cross-border flows in the sections below.

**LRMC versus historical costs**

The use of LRMC versus historical costs for cost allocation is important because the same pot of allowed revenues would produce a different set of reference tariffs if LRMC were used as the basis for cost allocation instead of historical costs. To demonstrate this point we use an example of a simplified network with just two pipelines as shown in

Figure 3. One of the pipelines is a cross-border route while the other serves a domestic consumer. The two pipelines have the same cost per km but the cross-border pipeline is twice as long as the domestic pipeline. The allowed revenue for the whole network is €15. We consider four different scenarios which differ by whether cost allocation is respect to LRMC or historical costs and whether or not the domestic pipeline is closer to congestion than the cross-border pipeline.

**Figure 3: Simplified network example**

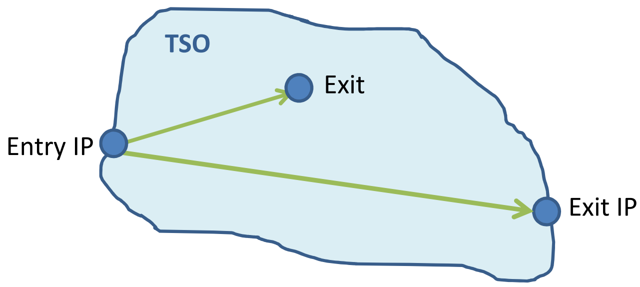



Table 1 shows how the cost allocation can vary between the different scenarios. When a historical cost approach is used, the cost allocation is the same whether or not one of the routes is close to congestion. When LRMC is used, the allowed costs are split equally between the pipes when neither pipeline is close to congestion, but the domestic pipeline is allocated much higher costs when it is the most congested.[15]

**Table 1: Cost allocation based on LRMC versus cost allocation based on actual costs**

[15] For this case we have assumed that 12 is allocated to the domestic route and 3 to the cross-border route.

| | Historical costs approach | | LRMC approach | |
|---|---|---|---|---|
| | Cost allocated to: | | Cost allocated to: | |
| | Cross-border route | Domestic route | Cross-border route | Domestic route |
| No foreseeable congestion; same for both routes | 10 | 5 | 7.5 | 7.5 |
| Domestic route more congested | 10 | 5 | 3 | 12 |

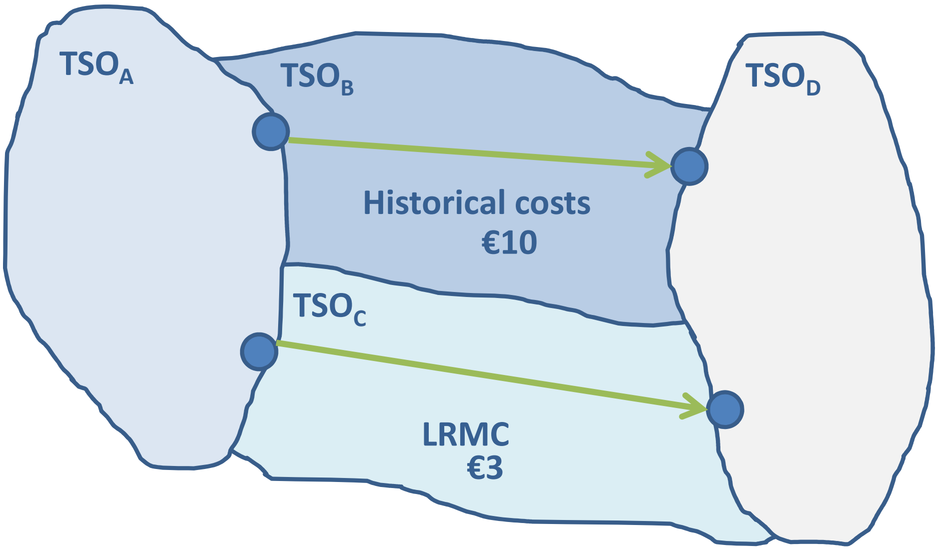
Our above LRMC example assumes that allowed costs are distributed among the network routes or entry/exit points in proportion to LRMC. The LRMC for each route (or entry/exit point) are identified and then scaled-up or down so that the total of the costs allocated equals the allowed costs. Alternatively, LRMC can be also be used directly as a reference tariff. For instance, a TSO could set the costs to be recovered at entry IPs at the LRMC of increasing capacity at that entry point. The TSO could then recover remaining allowed costs from exit points and/or a commodity charge. This approach is no different to the cost allocation approach used in our LRMC example. It is just that no scaling factor is applied to the capacity component of IP entry points. Instead the scaling is applied to the commodity charge and/or exit charges.

We now extend the example above to consider the case where $TSO_B$ allocates costs with respect to historical costs and $TSO_C$ allocates costs with respect to LRMC. We again use our simplified example from

Figure 3 and Figure 2 where the underlying costs of TSOB and TSOC are each €15 and consider the case where the domestic route is congested. In TSOB, the cross-border route is therefore allocated €10 of costs while TSOC is allocated €3 of costs (see Figure 4).[16] The remaining €5 of costs in TSOB and €12 in TSOC are allocated to the domestic route.

16 We assume that there are other routes through C that are close to congestion and that the LRMC assigns a tariff lower than average costs to the route in our example.

**Figure 4: Cross-border distortions from cost allocation methodologies**




Although both routes have identical actual costs, the different cost allocation methodologies mean than route through $TSO_C$ appears to be the cheaper route and so the shipper prefers this route. In this example, the different reference price setting methodologies distort the cross-border flows in favour of route C. The problem could be exacerbated by price pancaking if route B went through several market areas all based on historical costs and route C went through several market areas based on LRMC.

The outcome would be the same even if the route through network C was more congested than the route through network B. As long as the domestic route in $TSO_C$ was closer to congestion than the cross-border route, the cross-border route through network C would always be cheaper that the cross-border route through B. This would be the case even if the route through C had less spare capacity than the route through B. The different methodologies prevent locational signals for efficient use of the network before congestion arises. Once the cross-border routes through $TSO_B$ and $TSO_C$ become congested, the correct mechanisms should be in place to provide the right locational signals for efficient network use. The price for capacity will be set through an auction process, and so we can expect the price of the routes to rise as the route becomes congested. Once the price of route C exceeds the costs of route B, shippers will then switch to route B.

The gas network charges for Great Britain are probably the most prominent example of the use of LRMC-based tariffs in the EU.[17] In GB, LRMC is used as an ingredient in setting auction reserve prices and exit tariffs. The GB TSO, National Grid Gas, calculates the LRMC of reinforcing the network to accommodate additional supply/demand at entry/exit points. However, setting the capacity tariffs at the LRMCs are unlikely to recover the allowed revenues of the TSO, at least in the GB system. For this reason NGG scales up the tariffs which have been calculated based on the LRMC calculations. In performing this type of scaling, GB uses two objectives: 50% of the allowed revenue for capacity charges are recovered through the exit capacity tariffs (this is done by LRMCs

[17] See National Grid, Overview of Gas Transmission Charging July 2011 for more details of the GB charging regime.

for all exit points being uplifted by a common additive factor to recover 50% of allowed revenue) and the other 50% of the allowed revenue is recovered from entry charges (the LRMC is used as the auction reserve price at entry points and any shortfall on recovering 50% of allowed revenues is done by applying a charge on actual flows – the commodity charge). As the two mechanisms of exit additive factor and entry commodity charge in GB are set ex-ante two regulatory accounts are also needed (one for entry revenues and one for exit revenues) which are reconciled every year.

Portugal also uses a scaled-LRMC in tariff setting and we understand that Ireland will move to a system where entry tariffs are based on LRMC. Both Great Britain and Portugal could both potentially be involved in the types of alternative routes we describe above. Great Britain is one of several routes for Norwegian gas to continental Europe and LNG supplies into Portugal could compete with gas supplies sourced from elsewhere.

#### Differences in cost allocation to entry/exit

When allocating costs between entry and (domestic and IP) exit points, a TSO may try to identify the actual costs associated with the entry (or exit) points as in Belgium. Alternatively a TSO might split the costs associated with each route equally between the relevant entry and exit points as in Italy. In Germany, we understand that the costs are allocated to entry/exit points in proportion to the booked capacity and this type of approach could result in the same tariff for each entry/exit point.[18] TSOs have also used optimization processes that involve identifying the actual cost of each route and then finding the sets of entry and exit tariffs that most closely produce the actual cost for each route when the tariffs are applied to expected capacity bookings. This type of approach has been applied in Italy. As a result of these different methodologies, different NRAs/TSOs allocate the costs that they must recover from entry and exit points in large variety of ways. For example, the THINK study notes that in Portugal tariffs are calculated with a resulting entry-exit split of 26:74, while the Czech Republic actively wants to promote imports and market entry and therefore applies a cost split between border entry- and exit points of 22:78.[19] Figure 5 illustrates other examples of entry and exit cost allocations for other MSs.

[18] Information provided by the Agency.

[19] The THINK study reports how the split of costs between entry and exit points varies among countries. See the THINK report, p.38.

**Figure 5: Division of costs between entry and exit points for a sample of TSOs and gas transport transactions**[20]

*Table 6: Entry/Exit split for distances 60km, 110km, 260km and 350km.*

| | | 60 km | 110 km | 260 km | 350 km |
|---|---|---|---|---|---|
| France | GRTgaz | 83/17 | 73/27 | 63/37 | 59/41 |
| France | TIGF | 34/66 | 34/66 | 32/68 | 33/67 |
| Belgium | Fluxys | 19/81 | 19/81 | 19/81 | 19/81 |
| Denmark | Energinet.dk | 50/50 | 50/50 | 50/50 | 50/50 |
| Hungary | MOL | 77/23 | 77/23 | 77/23 | 77/23 |
| The Netherlands | GTS | 59/41 | 54/46 | 38/62 | 26/74 (1)<br>50/50 (2) |

To illustrate the effect of differences in entry exit cost allocation, we return to our earlier example in

Figure 3 and assume that the cost for the cross-border route is 10 and for the domestic route is 5. We also assume that 1 unit of capacity is booked along each of the cross-border and domestic routes.

Suppose that if, as in Italy and Denmark, 50% of costs are allocated to the entry point and 50% to the exit point, we would derive the cross border tariff as follows. 50% of the cross-border costs (of €10) and 50% of the domestic costs (of €5) would be allocated to the entry point this results in a cost of (0.5 x €10) + (0.5 x €5) = €7.5 being allocated to the entry point. Total gas flows at the entry point are 2, so the unit reference price is 7.5/2 ≈ €3.8. At the cross-border exit point, the cost allocated is simply 0.5 x 10 = €5, and there is 1 unit of flow, so the price is €5. This gives a total (entry + exit) reference price for the cross-border flow of €8.8. Table 2 illustrates the calculation. Note that €8.8 is less than the assumed cost of the cross-border route which is €10.

Table 2 illustrates a range of calculation for different cost allocation assumptions. If instead 25% of the costs were allocated to the entry point, which is approximately the percentage of costs allocated to entry points in Belgium, the Czech Republic, Spain and Portugal, the costs recovered from the cross-border route would be €9.4. If more costs were allocated to the entry point, as is the case in Hungary, the recovered costs would be lower. In our simplified example when 75% of the costs are allocated to the entry point (which is comparable to Hungary), the costs recovered from the cross-border route is €8.1.

[20] Gas Transmission Tariffs an ERGEG Benchmarking Report C06-GWG-31-05 18 July 2007 p.16.

**Table 2: Cross-border tariffs for different entry/exit splits**

| | | | % of costs allocated to entry | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 90% | | 75% | | 50% | | 25% | | 10% | |
| | | | cross-border route | domestic route | cross-border route | domestic route | cross-border route | domestic route | cross-border route | domestic route | cross-border route | domestic route |
| Capacity booked | [1] | Assumed | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Costs: | | | | | | | | | | | | |
| Total | [2] | Assumed | 10 | 5 | 10 | 5 | 10 | 5 | 10 | 5 | 10 | 5 |
| % allocated to entry | [3] | Assumed | 90% | 90% | 75% | 75% | 50% | 50% | 25% | 25% | 10% | 10% |
| % allocated to exit | [4] | Assumed | 10% | 50% | 25% | 25% | 50% | 50% | 75% | 75% | 90% | 90% |
| Allocated to entry | [5] | [2]x[3] | 9.0 | 4.5 | 7.5 | 3.8 | 5.0 | 2.5 | 2.5 | 1.3 | 1.0 | 0.5 |
| Allocated to exit | [6] | [4]x[2] | 1.0 | 2.5 | 2.5 | 1.3 | 5.0 | 2.5 | 7.5 | 3.8 | 9.0 | 4.5 |
| Entry tariff | [7] | See note | 6.8 | 6.8 | 5.6 | 5.6 | 3.8 | 3.8 | 1.9 | 1.9 | 0.8 | 0.8 |
| Exit tariff | [8] | [6]/[1] | 1.0 | 2.5 | 2.5 | 1.3 | 5.0 | 2.5 | 7.5 | 3.8 | 9.0 | 4.5 |
| Total tariff | [9] | [7]+[8] | **7.8** | | **8.1** | | **8.8** | | **9.4** | | **9.8** | |

Notes and sources:
[7]: Sum of [5] for domestic and cross-border routes divided by the sum of [1] for domestic and cross-border routes.

The numerical example illustrates that the price of the cross-border route in this example can vary from €7.8 (when 90% of costs are allocated to entry points) to €9.8 (when 10% of costs are allocated to entry points). Accordingly, a situation could arise with two TSOs with exactly the same networks and costs where one TSO charges €7.8 for the cross-border route and the other charges €9.8, purely as a result of different allocation of costs to entry and exit points.

### Allocating costs between domestic and cross-border routes

The example above could be combined with a case where there is different cost allocation between domestic and cross-border routes – so instead of starting with a cost of €10 for the cross-border route and €5 for the domestic route the cost base could be set at €13 and €2 respectively. Adding this variable would result in an even broader range of tariffs.

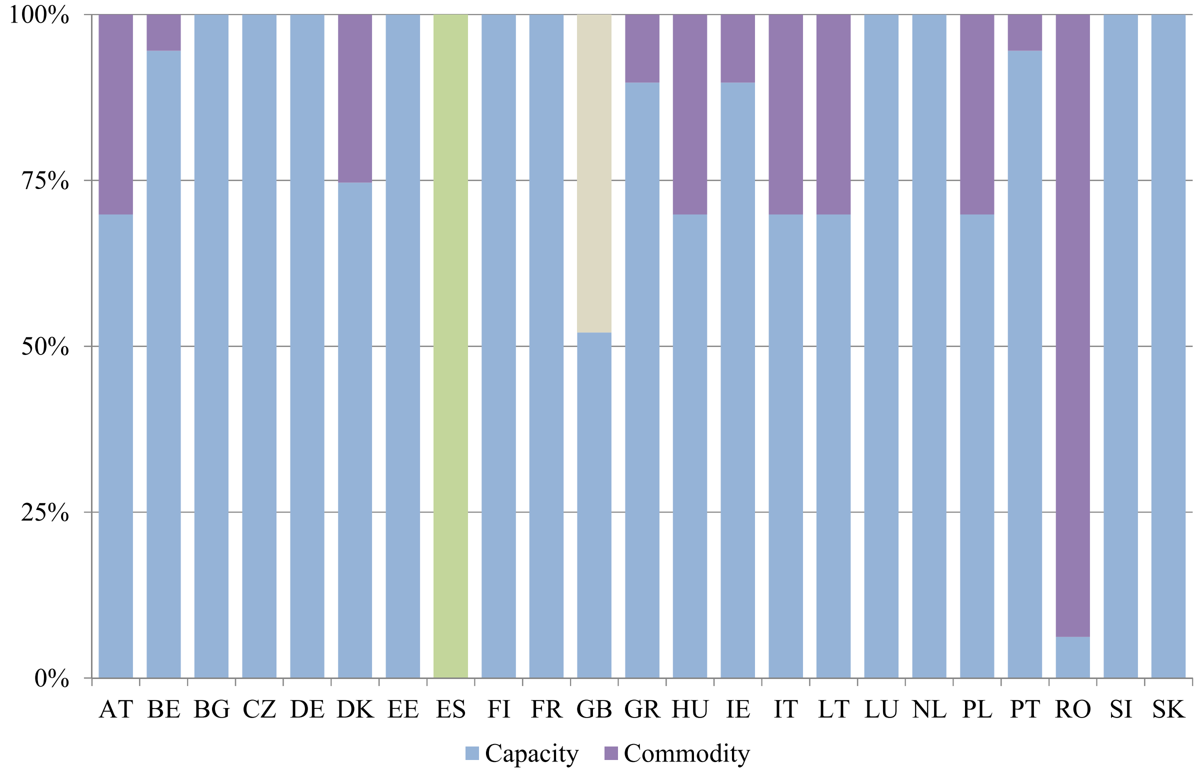
Several parties have indicated their concern regarding the use of different cost allocation methodologies between domestic and cross-border entry and exit points. The main concerns are that the some methodologies might result in excessive cross-subsidies between cross-border and domestic routes,[21] and might distort competition and reduce liquidity.[22] Many countries have reported treating cross-border flows the same way as domestic flows.[23] Spain and Hungary are two exceptions. In 2011, Spain priced cross-border transport at 70% of domestic transport. Hungary appears to base cross border cost allocation on the underlying costs, while the domestic network is based on costs necessary for reinforcement. Even where countries report the same approach for domestic and cross-border flows limited information has been provided to understand what this means in reality.[24]

[21] The THINK report describes cross-subsidisation when all entry points and all exit points are set the same (see THINK report, p. 45). However cross-subsidies could also occur in other cases.
[22] See for example KEMA/REKK report, p. 92.
[23] Internal information provided by the Agency.
[24] *Ibid.*

### Differences in the capacity-commodity split

TSOs generally recover their allowed costs through a mixture of capacity and commodity charges. Sometimes large differences in the split between capacity and commodity charges exist in MSs, and this is another mechanisms by which differences between cost allocation methodologies may lead to distortions between flows. Figure 6, which is taken from the THINK report, illustrates the range of the split between capacity and commodity charges over the EU.

**Figure 6: Split between capacity- and commodity-based components in gas transmission tariffs[25]**




Differences in the capacity/commodity split will in effect create different tariffs for different types of user. For example, suppose TSO B recovers all of its revenues via a capacity charge.[26] TSO C on the other hand recovers only 70% through a capacity charge[27] even though both TSOs have the same underlying costs. A user with a low load-factor would prefer the route through $TSO_C$, since it ships a relatively low level of commodity. A user with a high load-factor would prefer the route through $TSO_B$ (see Table 3 for example). Arguably this leads to excessive cross-subsidy between the low-load factor user and other types of user.

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25 Based on THINK report Figure 7, which in turn is sourced from the KEMA/REKK report. We have updated the split for Romania based on the Romanian official order for approving the transmission tariffs (ORDIN nr. 76 /27.08.2009).

26 As is the case in Austria, Denmark, Hungary, Italy, Lithuania and Poland (see Figure 6).

27 Recovery of 70% of costs through the capital charge is similar to the approach adopted in Bulgaria, the Czech Republic, Estonia, Finland, France, Luxembourg, the Netherlands, Slovenia and Slovakia (see Figure 6).

**Table 3: Impact of difference capacity: commodity splits**

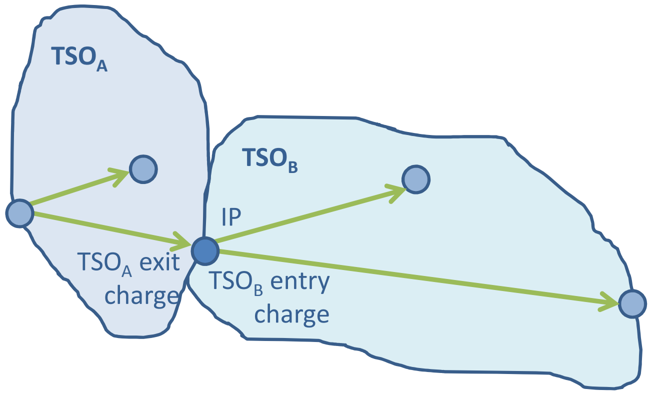
| | | | $TSO_B$ | | $TSO_C$ | |
|---|---|---|---|---|---|---|
| | | | cross-border route | domestic route | cross-border route | domestic route |
| Total capacity booked | [1] | Assumed | 1 | 1 | 1 | 1 |
| Total volumes transported | [2] | Assumed | 6,000 | 4,000 | 6,000 | 4,000 |
| Cost allocated to entry | [3] | Assumed | 5.0 | 2.5 | 5.0 | 2.5 |
| Costs allocated to exit | [4] | Assumed | 5.0 | 2.5 | 5.0 | 2.5 |
| % costs allocated to capacity | [5] | Assumed | 100% | 100% | 70% | 70% |
| % costs allocated to commodity | [6] | Assumed | 0% | 0% | 30% | 30% |
| Cost allocated to entry (capacity component) | [7] | [3]x[5] | 5.0 | 2.5 | 3.5 | 1.8 |
| Cost allocated to entry (commodity component) | [8] | [3]x[6] | 0.0 | 0.0 | 1.5 | 0.8 |
| Costs allocated to exit (capacity component) | [9] | [4]x[5] | 5.0 | 2.5 | 3.5 | 1.8 |
| Costs allocated to exit (commodity component) | [10] | [4]x[6] | 0.0 | 0.0 | 1.5 | 0.8 |
| Entry capacity tariff | [11] | See note | 3.8 | 3.8 | 2.6 | 2.6 |
| Entry cammodity tariff | [12] | See note | 0.00000 | 0.00000 | 0.00023 | 0.00023 |
| Exit capacity tariff | [13] | [9]/[1] | 5.0 | 2.5 | 3.5 | 1.8 |
| Exit commodity tariff | [14] | [10]/[2] | 0.00000 | 0.00000 | 0.00025 | 0.00019 |
| User 1 - low load factor | | | | | | |
| Load factor | [15] | Assumed | 3,000 | | 3,000 | |
| Tariff per unit volume | [16] | ([11]/[15]+[12]+[13]/[15]+[14])x1,000 | **2.9** | | **2.5** | |
| User 2 - high load factor | | | | | | |
| Load factor | [17] | Assumed | 8,000 | | 8,000 | |
| Tariff per unit volume | [18] | ([11]/[17]+[12]+[13]/[17]+[14])x1,000 | **1.1** | | **1.2** | |

Notes and sources:
[11]: Sum of [7] for domestic and cross-border routes divided by the sum of [1] for domestic and cross-border routes.
[12]: Sum of [8] for domestic and cross-border routes divided by the sum of [2] for domestic and cross-border routes.
[16]: ([11]/[15]+[12]+[13]/[15]+[14])x1,000
[18]: ([11]/[17]+[12]+[13]/[17]+[14])x1,000

### 4.2 *PROBLEM 2*: CONTAGION OF NON COST-REFLECTIVE PRICING

The previous section discussed distortions of trade routes because of the pricing of one transport route relative to another. However, inefficiencies could also arise from different pricing policies at a single IP (or VIP). For example, suppose that on one side of an IP was TSO A and on the other TSO B (see Figure 7). The total charge that the shipper faces from going from A to B is the exit charge of TSO A at the IP and the entry charge of TSO B. Suppose that TSO B tries to adopt a reference price which is in line with the costs that the IP entry point imposes on the system. But TSO A has a policy of allocating a large percentage of costs to IP exit points, so the total IP tariff is higher than a cost reflective charge.

**Figure 7: Example of different pricing policies at IPs**




The assignment of a relatively large percentage of costs by $TSO_A$ to the exit point could lead to fewer capacity bookings at that IP. This in turn affects the revenue recovery of $TSO_B$, who is able to sell less capacity than it otherwise would at the IP. $TSO_B$ could raise the price at the IP to recover the desired revenues – but this is likely to exacerbate the cost recovery problem at the IP. Alternatively, $TSO_B$ can try and recover the revenue shortfall from other IPs or exit points in its network. But this will compromise cost reflectivity by shifting revenue recovery away from the original IP to other entry-exit points. In this way a lack of cost-reflectivity in the reference price of one TSO at an IP can create a kind of 'contagion' effect, undermining cost-reflectivity in neighbouring TSOs reference prices.

The above type of scenario could arise when different cost allocation methodologies apply to domestic and cross-border routes. For instance, a market area could have a policy of allocating a higher percentage of the costs to the cross-border route to keep costs low for domestic consumers or to attract gas into their market area. For example, the Czech Republic, has low entry tariffs to "promote imports of gas and to enable entry of new shippers".[28] Member States who, like the Czech Republic, purposefully keep the entry IP tariffs low would need to push any entry IP costs not recovered by the IP entry tariffs to other entry/exit points, and may push these costs onto the exit IPs.

Where high exit IP tariffs result from compensating for lower entry IPs, the above problem may affect domestic production rather than cross-border flows within TSOA as the cross-border flows would benefit from the lower tariffs at the TSOA entry point.

To illustrate this point we return to our stylised example (depicted in Figure 7). We assume as before that in both TSOA and TSOB the costs of the cross-border route are €10 and the costs of the domestic route are €5. We also assume that in TSOB costs are allocated 50% to the entry points and 50% to the exit points. We show in Table 4 that, if TSOA also used this 50:50 cost allocation, a user would need to pay €8.8 for crossing from network A to B. If instead, TSOA allocated 90% of its cross-border route costs to the IP exit point, a user would need to pay a higher price of €12.8.[29] This consists of an exit tariff of €9.0 for $TSO_A$ and an entry tariff of €3.8 for $TSO_B$. The higher price as a

[28] Internal information provided by the Agency.

[29] We are not suggesting that a 50%/50% cost allocation would be cost-reflective while a 90%/10% allocation would not be cost-reflective. Rather we are trying to demonstrate the effect of shifting a higher proportion of costs to the IP exit point.

result of $TSO_A$'s cost allocation could put system users off from booking capacity at the IP to the detriment of $TSO_B$.

**Table 4: Example of non-cost-reflective pricing at IPs**

| | | | TSOA | | TSOB | | Amount paid to go from TSOA to TSOB |
|---|---|---|---|---|---|---|---|
| | | | cross-border route | domestic route | cross-border route | domestic route | |
| **Equal cost allocation between entry and exit** | | | | | | | |
| Capacity booked | [1] | Assumed | 1 | 1 | 1 | 1 | |
| Costs: | | | | | | | |
| Total | [2] | Assumed | 10 | 5 | 10 | 5 | |
| % allocated to entry | [3] | Assumed | 50% | 50% | 50% | 50% | |
| % allocated to exit | [4] | Assumed | 50% | 50% | 50% | 50% | |
| Allocated to entry | [5] | [2]x[3] | 5.0 | 2.5 | 5.0 | 2.5 | |
| Allocated to exit | [6] | [4]x[2] | 5.0 | 2.5 | 5.0 | 2.5 | |
| Entry tariff | [7] | See note | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 |
| Exit tariff | [8] | [6]/[1] | 5.0 | 2.5 | 5.0 | 2.5 | 5.0 |
| Total tariff | [9] | [7]+[8] | 8.8 | 6.3 | 8.8 | 6.3 | **8.8** |
| **TSOA high allocation to cross-border exit point** | | | | | | | |
| Capacity booked | [10] | Assumed | 1 | 1 | 1 | 1 | |
| Costs: | | | | | | | |
| Total | [11] | Assumed | 10 | 5 | 10 | 5 | |
| % allocated to entry | [12] | Assumed | 10% | 50% | 50% | 50% | |
| % allocated to exit | [13] | Assumed | 90% | 50% | 50% | 50% | |
| Allocated to entry | [14] | [11]x[12] | 1.0 | 2.5 | 5.0 | 2.5 | |
| Allocated to exit | [15] | [13]x[11] | 9.0 | 2.5 | 5.0 | 2.5 | |
| Entry tariff | [16] | See note | 1.8 | 1.8 | 3.8 | 3.8 | 3.8 |
| Exit tariff | [17] | [15]/[10] | 9.0 | 2.5 | 5.0 | 2.5 | 9.0 |
| Total tariff | [18] | [16]+[17] | 10.8 | 4.3 | 8.8 | 6.3 | **12.8** |

Notes and sources:

[7]: Sum of [5] for domestic and cross-border routes divided by the sum of [1] for domestic and cross-border routes.

[16]: Sum of [14] for domestic and cross-border routes divided by the sum of [10] for domestic and cross-border routes.

Another situation in which this type of potential problem may arise is when the same tariff applies to all IP exit points. In other words, when the costs allocated to IP exit points are socialised among the IP exit points. This type of tariff system applies, for example, in Belgium.[30] In this scenario, an exit point that had lower costs than average would have a tariff that is above its costs.

Capacity/commodity splits can also lead to lack of cost-reflectivity. The tariffs may not be sufficiently cost-reflective, if the commodity element of the tariff departs too far from the actual

30 Internal information provided by the Agency.

variable costs of the system. This could lead to inefficiencies. For example, a system user may have bought capacity, but decide not to flow gas cross-border if the commodity charge is more than the value of the cross-border trade. However, it would have been efficient to make the trade if its value is greater than the variable cost of transporting the gas.

**Recovery of allowed revenues**

In a tariff system with revenue regulation, tariffs for capacity are set so that when considering the *expected* purchases of capacity, TSOs will recover their allowed revenues. However, actual purchases of capacity can differ from expectations and so the TSOs might actually recover more or less than their allowed revenue over time. Some mechanism is required to ensure that a shortfall in revenue can be made up or excess revenues returned to network users. The mechanism chosen can further accentuate any departure from cost-reflectivity in the tariff system.

One mechanism for dealing with under or over-recovery of revenues would be to recover any shortfall in revenues from capacity charges at the entry or exit point at which the shortfall occurred by increasing the tariff at the entry or exit point. Similarly for over-recovery, the tariff at the entry or exit point would be reduced to offset the over-recovery. In this way, the cost allocated to the entry or exit point would be recovered by capacity booked at the entry/exit point. However, one concern with this approach is that if there has been under-recovery at a particular entry point, the tariff at that entry point would be increased in subsequent years which could lead to a reduction in capacity and further under-recovery.

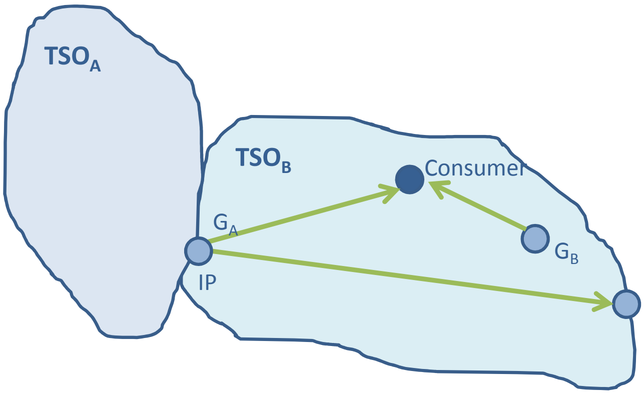
An alternative is for the TSO to recover revenue pro rata from all entry and exit points through a general uplift, or via a commodity charge. Again, differences in approaches to cost recovery can lead to differences in network tariffs that are not sufficiently cost reflective. The THINK study notes that correcting under-recovery of TSO revenues via a commodity charge "causes additional distortions in natural gas trade since the commodity charge does not reflect any short-run marginal cost of system operation."[31] On the other hand, recovering costs that were not recovered at one entry or exit point from other entry or exit points could reduce cost reflectivity.

### 4.3 *PROBLEM 3*: DISTORTION OF COMPETITION

We illustrate the problems that could arise with the simple case where a domestic source and a cross-border source of gas compete to serve the same consumer (Figure 8). The consumer is connected to TSO B's network and can be served from the domestic source at GB in B or from cross-border gas GA. TSO B allocates a significant amount of the actual costs of the route from the IP to the consumer to the entry tariff at the IP. In contrast, a relatively small amount of the network costs are allocated to the entry point at GB. This arrangement would give an unfair advantage to the domestic producer relative to cross-border flows.

[31] THINK report, p.45.

**Figure 8: Distortion of competition between domestic and cross-border gas supplies**




We illustrate this effect by returning to our example of a cross-border route with costs €10 and a domestic route (from IP) with of costs €5. We add to this example a route from the domestic production site at GB to the consumer which also has underlying costs of €5. We consider two different cost allocation scenarios (see

Table 5). In the first scenario, the costs for each route are allocated equally between the entry and exit points. In the second scenario, most costs (90%) for the route from the IP to the consumer are allocated to the IP entry point, while for the route from the domestic production point (GB) to the consumer only a small amount of the costs (10%) are allocated to the entry point. In our example, reducing the costs allocated to the domestic production reduces the tariff for this route from €5 to €3. The lower tariff could mean that supplies from TSOA are effectively subsidizing supplies from point GB. If the supplies from TSOA travelled through a number of market areas before reaching consumer and in each market area a high amount of costs were allocated to the cross-border route, then price pancaking could be an issue.

**Table 5: Example of distortion of competition**

| | | | TSOB Routes | | |
|---|---|---|---|---|---|
| | | | Cross-border route | IP to consumer | GB to consumer |
| **Same allocation for all routes** | | | | | |
| Capacity booked | [1] | Assumed | 1 | 1 | 1 |
| Costs: | | | | | |
| Total | [2] | Assumed | 10 | 5 | 5 |
| % allocated to entry | [3] | Assumed | 50% | 50% | 50% |
| % allocated to exit | [4] | Assumed | 50% | 50% | 50% |
| Allocated to entry | [5] | [2]x[3] | 5.0 | 2.5 | 2.5 |
| Allocated to exit | [6] | [4]x[2] | 5.0 | 2.5 | 2.5 |
| Entry tariff | [7] | See note | 3.8 | 3.8 | 2.5 |
| Exit tariff | [8] | [6]/[1] | 5.0 | 2.5 | 2.5 |
| Total tariff | [9] | [7]+[8] | 8.8 | 6.3 | 5.0 |
| **Low cost allocation for domestic production** | | | | | |
| Capacity booked | [10] | Assumed | 1 | 1 | 1 |
| Costs: | | | | | |
| Total | [11] | Assumed | 10 | 5 | 5 |
| % allocated to entry | [12] | Assumed | 50% | 90% | 10% |
| % allocated to exit | [13] | Assumed | 50% | 10% | 90% |
| Allocated to entry | [14] | [11]x[12] | 5.0 | 4.5 | 0.5 |
| Allocated to exit | [15] | [13]x[11] | 5.0 | 0.5 | 4.5 |
| Entry tariff | [16] | See note | 4.8 | 4.8 | 0.5 |
| Exit tariff | [17] | [15]/[10] | 5.0 | 2.5 | 2.5 |
| Total tariff | [18] | [16]+[17] | 9.8 | 7.3 | 3.0 |

Notes and sources:

[7]: Sum of [5] for domestic and cross-border routes divided by the sum of [1] for domestic and cross-border routes.

[16]: Sum of [14] for domestic and cross-border routes divided by the sum of [10] for domestic and cross-border routes.

### 4.4 *PROBLEM 4*: DISTORTIONS FOR SHORT-TERM CROSS-BORDER TRADING

The CAM NC envisages that TSOs will also offer shorter term capacity products at IPs by auction with a reserve price.[32] The network code does not specify how the reserve price should be set for these shorter term products. Many TSOs currently offer short-term capacity products often at a significant premium to annual capacity.[33]

32 CAM NC Article 4.2 and 7.

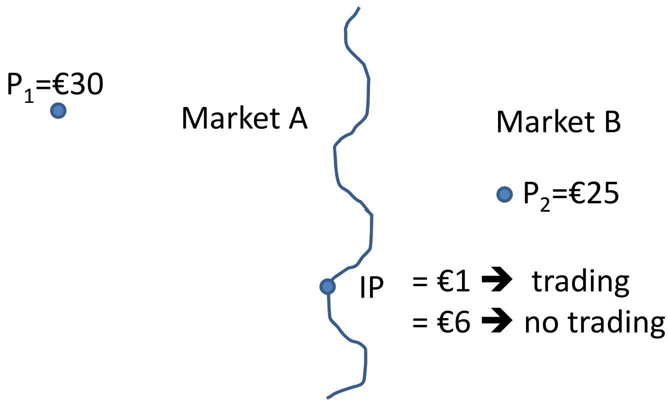
33 See KEMA/REKK report, p. II and also internal information provided by the Agency.

With congestion – that is, where demand for capacity exceeds supply – it is likely that short-term prices resulting from auctions will exceed the reserve price, and may approximate or exceed the long-term price. The issue with the pricing of short-term capacity arises when there is no congestion, and the reserve price determines the price of capacity. Accordingly the discussion below assumes that there is no congestion.

As discussed in section 3.1.2, in an efficient market we would expect differences in the cost of gas to drive cross-border gas trading. However, different approaches in the pricing of short-term capacity can play a significant role in driving short-term cross-border trade. If the methodology for setting short-term capacity reserve prices is not harmonized, one could regard the different patterns of cross-border trade that emerge as a result of tariff decisions as 'distorted', relative to a situation in which all networks harmonised their decisions regarding short-term pricing.

For short-term capacity, cost-reflective tariffs could mean basing the tariffs on the short-run marginal costs that short-term trades impose on the network. In most cases, absent congestion, this would mean a tariff at or close to zero. Alternatively, cost-reflective could mean long-term average costs of the system (as could be used to set the annual regulated price). Setting the short-term tariff, including any commodity charge, as SRMC rather than LTAC would present many more trading opportunities. Figure 9 shows an example of two adjoining markets. In market A the gas price is €30/MWh while in market B the gas price is €25/MWh. In this example, flows from long-term capacity are not sufficient to equalise the price differences between the two market areas – additional flows using short-term capacity are required to arbitrage away the price differences. We take the case that the short-run marginal costs of transporting from B to A is €1/MWh. If the price of short-term capacity at IP is set at €1/MWh, trading would occur between hub A and B. If however, the short-term capacity is priced at the LTAC of €6/MWh, no trading would occur between the hubs. It follows that if two TSOs set the short-term price at the SRMC there could be lots of trading between countries. However, there may be far less trading when the TSOs set the price at long-term average costs. However, as we note in section 3.1.2 a lack of harmonisation on short-term pricing may simply represent different choices regarding a complex trade-off, rather than an avoidable distortion of the market.

**Figure 9: Pricing of short-term capacity**



Only a small number of TSOs price short-term capacity at SRMC. Many TSOs have reported pricing of day-ahead capacity at somewhere in the range of 0.9 to 13.4 times the pro-rated price of annual capacity.[34] The question is really then whether these high prices for short-term capacity are preventing short-term trades that would otherwise occur. In addition, different pricing levels could also be distorting short-term flows. A trader in Germany with spare spot gas could sell at the TTF, Zeebrugge or CEGH spot markets but the trader's decision of where to sell the gas could be affected by the multiples applied to short-term entry capacity in the relevant countries. In Belgium, the multiple could be anywhere between 1.3 and 5, in the Netherlands it is in the range 1.825 to 7.3. The multiple in Austria is 2.[35]

Selling short-term capacity at a discount can also create cost-recovery issues. For example, the THINK study reports on the experience in the UK where setting the reserve price at a discount relative to long-term capacity has seen longer term capacity bookings being replaced by short-term bookings with an associated increase in the commodity charges.[36] Since in GB short-term capacity is sold at a discount to the current annual reference price, a shift to short-term booking is generally associated with revenue under-recovery at the entry points, which must be compensated by a higher commodity (£/MWh) charge. Hence, a decrease in the percentage of allowed revenue recovered by capacity charges in GB is indicative of a revenue under-recovery problem.[37]

Figure 10 illustrates the situation in the GB gas market between gas years 2004/05 and 2012/13. The blue line shows the percentage of the allowed entry revenues that have been recovered from capacity charges have declined from about 80% before 2008/09 to a projected 30% for 2012/13. Since waiting to book short-term capacity has the risk that no capacity will be left to buy, we would expect the risk of congestion to be a key factor in determining to what extent shippers will try and move towards short-term capacity when it is discounted below the current long-term price. It is noteworthy that the step change in the percentage of revenues recovered from capacity charges has occurred after the start of the economic crisis in 2008/09. One explanation for the increase in the commodity charge is that shippers have shifted to 'cheaper'[38] short-term capacity partly because they are more confident that the there is little chance of congestion because of reduced gas demand.

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34 Internal information provided by the Agency.

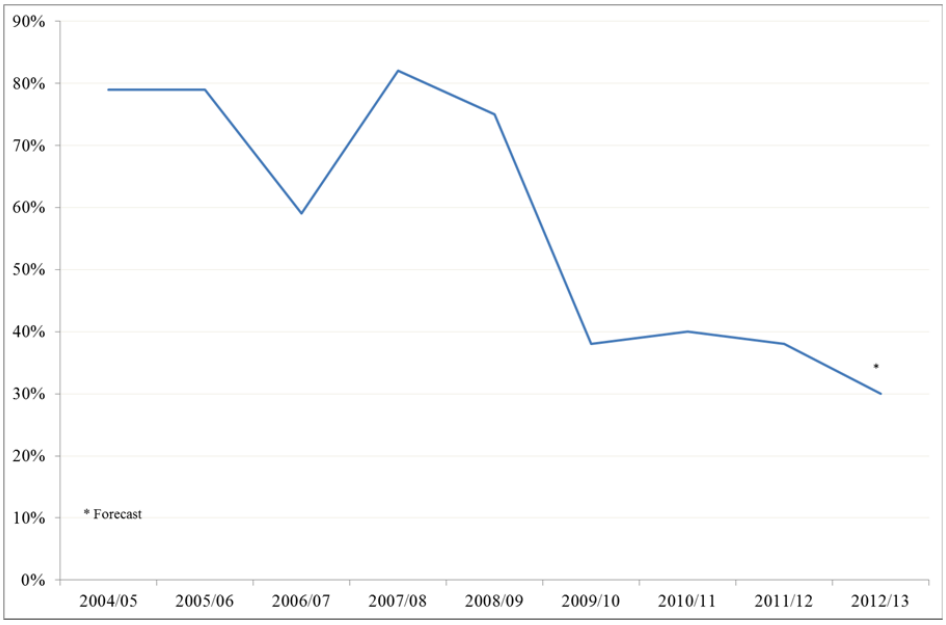
35 *Ibid.*

36 The THINK report, p. 45. However, Ofgem disagreed with this assessment, and noted that shippers face much more complex trade-offs than the size of the short-term discount. Short-term capacity prices are not necessarily cheaper than long-term capacity prices because purchases of long-term capacity pay the price at the time of purchase (i.e. the price is not indexed to inflation). Therefore although today short-term capacity is purchased at a discount to current long-term prices, the short-term prices may not be lower than long-term prices at the time of purchase. For instance, long-term prices back in 2003 when 15-year capacity auctions began are lower than the current prices for day-ahead capacity at some points in GB. At the time of booking long-term capacity, the shipper would need to decide whether it thought short-term capacity in the future would be cheaper than existing prices for long-term capacity.

37 However, Ofgem recently rejected a proposal to remove the short-term discount because it did not consider it would better achieve the charging methodology objectives of avoiding undue discrimination and promoting competition and efficiency, indicating that they do not perceive a problem with short-term discounts. See Ofgem document "Modification Proposal NTS GCM 'Removal of NTS Daily Entry Capacity Reserve Price Discounts'", 30 July 2010.

38 However, the short-term capacity price in GB may still be higher than the payable price for long-term capacity.

**Figure 10: Percentage of allowed entry revenue recovered via capacity charges**




A similar experience has also been reported for Germany.[39] Currently in Germany the reserve price for day-ahead capacity auctions is set to zero. However, the German transportation capacity platform TRAC-X would like the regulator to set an above zero reserve price. TRAC-X has reported that for the majority of short-term capacity the price does not rise above the zero reserve price. In April 2012, only 7% of day-ahead capacity was priced above zero. Network users are moving away from long-term capacity and are instead obtaining capacity on a daily basis for free. TRAC-X expects this flight to short-term to get worse in the future as parties who continue to purchase long-term capacity will be at a disadvantage. TRAC-X also recognizes the loss in investment signals as short-term capacity purchases replace long-term purchases. TRAC-X has also reported that the minimum price for other auctions will need to be increased in order to compensate for the losses.

Apart from the effects of the economic crisis, the Security of Supply Regulation could create a more structural lack of congestion, since gas networks should be sized to deal with peak demand even in the event of an outage.[40] An absence of congestion could be the default condition for IPs in the EU, which would mean that it would be difficult to recovery costs with a zero reserve price for short-term capacity.

### 4.5 *Problem 5*: Pricing of non-physical backhaul capacity and interruptible products

Article 14 (1)(b) of the Gas Regulation clearly sets out that the price of interruptible capacity should "reflect the probability of interruption". From the initial responses to the Agency Consultation

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[39] European Spot Gas Markets, 01/06/2012, p. 1 & 9.

[40] Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply, Article 6.

Document, there appears to be agreement between many parties that a discount should apply to interruptible products that reflects the risk of interruption. Despite the clarification in the Gas Regulation regarding the principal of pricing interruptible capacity, differences in pricing policies can and do still occur.

The manner in which the discount for backhaul and interruptible products should be applied has not been specified in the Gas Regulation. Differences could therefore arise from the way in which the probability of interruption is calculated and also whether the discount will be applied when the tariffs are set or whether it will apply retroactively after interruptions have occurred, via a refund. The fundamental problem with respect to the pricing of interruptible capacity is a potential lack of cost reflectivity, which could lead to a less an efficient use of the network and could undermine cross-border trade.

Currently, a number of TSOs price interruptible capacity by applying a discount to the firm capacity price that represents the probability of interruption. However, the discounts vary widely. For instance, in Italy, the discounts are between 10-20% while in the Czech Republic the discount can be as high as 75%. In Austria, a mechanism is used where users are compensated for interruption rather than being offered a discount in advance. Differences in the level of discounts for interruptible service could be cost reflective if the probability of interruption varied among the networks. However, differences in discounts may arise from use of different methodologies to estimate the appropriate discounts.

There is no provision in the Gas Regulation requiring the offer of non-physical backhaul capacity. The THINK study reports that as of 2011, "[n]on-physical backhaul capacity is only offered by the minority of TSOs."[41] However, we note that based on ENTSOG's May 2012 Capacity Map, about 90% of cross-border IPs claimed to offer backhaul.

In their responses to the Agency's public consultation on the scope and main policy options for the Consultation Document, many parties suggested that users contracting non-physical backhaul capacity should be charged no more than administrative costs or even zero if administrative costs are close to zero.[42] However, others feel that such a level of pricing would not be cost reflective, and that back-haul users should pay their 'fair share' for the pipeline which has made the backhaul trade possible.[43]

Accordingly, the key problem in the context of this study is the lack of consistency in the pricing of interruptible capacity and backhaul capacity, and an inconsistency in the availability of the latter.[44] The two products are closely linked, because a backhaul product is by definition interruptible, since it

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41 See THINK report p. 39.

42 Public responses to the Consultation Document can be found at: http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Stakeholder_involvement/Public_consultatations/Closed_Public_Consultations/PC-06/Responses%20to%20PC-061

43 Given that TSOs are not currently bound to offer a backhaul tariff, some have wondered if setting low backhaul tariffs could provide a disincentive to TSOs to offer backhaul. However, we note that as long as the price of backhaul covers the marginal costs of the service, then the TSO has an incentive to offer it.

44 See THINK report, p. 40.

requires a forward flow nomination to occur. Without the forward flow nomination – which is outside of the TSOs control – the TSO cannot program a non-physical backhaul flow.

Backhaul flows create two types of savings. They can postpone the need for network expansion by relieving congestion in the direction of the physical flow. The postponement of costs creates a positive present-value saving. Second, backhaul flows have a more immediate effect of savings variable costs by reducing flows. Non-physical backhaul capacity can also enhance cross-border trade by providing players with access to markets that they otherwise would not have. Market players can take advantage of arbitrage opportunities which will improve liquidity and help develop competition. However, the benefits provided by backhaul capacity will be lost or attenuated if the capacity is priced inappropriately.[45]

In its study on Methodologies for Gas Transmission Networks, KEMA/REKK reported that backhaul capacity prices that are well above 'costs' would prevent efficient arbitrage between neighbouring markets and may contribute to a sub-optimal use of the network.[46] Inappropriate pricing of backhauls could also distort flows in neighbouring networks as it can inhibit trades that could occur in the presence of appropriate backhaul pricing.

One potential problem with not harmonising backhaul pricing is that inappropriate pricing of backhauls in one Member State may inhibit the use of backhaul in other Member States. A backhaul route could span several Member States, in which case the pricing in each Member State would affect the take-up of the backhaul. For example suppose that a shipper would like to sell gas that originates in France at the CEGH spot market in Austria, and that to complete this transaction the user must purchase "backhaul" capacity along the route from France to Austria via Germany. France prices backhaul at 20% of forward flow, but both Germany and Austria charge higher prices for backhaul (between 50 and 85% of the forward flow price).[47] These higher backhaul prices could make the backhaul less attractive to the shipper and sufficient for the user to decide against performing the backhaul transaction.

### 4.6 ***PROBLEM 6*: DIFFERENT TREATMENT OF GAS STORAGE TARIFFS**

TSOs currently differ in their treatment of entry and exit tariffs for gas storage facilities. Gas storage is somewhat different from other entry-exit points, because it is not a net source of demand or supply but rather shifts consumption from one period to another. Suppose that gas must travel some distance from the border to a centre of demand, and that a storage facility is built close to the demand centre. Absent the storage, the TSO will have to size the import pipeline to supply the peak demand. With gas storage, the pipeline can be sized for the average demand, and the storage can make up the differences between the actual and average demand. In this way the storage allows a reduction in the size and cost of the required import pipeline. Some TSOs might set tariffs for storages recognising this special feature, while others may treat it as just another entry and exit point.

45 ACER problem identification report, p. 12.
46 See KEMA/REKK report, p. VI.
47 ERGEG document "Analysis of National Transmission Structure".

Differences in the approach to setting storage tariffs could have negatively affect two policy objectives. First, it could lead to inefficient investments. Developers will prefer to build storages in market areas which apply a 'special' entry-exit tariff regime for gas storage but this may not be where storage is needed most. As a result, TSOs may need to build larger capacity pipelines because storages would not be attracted to the most efficient locations. However, the effect of tariffs on storage citing decisions must be put into context. Unlike power plants, storage facilities have a more limited choice as to suitable sites, because they need to be built at the site of a salt cavern or depleted gas or oil field.

Second, some tariffs for gas storage may not be sufficiently cost-reflective, if they do not recognise the effect that storage has on investments and the cost of the network outlined in the first paragraph of this section.

### 4.7 *PROBLEM 7*: LACK OF TRANSPARENCY

Much progress has been made on this issue of transparency since the start of the liberalisation of the gas market. The initial objectives with respect to transparency were to do with the publication of tariffs, so that at least price discrimination could be avoided – that is, the TSO cannot charge different users different prices for the same service depending on their willingness to pay.

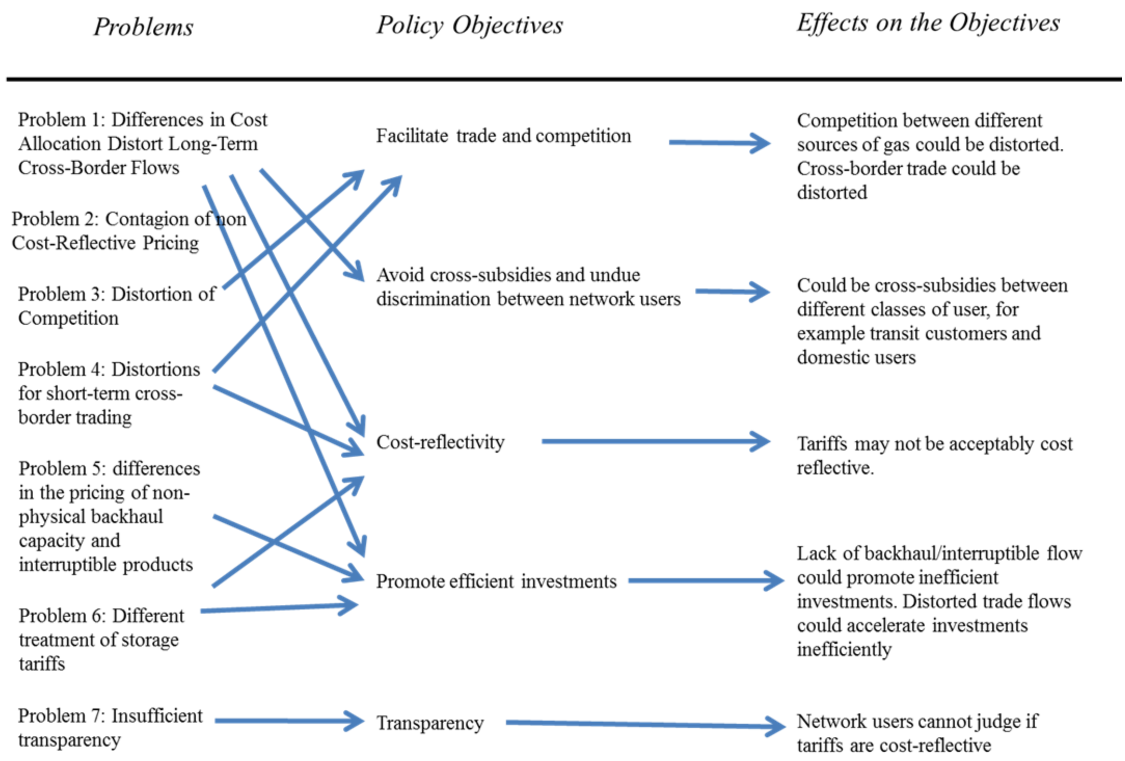
However, while TSOs and NRAs publish tariffs and some details of the calculation of allowed revenues, many TSOs do not publish sufficient detail to allow shippers to understand how the reference price at each entry and exit point was derived. One notable exception is NGG, which makes available a detailed model that allows shippers to understand how NGG derives tariffs for each point. Most TSOs do not provide this level of detail. Among other things, this lack of transparency makes it difficult for the network users to assess whether tariffs are sufficiently cost-reflective.

Network users may also find it difficult to estimate how transportation tariffs might evolve in the future, and how network congestion is expected to develop over time. This could make it difficult for network users to plan investments which are partially dependent on future tariffs, or to make long-term commitments to capacity. While users could attempt to make their own tariff forecasts, the TSO is in a unique position to make a forecast because it has an overview of all the technical constraints of the system, and also has access to capacity booking data for all users.

### 4.8 RELATIONSHIP BETWEEN PROBLEMS AND POLICY OBJECTIVES

In Figure 11 below we summarize the relationship between the first four problems identified and the objectives – specifically the arrows indicate which problems affect which objectives. To the right we summarize the main negative effect that one or more problems have for achieving each policy objective.

**Figure 11: Problem 'tree'; relationship between identified problems, policy objectives and the effects on the objectives**



# 5 POLICY OPTIONS

Table 5 in the Agency's consultation document on the Framework Guidelines sets out a number of policy options which could address the problems identified. We describe the policy options below. Implicitly every policy option includes a Business as Usual or BAU scenario where the current state of affairs is unchanged. In the assessment of the impacts of the policy options we will always compare to the baseline of the BAU scenario.

## 5.1 REFERENCE PRICE SETTING FOR FIRM ANNUAL CAPACITY PRODUCTS

As described in section 4.1, there are a large number of ways in which TSOs can allocate their target revenues to entry and exit points. Sections 1.1 and 1.2 of the Consultation Document describe both the principals of using historical or average costs as a basis and the different ways of combining average costs or LRMC methodologies to arrive at a set of entry-exit tariffs.

The spectrum of Policy Options to evaluate could include:

1) Strict harmonization of tariff methodologies – this would mean that the FG lays out a detailed approach to calculating reference prices, given an allowed revenue. The methodology would be set out in a network code and would be mandatory for all EU TSOs. The exact approach could be for example:

   a) An individual cost-based approach: cost references for entry and exit points would be calculated based on the estimated costs of infrastructure associated with the entry or exit point. When assets are used both for cross-border and domestic entry and exit points, a non-discriminatory rule would be used to allocate the costs between the two types of uses and users.

   b) Matrix Cost methodology: the entry and exit regulated tariff at cross-border interconnection points and at domestic points would be calculated so as to minimise the difference between network charges paid by agents and the estimated costs assigned to the different entry-exit paths. The combination of 'path costs' – being the cost of going from entry point A to exit point B for all combinations of entry and exit points – would be represented in a matrix with as many rows as exit points and as many columns as entry points. The entry-exit tariffs would then be calculated by minimising the sum of the squares of the differences between the cost and price (being the sum of the entry and exit tariff – of every path.

   c) Distance to the virtual point: the "virtual point", which is a reference node or theoretical location to which gas travels, would be determined through the minimisation of the distance to entry/exit points weighted by respective transmission capacities. The costs are then allocated to the different entry/exit points based on the distance to the virtual point. This approach is currently applied in Belgium for example.

d) Equalisation approach: this is also known as a 'postal' tariff. The TSO simply divides the allowed revenue by the total capacity sold at all entry and exit points of a system to arrive at a single tariff for all entry and exit points.

e) Determination of cross-border and domestic target revenues based on LRMC: the reference price is set by calculating the cost of providing an additional unit of capacity – the LRMC – for all cross-border and domestic entry and exit points. The TSOs total allowed revenues, based on historical costs – are then split into two 'target revenue' pots – one for cross-border and one for domestic – by pro-rating according to the LRMCs.

2) Partial Harmonisation. Instead of strict harmonization, the FG could try and reduce the degree of differentiation in cost allocation between MSs. Partial harmonization could come in two different formats:

a) Binding Rules. The FG, and subsequently the network code, would aim to prohibit the most extreme types of cost allocation, for example where there is an effort to push costs to border points which could not easily be justified by an analysis of system use. Alternatively some TSOs/NRAs might be pushing costs the other way, to domestic entry and exit points, so as to lower cross border tariffs. While stopping short of a detailed tariff methodology, the rules could for example lay out practices and principles for cost allocation to entry and exit points that would lead to some degree of harmonization. The binding rules could also lay down guidelines for the maximum acceptable allocation of costs to entry and exit tariffs, by specifying methodologies for allocating costs to different 'cost envelopes' or 'accounting pools'.

b) Specify maximum acceptable deviations. Under this approach the FG, and subsequently the network code, would lay out a standardized tariff methodology for calculating reference prices that would be used as a benchmark. The network code would then specify that the TSOs chosen tariff methodology should not result in reference prices which deviate by more than XX% from the standard or 'benchmark' methodology.[48] The value of XX% could be set pragmatically, by first seeing how many tariff as currently set deviate from the proposed benchmark, and then setting XX% to get a trade -off between the amount that tariffs would need to change and the level of harmonisation.

3) Harmonisation of the tariffs themselves at an IP, rather than the underlying tariff methodologies. Some experts have noted correctly that, even with the same tariff methodologies, tariffs at other side of an IP will likely differ because allowed revenues will differ. If differences in tariffs are preventing the achievement of the objectives, then harmonising the tariffs, rather than the tariff methodologies, could be one policy option.

We note that Article 5.1 (10) of the CAM NC contemplates the creation of Virtual Interconnection Points (VIPs). This means that the TSOs would offer capacity from one market area to another, but not specify which physical point would be used to transport the gas. In our view the

[48] This idea is based on a proposal by Sergio Ascari of the Florence School of Regulation submitted to the ACER Gas Tariffs Expert Group Meeting on May 4th, 2012.

adoption of VIPs does not present any special issues with respect to the reference price for long-term capacity products, or any other aspect of tariff harmonisation.

The value of a capacity product is in transporting gas from one market areas to another. A rational shipper should be indifferent between the physical path used to transport the gas, and so the use of VIPs should not affect pricing. If IPs were physical and not virtual, the value of several IPs connecting the same market areas should still be identical. Capacity between the IPs should be completely fungible – if one of the IPs became congested, the TSOs could simply move gas flow to one of the less congested IPs.

### 5.2 Reserve prices for short-term capacity

We evaluate two broad following policy options with respect to short-term pricing:

1) Full harmonisation of short-term capacity prices. The network code would specify the methodology for setting the price of short-term capacity that would be mandatory for all EU TSOs. The TSO at the exit side of the IP and the TSO at the entry side of an IP would have to follow the same approach to setting the short-term capacity, so that the price methodology would be harmonised across the IP.[49] The methodology could be based on a number of possibilities:
    a) Pricing short-term products proportionally to the yearly reference price. Capacity would be priced in direct proportion to the annual capacity with respect to time. For instance, a one day capacity product would be priced at 1/365 of the price of an annual capacity product, and a quarterly product at 1/4. Seasonal factors could also be applied. Seasonal factors should result in the *average* price across a year for daily capacity being 1/365 multiplied by the annual capacity price, even if daily –capacity prices are sometimes higher or lower than this level at certain times of year.
    b) Pricing at the short-run marginal cost level. Reserve price for quarterly and monthly capacity will be priced in proportion to annual capacity as in 1) above, but daily and within-day capacity will be priced at SRMC.
    c) Pricing with multipliers lower than one for short-term products. Reserve price for quarterly and monthly capacity will be priced in proportion to annual capacity as in 1) above. Daily and within-day capacity will be priced at annual price multiplied by a multiplier less than one. Seasonal factors can also be applied. Seasonal factors should result in the average price across all quarterly or monthly products in the year being the same as an annual capacity product.
    d) Pricing with multipliers higher than one for short-term products. The shorter the duration of the capacity product the higher the multiplier will be. Seasonal factors can also be applied. Seasonal factors should result in the average price being the same as a flat longer-term peak capacity booking.
2) Application of Binding Rules. The network code would specify the binding rules that would apply to the price setting of short-term capacity.

[49] Although of course the exit reference price will generally not be the same as the entry reference price at the IP, because of differences in allowable revenues.

a) The rules could for example lay out under what circumstances zero reserve prices may be appropriate, and when zero reserve prices could lead to cost under-recovery without any offsetting benefits such as increased trade. Similarly, the rules could lay out the maximum prices for short-term capacity.

b) The rules would apply to both sides of an IP. For example, if no congestion was expected at an IP, so that a zero reserve price was not appropriate, the TSO at the exit side of the IP and the TSO at the entry side of an IP would have to follow the same approach to setting the short-term capacity – which could be for example that the short-term price is XX% of the pro-rated annual reference price.

### 5.3 Interruptible capacity

We evaluate the following options for the pricing of interruptible capacity:

1) Auction with an ex ante discount. Set the reserve price for interruptible capacity to zero and let the auction decide on what the market value for interruptible capacity.

2) Ex post refunds. Set the reserve price for interruptible capacity to the same price as firm capacity and offer network users refunds when interruptions occur. The refunds could be set by reference to the market price of gas at the time of the interruption, specifically the difference between the price in the upstream market area and the downstream market area, plus an administratively determined bid-offer spread. Alternatively, if market prices were not available, the refund could be set by reference to the annual capacity price. In either case the refund would be capped at the original price paid for the interruptible capacity.

Offering network users refunds when interruption occur would mean TSOs would bear the risk of interruption. If instead the discount is decided in advance as under 1) above, then it is the shippers that bear the risk of actual interruptions being different to forecasts.

### 5.4 Non-physical backhaul

We propose to consider pricing of non-physical backhaul capacity separately and include the following four options:

1) Sell backhaul capacity by auction and set the reserve price to recover only administrative costs.

2) As above, but set the reserve price to zero.

3) Set the reserve price for backhaul capacity to reflect both the risk of interruption and the estimated cost savings offered by backhauls through avoided variable costs (i.e. a zero commodity charge) and deferred network expansion if applicable.

4) Price backhaul in the same way as interruptible capacity. That is, there would be a discount offered according to the probability of interruption using the same methodology as is applied to forward interruptible capacity. For cases where the probability of interruption was very small,

this would result in backhaul prices which are just slightly lower than firm forward capacity at the same network point.

### 5.5 PAYABLE PRICE FOR LONG-TERM CAPACITY

While it is agreed that long-term capacity will be auctioned, there remain a number of options regarding how the price to be paid (the payable price) for existing cross-border capacity (IPs) will evolve over time. Updates to the payable price are particularly important when the user pays for the capacity a substantial amount of time after buying the capacity.[50] For instance, during a 10 year period the regulated tariff, and the allowed revenues of the TSO, will change due to a new regulatory period for tariffs. The payable price could track changes in the regulated tariff, in which case the capacity buyer bears the price risk. Alternatively the byer could pay a price fixed – in real terms – for the duration of the contract, in which case the TSO, or perhaps other network users, bear the risk that the price will diverge from the allowed revenues.

Specifically, we consider four options for the payable price. The Agency presents four options which are:

1) Fixed nominal premium: The payable price consists of a premium on or discount to the reference price, which is fixed in nominal terms for the duration of the contract. While the premium is fixed in nominal terms, the total amount payable will vary according to changes in the regulated reference price;

2) Fixed real premium: as above, but the premium or discount is updated for inflation, and so remains constant in real terms. While the premium is fixed in real terms, the total amount payable will vary according to changes in the regulated reference price;

3) Fixed nominal price. The payable price is fixed in nominal terms for the whole duration of the capacity contract. Note that in this case, the TSO would still need to set a reserve price for the capacity, and that the reserve price should be related to the reference price. Specifically, so as to ensure revenue recover the TSO should determine a nominal price which, over the duration of the capacity contract, has the same present value as the expected reference prices over the contract duration. This means that if reference prices are expected to increase in nominal terms over the contract duration, the reserve payable price in the auction would need to be *above* the year 0 reference price, to account for the subsequent increases in the reference price. If the reserve payable price was the same as the year 0 reference price, this policy option would be guaranteed to result in revenue under recovery if the reference price was expected to increase in nominal terms, which would clearly be undesirable.

4) Inflation-indexed clearing price: The payable price is set as the auction price updated annually for inflation. Again, the payable reserve price may need to be above the year 0 reference price, but the use of inflation-indexation could mean that this is not required. For example if the

[50] This issue becomes much less relevant if capacity is only sold for one or two year durations. For example for a one-year capacity contract, all the alternatives discussed should give roughly the same reference price.

reference price was expected to stay constant in real terms, the reserve payable price could be the same as the year 0 reference price without creating a structural under-recovery problem.

### 5.6 RECOVERY OF ALLOWED COSTS

Section 4.2 of the Consultation Document discusses three options for the recovery of allowed revenues when required for NRAs applying revenue regulation: Use of regulatory accounts; adjustment of allowed revenues through capacity based revenue recovery charges; and adjustment of allowed revenues through commodity charges.[51]

In our view, the use of regulatory accounts is not a separate option, but is rather a required feature under any regime that allows the NRA to track the differences between the actual and required revenues over time. The issue is then whether to use capacity or commodity based recovery charges, and how to set these.

We consider the following two policy options:

1) A harmonised policy approach for the timing of the recovery of allowed revenues. That is the policy could state that a shortfall in revenues must always be recovered in the following year.

2) A harmonised policy approach for the method of recovery of allowed revenues. We break this down further into two policy dimensions;

    a) Specifying that recovery should be via a commodity charge or a capacity charge, or some combination.

    b) Specifying whether cost recovery should be ‘broad’ so spread over all entry and exit points, or ‘narrow’ which means cost recovery is focused on the point or perhaps group of points where the under recovery took place.

### 5.7 HARMONISATION OF SETTING OF ENTRY-EXIT TARIFFS FOR GAS STORAGE

To address the issues identified in section 4.6, a harmonised tariff policy for storage tariffs could be adopted. The harmonised policy would aim to set entry and exit tariffs for gas storage in a consistent way, which reflect the benefits to the network which gas storages can bring.

### 5.8 INCREASING TRANSPARENCY REQUIREMENTS

The FG could specify that every TSO must publish sufficient information to allow network users to understand how the reference price or tariff at each entry or exit point was derived from the allowed revenues. The TSO should either publish a numerical model which describes the tariff derivation, or else provide a sufficiently detailed description that user could build such a model. Users should be able to understand the main inputs to the model so that they can independently investigate the effect of changes in key assumptions on the tariffs.

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51 Of course another option would be to simply not recover the missing allowed revenue. We do not consider this because it is not good regulatory policy to promise revenue to the TSO and then disallow them ex post.

TSOs could also publish data that would allow users to understand how tariffs are likely to evolve in future, if the model included a projection of tariffs for the following 5-10 years and highlighted the assumptions on which the forecast tariffs depended. This would likely include expected system flows, details of major capital investments and the expected development of operating costs.

### 5.9 MERGERS OF ENTRY AND EXIT ZONES

One of the current themes of EU gas market policy is that the current entry-exit zones (or market areas), which are largely national in scope, may not always be optimal from the point of view of creating liquidity. In some cases it may be beneficial to merge two or more entry-exit zones to create a market area which is capable of creating a liquid gas market.

This policy involves a trade-off. On the one hand, a larger market area will contain more opportunities for trading gas without having to buy cross-border capacity. On the other hand, a larger market area reduces the ability to create cost reflective gas transport tariffs. This is because, as the market area becomes ‘larger’ there are less entry-exit tariffs relative to the possible number of gas transport paths, and so each entry/exit tariff must try and approximate a larger number of possible journeys on the network.

For example, consider that a point-to-point tariff system can set a tariff for each transaction path – but liquidity is relatively low because there is no entry-exit system. Shipper must transport gas to a particular point on the network to trade it. Now consider a very simply entry-exit system with four entry/exit points labelled A, B, C and D. There four entry/exit tariffs the NRA can set, and 12 possible journeys, from A to B/C/D, from B to A/C/D etc. more generally, for a system with N entry/exit points, there will be (N-1).N possible journeys, which for a larger system is approximately $N^2$, and N entry/exit points. The ratio of the possible journeys to entry and exit points is therefore approximately N, the number of entry/exit points. As the system grows, the entry/exit tariffs are trying to approximate the costs of an increasing number of possible transaction paths, and cost reflectivity is compromised. In the most extreme case, suppose the entire U was combined in an entry/exit system. Liquidity would be very high, but any form of cost reflectivity in tariffs would be lost.

The above discussion highlights that the trade-off between cost reflectivity and liquidity is fundamental. It is independent of whatever tariff system is chosen. Therefore we do not see scope for policy options within the tariff harmonisation FG that will address this issue.

A merged entry-exit zone, which will contain two or more TSOs, will of course require that the tariffs recover the allowed revenues of all the TSOs. This will mean that the TSOs will need to develop systems to re-allocate the revenues, since the revenues collected by one TSO on its system is unlikely to match its allowed revenues. However, the principals for the setting of the tariffs within the merged entry-exit zone, and between the merged entry-exit zone and other zones, are the same as for other unmerged zones. Therefore it seems that no special rules or treatment is required for the development of tariffs for merged entry-exit zones.

# 6 ASSESSMENT OF IMPACTS

## 6.1 ASSESSMENT CRITERIA

We assess policy options against the following set of criteria:

1. Ability to solve problems associated with the policy area: To what extent would the policy option address the relevant problems identified in Section 4?

2. Feasibility and cost: How feasible or costly is the option, noting that feasibility includes elements cost, speed of implementation, compliance with existing regulatory systems and welfare effects?

3. Risk: What is the risk that the policy option could give rise to new perhaps unforeseen problems in the gas market?

4. Proportionality: Does the option go beyond what is needed to achieve the objectives and solve the problems?

5. Subsidiarity: could action by Member States achieve a similar result to the Policy option? Or can the results be better achieved by action by the Community?

In some cases we evaluate each policy option separately. However, for some policy options discussing all of the options together (in parallel) can facilitate the evaluation.

As well as discussing how each policy option performs against these criteria, we also compare the alternative policies of a particular 'policy area' in a table. The policy areas correspond to the headings in section 5, but for the avoidance of doubt they are:

- Reference Price Setting for Firm Annual Capacity Products
- Reserve Prices for Short-term capacity
- Pricing of Interruptible Capacity
- Pricing of Non-Physical Backhaul
- Payable Price for long-term capacity
- Methods for the recovery of allowed costs
- Pricing of entry-exit tariffs for gas storage
- Transparency Requirements

For ease of comparison and decision making, we give each policy option a score for each of the assessment criteria – the higher the score the more closely the policy option conforms with the criteria. We score the 'ability to solve' problems out of 25, and other criteria out of 10 – this reflects our view that the ability to solve problems should be the main criteria for evaluating the solutions. We also include the 'Business as Usual' or BAU scenario in each table. By default the BAU scenario scores relatively low for the ability to solve problems, but the gets a high score for feasibility and cost (because it is the existing solution). BAU will generally score well on risk (because there are unlikely to be unintended consequences, although there is a risk that the problem could get worse with no action). BAU also score well on proportionality, since taking no action cannot be dis-proportional to the problem at hand. Intuitively, the BAU scenario does little or nothing to solve the current problems, but on the other hand is low cost, free to implement and unlikely to have any unintended consequences.

We recognise that these scores are subjective, but we feel that they are nevertheless useful for ranking and evaluating the options. Note that we do not include the ‘subsidiarity’ criteria in the evaluation tables – this is because for any policy area, either action is required at the Community level or it is not, and therefore all policy options would achieve the same score under this criteria. However, adding to the table a criterion where all policy options score the same does not help us chose between the policy options. Hence we exclude this criterion from the evaluation tables.

To keep the analysis tractable and as clear as possible, we assess the policy areas separately. However, we of course recognise that there are strong inter-relationships between many of the policy areas. In particular many of the policy options will have strong interactions with revenue under or over recovery. For example, the use of SRMC for the pricing of short-term capacity products would likely lead to a greater role for cost recovery mechanisms. We highlight these relationships in the following analysis.

## 6.2 REFERENCE PRICE SETTING FOR FIRM ANNUAL CAPACITY PRODUCTS

**Strict Harmonisation**

1. Ability to solve problems associated with the policy area:

   a. The relevant Problems here are numbers 1, 2 and 3. The problems are mainly associated with a reference price that is not sufficiently cost reflective.

   b. As we noted in section 3.1, no reference price methodology can be fully cost reflective for each gas transport transaction or journey – there will always be some cross-subsidy.

   c. However, a strict harmonisation policy could eliminate some practices which most people would not accept as sufficiently cost-reflective – for example allocating ‘excessive’ costs to the IPs, or subsidising domestic exit points with higher charges on border exit points.

   d. A suitable cost-reflective harmonised tariff methodology would solve problems 2 and 3. Both problems are caused by the TSO allocating ‘excessive’ costs to IPs.

   e. It is not clear that a fully harmonised reference methodology would fully solve problem 1, which relates to a lack of ‘locational signals’, in the sense that shippers use the system in a way which minimises *future* costs. Even in a harmonised system, shippers would send gas through the old, cheap, system even if that system had a the largest future costs of expansion, so that it would be better to use a more expensive neighbouring system which had lower expansion costs. This issue could be addressed if the harmonised tariff system used some form of LRMC to set tariffs for IPs which face competition from other routes. However, the use of pure i.e. un-scaled LRMC faces its own problems. For example LRMC is always forward looking, and so does not allocate the historical costs of the system to those that caused them. Hence *without the use of long-term contracts*, pure LRMC will not be cost reflective – many costs will have to be socialised. Pure LRMC tariffs are also unstable, because they change significantly as soon as the network is expanded.

f. However, a harmonised system of tariffs would mitigate problem 1, in that it would not be possible for a TSO to allocate a very high or very low percentage of allowed revenues to IPs. This would avoid either taxing cross-border flows for the benefit of domestic users or cross-subsiding cross-border flows with high tariffs at domestic entry and exit points.

g. We should also recognise that even where the reference price methodologies were harmonised, tariffs would differ across TSOs, because different TSOs have different allowed revenues. Most obviously, some networks are old and therefore revenue requirements are less. While revenue setting is outside of the scope of the FGs, it is important to recognise that differences in allowed revenues will not lead to equal reference prices. (Score 20/10)

2. Feasibility and cost: Full harmonisation would be technically feasible. However, it would involve large costs of several types.

    a. First would be the direct costs – most TSOs would need to re-calculate their tariffs, and this would include updating software and documentation.

    b. There would be adjustment costs for users, especially for users who experience a large change in tariff as a result of harmonisation. In extreme cases such changes could result in financial distress for some firms.

    c. Other costs could include possible legal action especially by users who lose out, or who need to annul or change supply contracts. Buyers and sellers may not be able to agree who bears the new costs. Users could challenge details of the methodology or perhaps the entire legal basis for harmonisation.

    d. Finally, there is the cost that Member States would lose the flexibility for gas tariffs to perform other, national policy goals. Some policy goals may not be consistent with EU law and specifically the Gas Regulation – for example a transit country may try and shift excessive costs to IP exit points and away from domestic exit points so as to lower domestic gas prices. However, other policy goals may be perfectly legitimate. For example some Member States have selected 'postalised' exit tariffs, because they feel this is socially desirable. Other Member States may wish to send local locational systems, perhaps to encourage industry to locate in one area or another for employment or environmental reasons. Under a fully harmonised system MSs would lose an instrument of national policy. (Score 3/10)

3. Risk: The main risk is that the harmonised tariff methodology chosen would not in fact be the one that best achieves the policy objectives, at least not in all MSs. In essence, this is the 'all the eggs in one basket risk'. It would also be difficult to agree changes in the tariff methodology, once it was agreed. Presumably any such change would require a large degree of consensus. The risk is that MSs that somehow 'lose out' from the suggested change would block it. Without the ability to update the methodology, even a methodology which starts out optimal could become sub-optimal over time.
4. Proportionality: The proposal to completely harmonise tariff methodologies does not seem proportional to the magnitude of the problems described.
5. Subsidiarity: Action at the Community level is required, in particular to deal with distortions of cross-border flow.

**Partial Harmonisation**

1. Ability to solve problems associated with the policy area:
    a. In reality, 'partial harmonisation' covers a wide spectrum of policy options. For example very strict binding rules would be very similar in effect to a fully harmonised methodology. The same is true for a policy that only allowed very small deviations from the 'benchmark' methodology. Conversely, a lose set of binding rules or a policy that allowed wide deviations from the benchmark methodology would be similar to the BAU scenario. Here we evaluate a policy that is somewhere in the middle of these two extremes. The assumption is that the policy would eliminate any cost allocation methodologies that were not acceptably cost-reflective, recognising that full cost reflectivity is not possible. Hence the 'Guidelines' would in fact be binding rules.
    b. The ability of partial harmonisation to solve the problems identified is in our view similar to the full harmonisation policy. Given the remaining differences that would result from differences in allowed revenues between TSOs, it is hard to believe that the additional level of tariff convergence that would result from full harmonisation would make a substantial difference to solving the problems identified.
    c. Hence we give both types of partial harmonisation – being a binding rules approach and a benchmark methodology approach – the same score of 16/25.
2. Feasibility and cost: with respect to the binding rules, the main feasibility issue we see is developing suitably precise guidelines which could cover all of the existing tariff systems in the EU, and that would still be cost-reflective.
    a. For example, the binding rules could say that 'TSOs are not allowed to recover less than 30% of revenues from domestic exit points'. But in some transit systems it might be more cost-reflective to recover only 20% of revenues from domestic exit points. Developing prescriptive uniform guidelines that eliminate non-cost reflective tariffs for all tariff systems would be a challenge.

b. The alternative 'benchmark methodology' policy option does not suffer from this problem. Because it is a methodology it can be applied to any system – if the cost-reflective answer is to collect 20% of revenues from domestic exit points, then the benchmark methodology should give this answer.

c. The costs of this option of course depend on the extent of the harmonisation. Accordingly, the advantage of this solution is that the degree of harmonisation can be chosen pragmatically so as to achieve a suitable balance between costs and perceived benefits. This is in contrast to the 'all or nothing' approach of full harmonisation. The level of harmonisation could be chosen so that many TSOs whose reference price methodologies are acceptably cost reflective do not have to change their tariff methodology, or only need to make minor adjustments. All TSOs/NRAs would need to check their tariff methodology against the binding rules or guidelines, but these costs should be relatively minor compared to the cost of full harmonisation.

3. Risk: One risk is that the binding rules are not well drafted, or actually make some systems less cost-reflective. For the benchmark methodology, the risk is that the wrong benchmark is chosen. However, because the binding rules will allow some flexibility, or the TSOs will be allowed to deviate from the benchmark tariff methodology, this option is less risky than a full harmonisation approach.

4. Proportionality: The option seems proportional to the level of the problems identified.

5. Subsidiarity: Subsidiarity: Action at the Community level is required, in particular to deal with distortions of cross-border flow.

**Harmonisation of Tariff levels, not methodologies**

1. Ability to solve problems associated with the policy area:

   a. The central idea behind this option is that if it is differences in tariffs that are causing flow 'distortions', then why not simply equalise the tariffs? However, the problems that tariff harmonisation is trying to solve are not that tariffs are different in absolute levels. Rather the problems stem from inadequate cost reflectivity in some tariff methodologies and excessive levels of cross-subsidy. As perhaps becomes clearer when one considers the feasibility of a uniform tariff level, it seems that in some cases the uniform tariff would be less, rather than more, cost reflective.

2. Feasibility and cost:

   a. The first issue is what a uniform tariff would mean in reality. For example, it might be desirable to try and equalise the tariffs for all the various ways to get from point A to point D as in Figure 2. This would leave the shipper indifferent between the routes. However:

      i. It is not clear that setting the tariffs for alternative route at an equal level would be cost reflective. Perhaps in many cases one route should be cheaper than another.

ii. It is unlikely to be possible to find a set of tariffs which equalises the price of all combinations of routes throughout the EU, unless one simply set the same tariff for every IP point in the EU. However, this would not be cost reflective.

iii. Even if one decided to try and set the same tariff for all IPs, it is not obvious how to arrive at what that tariff should be. One could for example set a common IP tariff which in aggregate minimised the differences between current IP tariffs and the new common tariff. But this could still create big changes for the IP tariffs of some MSs. TSOs would have to recover their remaining revenue from other entry and exit points, which would mainly be domestic exit points. If the new uniform IP tariff was much lower than the existing IP, domestic users would face sharp tariff increases, and vice versa.

b. The imposition of a uniform tariff would likely involve similar costs to the option of the full harmonisation of the tariff methodology. As in that case, TSOs would need to change their tariff methodology to deal with the new uniform IP tariff, and there would be associated costs for system users as they have to adjust their contracts.

c. Harmonisation of tariff levels could also result in cross-subsidies between users in a country with, for example, a well maintained network and users in a country with a poorly maintained network in another country.

3. Risk: As implied above, there is a risk that a uniform IP tariff could be less cost reflective than current tariff levels, which could exacerbate the problems identified.
4. Proportionality: Imposing a uniform IP tariff does not seem to be proportional. It would severely constrain national tariff policy while not delivering clear benefits.
5. Subsidiarity: Subsidiarity: Action at the Community level is required, in particular to deal with distortions of cross-border flow.

**Summary of Reference Price Policy Options**

Table 6 summarises our evaluation of the different policy options with respect to harmonisation of reference price setting.

**Table 6: Evaluation of the Reference Price Policy options**

| | Full Harmonisation | Partial Harmonisation - binding rules | Partial Harmonisation – benchmark methodology | Tariff Harmonisation | BAU |
|---|---|---|---|---|---|
| **Ability to solve the problems** | 20/25 | 16/25 | 16/25 | 12/25 | 1/25 |
| **Feasibility and cost** | 3/10 | 5/10 | 7/10 | 3/10 | 9/10 |
| **Risk** | 5/10 | 6/10 | 7/10 | 3/10 | 9/10 |
| **Proportionality** | 2/10 | 8/10 | 8/10 | 2/10 | 10/10 |
| **Total** | 30/55 | 35/55 | 37/55 | 20/55 | 29/55 |

We recommend the standard methodology specifies that the capacity/commodity split should approximately reflect fixed and variable costs respectively. This will avoid distorting decisions by capacity holders by ensuring that the marginal price of using capacity reflects the marginal cost of doing so as closely as possible. This is an area where cost-reflectivity is relatively easy to establish, since variable costs can be traced to items such as compressor fuel. Allocations that differ widely from this recommendation would not be cost reflective, and could discourage efficient trading.

### 6.3 Reserve Price for Short-term capacity

1. Ability to solve problems associated with the policy area:
   a. We evaluate the two policy options of:
      i. Full harmonisation of the pricing of short-term capacity;
         1. The policy options present several different methods for setting short-term tariffs.
      ii. Binding rules, which would set out which minimum and maximum limits should apply to the price of short-term capacity at which times.
   b. With regards to full harmonisation, a number of policy options have been put forward.
      i. One option is to apply a premium to the short-term price, in the sense that the price of daily capacity would be the price of annual capacity divided by 365, multiplied by a factor greater than one. Proponents of this approach could argue that this type of charging is cost-reflective. For example, imagine two users that book the same amount of capacity but for different durations. The first user books annual capacity while the second user has purchased a day’s worth of capacity for use during the peak day. Both transactions have the same investment costs need. The same amount of pipeline capacity has to be built for both users whether the capacity is used for a day or a year.

ii. To be cost reflective some people could argue that the short-term user would need to pay a higher tariff to recover the same costs as the annual users. If users only pay the annual tariff divided by 365, but only book the capacity for 50% of the time, they may not be paying their share of the costs of the network.[52]

iii. The CAM network code attempts to account for this case through its use of so-called 'revenue equivalence'. Under revenue equivalence, a TSO's anticipated revenues should be unaffected by the duration over which users contract capacity. Whether the users fulfill their capacity needs through purchasing annual capacity, shorter term capacity or a mix of both, the TSO should be indifferent with respect the anticipated revenues. It follows from this that short-term during peak periods should be priced above long-term capacity to offset the shorter time periods across which capacity is booked, at least in winter months.

iv. However a permanent 'premium' for short-term products could be viewed as "a penalty on short-term trade".[53] One could question whether high premiums reasonably reflect costs.[54] Pricing above long-term pricing may also be discriminatory if new entrants are particularly reliant on short-term capacity to access a gas market.[55] A premium on short-term capacity might also lead to hoarding of long-term capacity in preference to short-term purchase – although the CMP proposals should go some way towards mitigating this issue.[56] One concern has been the arbitrary use of multipliers applied to the long-term price.[57] Another concern is that a premium on short-term capacity could lead to over-recovery of revenues and thus windfall profits.[58] However, over-recovery could only result if demand for short-term exceeds expectations which does not fit with the above concern that a premium could cause hoarding of long-term capacity instead.

c. Another option that has been put forward is to price short-term capacity at marginal cost, which in many cases could be close to zero. On the one hand, allowing low or zero prices for short-term capacity will encourage efficient trading. On the other hand, for IPs that are not expected to be congested, low or zero reserve prices for short-term capacity could lead to cost recovery problems, if there is a flight to booking low-cost short-term capacity. Attempting to recover missing revenues could in itself undermine policy objectives such as cost reflectivity, if users of the IP pay little for it and the costs are instead recovered from other users.

d. Another issue that has been raised is that with no or zero reserve prices there could be a 'price war' for short-term capacity on routes where there is price to price competition.

52 THINK report, p. 47.
53 THINK report, p. 45.
54 ACER problem identification report, p. 12.
55 *Ibid.*
56 *Ibid.* See also THINK report, p. 45
57 See ACER initial responses report, p. 12.
58 See ACER initial responses report, p. 12.

TSOs may compete with one another on price so as to gain market share, leading to a zero reserve price, unless instructed by the NRA that this was not allowed.

e. Accordingly, it seems that TSOs and/or NRAs could legitimately apply different policy options for the price of short-term capacity, depending on:

   i. Their expectations for congestion at the IP;

   ii. The desire to encourage short-term trading and price arbitrage;

   iii. Their willingness to accept some risk of revenue under-recovery at the IP.

f. For example, if a TSO expected some episodes of congestion, then it could allow low or zero reserve prices for short-term capacity. Costs could be recovered when congestion occurred. However, if the TSO did not expect an IP to be congested, then it could apply a reserve price based on a multiple of the annual reference price. The exact level again depends on a policy choice. TSOs and NRAs may wish to encourage more short-term trade and price arbitrage even if this comes at the expense of cost recovery, and for this reason there could be a legitimate reason to set lower multipliers, including multipliers less than one. For example a TSO with an illiquid market might wish to encourage trading with a neighbouring liquid market by setting a low short-term tariff, even if these means costs at the IP will need to be recovered from other network users.

g. The question then remains – should the FG set a maximum price for short-term capacity, relative to the annual reference price? We note that reference price for annual capacity in any case sets an implicit limit for the price of short-term capacity (absent congestion). If the multiplier for short-term capacity becomes too high, then users will eventually switch to buying longer term capacity. However, to avoid 'excessive' pricing of short-term capacity, the FG could set some limits. We recommend that the FG endorse the 'revenue equivalence' principal. The price of daily capacity could exceed the pro-rated price of long-term capacity at certain times – by which we mean the annual price divided by 365 – the average daily price over a year should not exceed the annual price of capacity. If it did, the TSO could end up in recovering more than its costs, at the risk of discouraging short-term trading.

h. The above considerations imply that a full harmonisation of short-term capacity pricing may not be required, because differences in national circumstances could generate legitimate reasons for setting different tariffs. Rather, a binding rules approach which sets out which pricing policy could be best under which circumstances could avoid situations where there is excessive under-recovery at certain IPs with no offsetting benefits. Accordingly we score the full harmonisation lower (10/25) than the binding rules approach (20/25).

2. Feasibility and cost:

a. Full harmonisation is relatively simple to implement – the policy options already describe several alternative methods of pricing short-term capacity.

b. Developing binding rules would be more difficult, because it would rely on subjective judgements as to, for example, when zero pricing is allowed and when it is not. Developing rules that apply to all situations and yet are specific enough to be effective could be a challenge.

c. For this reason we give the binding rules approach a lower score on feasibility (6/10) that the full harmonisation approach (8/10).

3. Risk: The risk is that any uniform solution imposed on MSs would not achieve the correct trade-off between the desire to encourage trading and cost recovery on the other (hence a risk score of 3/10). In contrast, a binding rules approach appears to have relatively little risk (8/10).

4. Proportionality: A solution based on full harmonisation would likely go beyond what is required. Full harmonisation would also in effect rule out mechanisms such as implicit allocation of IP capacity which rely on zero price differences, and therefore an implied zero price of IP capacity, at times when there is no congestion. Hence we score full harmonisation at 3/10. A binding rules approach could be applied at relative low cost to avoid some of the issues identified above (score 8/10).

5. Subsidiarity: Appropriate action seems justified at the Community level.

**Table 7: Evaluation of short-term capacity pricing options**

| | Full harmonisation | Binding rules | BAU |
|---|---|---|---|
| **Ability to solve the problems** | 10/25 | 20/25 | 2/25 |
| **Feasibility and cost** | 8/10 | 6/10 | 9/10 |
| **Risk** | 3/10 | 8/10 | 9/10 |
| **Proportionality** | 3/10 | 8/10 | 10/10 |
| **Total** | 24/55 | 42/55 | 30/55 |

## 6.4 Interruptible capacity

**Ex-ante discounts, zero reserve price**

1. Ability to solve problems associated with the policy area:

a. Competitive auctions with a zero reserve price should be able to determine the market price for the service, thereby solving the problem of excessive pricing for interruptible capacity.

b. There should be no cost recovery issues from a zero reserve price, since interruptible capacity will only be sold after all firm capacity (which recovers the allowed revenues) is sold.

c. A co-ordinated approach to pricing interruptible capacity would avoid TSOs applying different discounts for interruption at either side of an IP when the probability and consequences of interruption are the same, so that logically the same pricing should apply.

2. Feasibility and cost:

   a. The auction mechanisms would likely be designed to sell a fixed quantity of interruptible capacity – this quantity would be determined administratively. The TSO would need to publish sufficient information on previous flows and interruptions at relevant points to enable auction participants to form a view on the probability of interruption.

   b. Incremental costs would be relatively small, since the CAM NC requires that TSOs run auctions for other types of capacity product.

3. Risk: Failure to publish sufficient information could still result in inefficient pricing of interruptible products.

4. Proportionality: The option only intervenes in a relatively narrow of tariff policy, and so seems proportional.

5. Subsidiarity: Action at the Community level is required because the problem affects cross-border flows.

**Ex post refunds**

6. Ability to solve problems associated with the policy area:

   a. This solution is similar to the previous solution discussed above, and will therefore be as successful in addressing the problems. The main difference is that in this case the risk of interruptions is shifted onto the TSO. That is, if the actual level of interruptions is higher than expected, the TSO will pay a larger discount. This is in contrast to *ex ante* pricing where, if interruptions are higher than expected the shippers do not receive any additional refunds.

   b. This option would require a methodology to establish the level of refund for a given level of interruption, recognising that even a small chance of interruption can have a significant effect on the value of capacity. Various reasonable methods are possible. For example, the method could specify that the value of the capacity is in effect zero at e.g. a 10% frequency of interruption, and use a linear scale to price the capacity for interruption frequencies between 10% and 0%. Alternative, the cost of interruption could be based on gas prices in the connected market. For example it would be reasonable to suppose that the cost of interruption is that the interrupted shipper would need to buy gas in the downstream market at a higher price than in the upstream market.

7. Feasibility and cost: Again this option would require a pricing methodology to calculate the refunds that would be given according to interruptions which occurred. The methodology could be almost identical to the harmonised pricing methodology – the only difference is that the final

price is determined *ex post* according to the actual level of interruptions, rather than *ex ante* according to the expected level of interruptions.

a. The methodology would need to specify that the refund could not exceed the amount originally paid for the interruptible capacity.

b. Costs would be similar to the other options discussed.

8. Risk:

a. There is a risk that, since the TSO bears the risk of interruptions, TSOs could perhaps try and reduce the probability of interruptions by limiting the quantity of interruptible capacity offered. On the other hand the TSO would then lose out on revenues from the sale of interruptible capacity. However, given that TSOs are in general revenue neutral, some form of incentive scheme may be required to ensure that the TSO makes the correct trade-off between the risk of interruption and the quantity of interruptible capacity offered.

b. Similarly, there is a risk that the chosen refund methodology does not adequately reflect the actual cost of interruptions. Again, this risk could be mitigated by an adequate consultation process that allows TSOs and others to propose the best methodology for the calculation of the costs of interruption.

9. Proportionality: The option only intervenes in a relatively narrow of tariff policy, and so seems proportional.

10. Subsidiarity: Action at the Community level is required because the problem affects cross-border flows.

Table 8 below summarises our evaluation of the different policy options for the pricing of interruptible capacity.

**Table 8: Evaluation of interruptible capacity pricing options**

| | Ex-ante price reduction | Ex post refunds | BAU |
|---|---|---|---|
| **Ability to solve the problems** | 20/25 | 20/25 | 1/25 |
| **Feasibility and cost** | 8/10 | 6/10 | 9/10 |
| **Risk** | 8/10 | 5/10 | 9/10 |
| **Proportionality** | 9/10 | 9/10 | 10/10 |
| **Total** | 45/55 | 40/55 | 29/55 |

### 6.5 NON-PHYSICAL BACKHAUL

1. Ability to solve problems associated with the policy area:

   a. Which policy best meets the objectives, especially that of cost-reflectivity, depends on how one thinks backhaul should be priced. One could summarise the debate on backhaul pricing as being divided into two views.

   b. The first view we could summarise as a 'service view'. That is, network users are paying for a service and the price should reflect the service they get. In the case of backhaul, if the backhaul product is interruptible, then the price of backhaul should be priced in exactly the same way as a forward flow with the same probability of interruption. That the gas is not physically flowing in a particular direction should not affect the price of the service.

   c. The second view could be classified as an 'incentives approach'. Under this view, backhaul flows have the potential to reduce variable and perhaps fixed costs for the networks, and so network users should be given incentives to make backhaul flows so that these benefits can be realised. This view of backhaul pricing would imply discounting a backhaul flow relative to the price of a forward flow, over and above the discount given for the interruptible or conditional nature of the backhaul flow.

   d. In more detail, the concern of the 'incentives approach' is that backhaul discounts which are 'too low' will deter backhaul flows and increase the costs of the network.

      i. The benefits of backhaul flows should accrue to users of forward capacity. Suppose that the booked forward flow is 10 units, and there is a back haul flow of 2 so that the actual forward flow is 8 units. Since the TSO is now dividing the variable costs of flowing 8 units over a booked 10 units, the variable cost per unit should decrease for the forward flow because of the backhaul. Similarly, if backhaul defers investments, then forward flows should experience lower capacity tariffs than would have been the case absent backhaul.

      ii. Suppose also that a backhaul flow resulted in variable cost and deferred capex savings with a total present value of €1/MWh. Any tariff which fails to pay the backhaul flow less than the €1/MWh could result in a situation where the backhaul shipper decides not to flow, and the benefit will be lost. That is, anything less than a *negative* backhaul charge could lead to an inefficient outcome, in the sense that by paying some of the savings to the shipper providing the backhaul flow both forward shippers and the backhaul shipper would be better off.

      iii. In reality, a negative charge could be problematic for both political and practical reasons. To receive the payment, the shipper would be obliged to supply gas at all times. Such an obligation could be difficult to enforce.

   e. The discussion above does suggest that, according to the 'incentives approach', it would be efficient to set backhaul charges at a very low level. This favours the auction of backhaul capacity with reserve prices set at either zero or at the administrative cost level.

f. However, one potential counter argument to low or zero backhaul tariffs is that they could be considered discriminatory.

   i. The argument for low or zero cost is based on the idea that backhaul users create little cost or may even save the system money.

   ii. However, some forward capacity users could also claim that their particular transaction saves the system money, or at least costs less than the price attributed to that transactions.

   iii. It could be discriminatory to develop a specific tariff methodology for backhaul which reflects 100% of the savings of backhaul, if a similar methodology is not applied to other network users for forward flow.

   iv. Any backhaul tariff methodology must be compatible with the approach taking to setting other entry and exit tariffs in terms of cost reflectivity. Since forward tariffs can never be completely cost-reflective, it would seem discriminatory to develop

g. Therefore while a low or zero cost option may be cost reflective, it also risks being discriminatory.

h. Moreover, zero backhaul tariffs could be extremely volatile. If flows change direction frequently, shippers could be faced with tariffs that swing from 0% to 100% of the forward tariffs and back again. Having a smaller backhaul discount would moderate this effect.

i. Unfortunately the objectives in section 3 do not offer much guidance with regard to the choice of the ‘service view’ of backhaul pricing and the incentives view. Both could be regarded as being broadly cost reflective and non-discriminatory. On balance, while we recognise the validity of the service view of backhaul tariffs, we think that some additional discount for backhaul would contribute more strongly to the policy objective of efficient investments, since backhaul flows could potentially reduce or defer the need for network investment.

j. Based on the arguments above, we give policy options with a low or zero price, and policy options that apply a discount only for interruptibility, a lower score (between 10 and 12/25) than the policy option which reflects the savings from backhaul but without applying a zero price (18/25). We give the latter policy the highest score because it seems to strike the best balance between cost-reflectively, non-discrimination and promoting efficient investment.

2. Feasibility and cost:

   a. There do not seem to be any major difficulties in developing a price for backhaul which is based on an estimate of administrative costs. Clearly the case of backhaul priced at zero is trivial. However, a policy where the price of backhaul was based on the forward price less a discount for the projected cost savings would be more complex. The parties would need to agree both the effect of the backhaul flows on future investments, and the discount rate to apply to reach a present value of the cost savings. These aspects could make the calculation of a backhaul tariff calculated in this way more subjective – hence this options score 4/10 whereas the others score between 7-8/10). The option where backhaul capacity is priced as interruptible capacity, but with no other discount, is again relatively simple since it would just adopt the methodology for measuring the cost of interruptions as is applied for pricing (forward flow) interruptible capacity.

b. Incremental costs of implementing this option should be relatively small. The change in the backhaul pricing methodology could be introduced at a suitable time, for example at the start of the next price control period for example, to minimise costs.

3. Risk: The main risk seems to be that the harmonised backhaul pricing methodology does not discount the backhaul tariff sufficiently, so that the inefficiency identified in the problem is not sufficiently resolved, or that pricing is discriminatory. Since this is a fine balance, all off the options score relatively low for risk (5/10) except for the option which applies some discount for backhaul but not a low or zero price, which gets 7/10. Note that in this case we give the BAU scenario a score of 5/10 for risk, because with no action there is a risk that backhaul problems could get worse over time as gas flows in the EU continue to change.

4. Proportionality: The option only intervenes in a relatively narrow of tariff policy, and so seems proportional. All options get a similar score for proportionality.

5. Subsidiarity: Action at the Community level is required because the problem affects cross-border flows.

Table 9 below summarises the evaluation of the various non-physical backhaul options, based on the discussion above.

**Table 9: Evaluation of backhaul options**

| | Zero Price | Administrative Costs | Discount which reflect interrubtibility and savings | Backhaul as interruptible | BAU |
|---|---|---|---|---|---|
| **Ability to solve the problems** | 12/25 | 12/25 | 18/25 | 10/25 | 2/25 |
| **Feasibility and cost** | 8/10 | 7/10 | 4/10 | 8/10 | 9/10 |
| **Risk** | 5/10 | 5/10 | 7/10 | 5/10 | 5/10 |
| **Proportionality** | 9/10 | 9/10 | 9/10 | 9/10 | 10/10 |
| **Total** | 34/55 | 33/55 | 38/55 | 32/55 | 26/55 |

### 6.6 Payable Price for Long-Term Capacity

1. Ability to solve problems associated with the policy area:

   a. Section 5.1 of the CAM NC specifies that IP capacity must be sold as a bundled 'hub-to-hub' product. This means that TSOs on either side of the border would need to agree a common payable price mechanisms for the capacity.

      i. One potential argument for harmonisation of the payable price at IPs is that it would avoid the need for TSOs to reach a separate agreement with each neighbouring TSO on the payable price. It would also avoid several alternative payable price mechanisms existing at different IPs. For example a TSO may have agreed a fixed nominal price with one TSO and an inflation-indexed premium to the regulated tariff with another IP.

      ii. This existence of several alternative mechanisms for the payable price could increase the complexity of the regulatory regime and make the market more complicated for shippers.

   b. However, it is not clear if this problem is very severe. TSOs will already have to co-operate on many other aspects related to the sale of the IP capacity, for example establishing a joint nomination procedure for capacity. Harmonisation makes the market easier for network users to manage. But on the other hand network users must deal with many complex issues, and differences in the payable price at IPs seems to be a factor that would be manageable, if perhaps undesirable.

   c. Another potential issue is whether differences in the price of long-term capacity and annual capacity at the same IP could create a 'competitive distortion'. For example, suppose that the regulated annual capacity charge at an IP is €1/MWh. For the same IP, a TSO had sold long-term capacity 10 years ago at a nominal price that is not indexed, and the price after

10 years is €0.7/MWh. Does this give the shipper with the long-term capacity an unfair competitive advantage?

d. The answer is that it does not, for two reasons:

   i. It may be tempting to think that the shipper with the long-term capacity could undercut the other shipper by €0.3/MWh, being the difference between the prices that they are paying for capacity, and that this is a source of 'unfair' competitive advantage. However, the opportunity cost of the capacity is the same for both shippers. In other words, both shippers could sell their capacity on the secondary market for the prevailing secondary market price, and this is the price that a rational shipper would consider when pricing its gas. Suppose the market price for capacity at the time was €1/MWh. The shipper with long-term capacity must consider that it could sell its capacity at a profit of €0.3/MWh. It must factor in this potential 'lost profit' whenever it uses the capacity to sell transport and gas. Hence, differences in the price that the shippers were paying for capacity should not affect their sales price of gas. There will be no distortion of competition.

   ii. The second reason is that is we must consider the capacity contract over its duration, not only at a single point in time. What we are seeing in the example above is that the shipper with long-term capacity is currently realising a profit on its capacity, relative to the market price. However, it is likely that for a capacity price that is constant in nominal terms, in the first years of the capacity contract the shipper would have been paying more than the regulated price, and making a loss on the capacity relative to the current market price.[59] However, again the shipper would have accepted the capacity as a sunk cost, and priced its gas in line with other shippers by reference to the current market price of capacity.

   iii. Hence, at any point in time the shipper may be paying more or less than the market price for capacity. However, a rational shipper would only agree to pay a fixed nominal price for capacity if the present value of the fixed capacity charges equalled the expected present market value of capacity. This evaluation would include some adjustment for the risk and benefits of holding a long-term fixed price capacity contract. But the fixed capacity charges are not a source of unfair competitive advantage. Rather the shipper has simply chosen to structure its capacity payments with a particular risk profile.

e. Another possible issue relating to the payable price is whether certain types of payable price structure could lead to excessive over or under-recovery.

   i. If the payable price was structured as a premium to the regulated tariff, there should never be under recovery of revenues.

[59] This discussion assumes that when setting a fixed nominal long-term price, the TSO would be allowed to set a reference price which exceeds the annual reference price, in anticipation that inflation will erode the real value of the auction price paid over time.

1. A discount to the regulated tariff may create an under recovery issue – however the TSO may gain more revenue by selling more capacity at a lower price, rather than selling less capacity at the regulated price. Hence even a discount to the regulated tariff could reduce the problem of revenue under recovery.

ii. Suppose that the payable price is set by auction in nominal fixed terms. The TSO should set the reserve price by forecasting the regulated tariff, and then ensuring that the fixed nominal tariff has the same present value as the expected regulated tariff over the duration of the capacity contract.

iii. However, forecasting the expected reference price is difficult and subject to error. Therefore the use of a fixed nominal tariff is more likely to lead to revenue over or under recovery in present value terms.[60]

iv. The use of a payable price that was fixed in real terms would mitigate inflation risk, but it could still lead to deviations from the current reference price for a given year and hence lead to over or under recovery of revenues.

1. One could argue that under and over recovery created by the difference in the fixed tariff and the current reference price would be mitigated if there were a series of annual long-term auctions. In any year, the TSO could be receiving capacity prices set in auctions of different 'vintages' – some prices could have been set 15 years ago, some 10 years ago and other 2 years ago. To an extent, forecasting errors may offset one another. But in our view they are unlikely to cancel out completely.[61]

f. In sum:

i. Differences in the payable price for long-term capacity at different IPs increase the complexity of the internal market, though the severity of this problem is not clear;

ii. Differences in the payable price for capacity at the same IP should not cause competitive distortions;

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60 The use of fixed tariffs will also mean that the TSO will likely recover more than its allowed revenues at the beginning of the contract term and less at the end. In present value terms there may not be any over or under recovery terms. But there could be under and over recovery year-to-year as a result of the use of fixed nominal tariffs. However, this could be dealt with by use of a dedicated fund for long-term capacity revenues. For example, if capacity revenues exceed allowed revenues in the early years, rather than refunding this 'over recovery' via the standard over/under recovery mechanisms, the 'excess' funds could instead be saved in anticipation that they will be required later when the receipts from long-term capacity payments fall below the regulated revenues. Such a fund would help stabilise tariffs for other users.

61 A further argument for the use of fixed tariffs is that they are preferred by shippers, and that hence the use of fixed tariffs could help encourage investment. However, since the payable price only applies to existing capacity, this argument is not relevant.

iii. A payable price that is not linked to the regulated tariff carries more risk of over and under recovery from year-to-year;

g. The above considerations imply that harmonisation could have benefits, and that a payable price linked to the regulated tariff would be less likely to lead to cost under or over recovery. Hence we give the payable price linked to the payable tariff a higher score (15/25) than the fixed (in real or nominal terms) payable price (10/25).

2. Feasibility and cost:

   a. It would be relatively simply to develop a harmonised payable price mechanism. The costs could be relatively small if current capacity contract price mechanisms were respected, and the harmonised mechanism was only introduced for new long-term capacity contracts. Costs would be much higher and disruption greater if the new harmonised tariff had to replace existing tariffs mid-contract. Compensation may have to be agreed and paid, and there could be complex legal issues with associated costs.

   b. A payable price that is not indexed could be more difficult to implement in a price-cap system, where the TSO is not protected against volume risk. In this case the NRA would have to also distinguish the revenue short-fall which rises for the TSO because the payable price deviated from the expected payable price, as opposed to the effect of volume sales being less than expected. This problem seems to be manageable but complicates regulation.

   c. It would be more challenging to calculate the reserve price for a payable price that is not indexed. The TSO would need to make forecasts of the expected regulated price for the IP for the duration of the capacity contract, and ensure that the expected nominal revenues met the allowed revenues in present value terms. This is clearly more challenging than the situation where the payable price is defined by reference to the regulated price.

   d. Because having the payable price fixed would be more difficult to implement while ensuring cost recovery, we give it a lower score (6/10) than where the payable price is linked to the regulated tariff (8/10).

3. Risk: The risk is that a harmonisation policy for the payable price could impose disproportional costs on TSOs for which the harmonised solution is not optimal, and/or that the choice of harmonised methodology could inadvertently undermine investment.

4. Proportionality: The imposition of a harmonised standard may not be proportional, if TSOs/NRAs find the trade-off between investment and cost-recovery an issue which should be decided at a MS level. For this reason we give a score of 5/10 for proportionality.

5. Subsidiarity: Despite the considerations above, because of the cross-border nature of the issue policy on the coordination of the pricing of IP capacity should be decided at the Community level, although this may not mean that a harmonised policy need result.

**Table 10: Evaluation of long-term payable price options**

| | Fixed real/nominal | Premium/discount on regulated rate | BAU |
|---|---|---|---|
| **Ability to solve the problems** | 10/25 | 15/25 | 2/25 |
| **Feasibility and cost** | 5/10 | 8/10 | 9/10 |
| **Risk** | 5/10 | 5/10 | 8/10 |
| **Proportionality** | 5/10 | 5/10 | 10/10 |
| **Total** | 25/55 | 33/55 | 29/55 |

## 6.7 Recovery of Allowed Costs

### Source and manner of cost recovery

1. Ability to solve problems associated with the policy area:

   a. Cost recovery mechanisms are associated with two main problems:

      i. First, high levels of under recovery via commodity charges could lead to a variable charge which significantly exceeds actual variable costs. This can lead to inefficiency and a loss of welfare. A capacity holder may opt not to flow gas if faced with a high commodity charge, even if the price difference between two markets exceeds the variable cost of transporting gas. This is inefficient.

      ii. Second, some cost recovery mechanisms could create capacity reference prices which are not sufficiently cost reflective. For example, if an attempt was made to always recover the costs of an IP from that IP, in the event of under-booking reference prices at the IP could spiral, leading to further under-booking. The resulting high capacity price would not be sufficiently cost reflective, which could block or distort cross-border flows.

   b. In section 6.3 we have discussed that short-term capacity charges higher than the marginal cost could also inhibit trade, though we noted the offsetting issue of cost recovery. However, even with short-term reference prices which are similar to pro-rated annual reference prices, it would still be possible for long-term capacity holders to arbitrage away price differences. But ‘high’ (meaning in excess of actual variable costs) commodity charges affect all capacity holders – both long and short-term. The commodity charge sets a limit to the convergence of market prices and prohibits all types of capacity holders from trading.

   c. The general principal that commodity charges should reflect as far as possible actual variable costs indicates that cost recovery mechanisms should focus on capacity charges. Recovering revenues via capacity charges will be less distortive to cross-border trade. Accordingly we give capacity charges a relative high score (20/25) and a lower score to cost recovery through commodity charges (10/25).

d. The second issue is whether cost recovery should be:

   i. 'narrow' – meaning that costs will only ever be recovered from an IP or a small group of IPs – or

   ii. 'broad', meaning that under recovery of costs at a particular IP could be recovered from a wide range of system users.

e. A broad cost recovery mechanism would seem to be better meet the objectives in terms of encouraging trade and cost reflectivity.

   i. The fundamental problem that cost recovery mechanisms must address is that some investments in the network are made without long-term contracts in place. That is, no user or group of users were underwriting the investment. When this is the case, the assumption is that NRA has sanctioned the investment of behalf of *all* network users. Therefore, when there is subsequent under recovery, it is cost reflective if all network users bear the cost.

   ii. It does not seem to make sense to focus cost recovery for an IP on the group of users who happen to be using the IP. If those users have not signed long-term capacity contracts, they are no more responsible for cost recovery at the IP than any other network user.

f. The above suggests that under-recovered revenues should be recovered from a broad group of users – that is all entry and exit points – via an uplift on capacity charges. Such a recovery mechanism would avoid distorting cross-border trade and/or creating reference prices at IPs that are not sufficiently cost reflective. Hence we give broad cost recovery a higher score (20/25) than narrow cost recovery (10/25).

g. Future cost under recovery issues could be reduced if investments in new capacity had the support of the market. The most tangible form of support would be in the form of long-term contracts. If market participants are prepared to buy long-term capacity for a significant portion of the new capacity, this sends a strong signal that the investment is likely to be 'used and useful', based on the information available at the time of the investment decision. Such market tests take advantage of the information that market players, who are active in the market on a regular basis, have on likely market developments. Investment decisions guided by the market are likely to have less chance of being stranded, because they draw on a much wider pool of information than if the NRA/TSO were making an investment decision in isolation.

   i. A relevant question is therefore whether market tests should be harmonised. The motivation would be to set a minimum standard of market test so as to avoid creating stranded costs.

   ii. A market test seems to make intuitive sense for the reasons outlined above. However, it is also possible to imagine several important exceptions where investment in capacity might be deemed desirable, even though there is no market support in the form of long-term contracts. The main exception would likely be that the investment is required for security of supply purposes. Therefore any market test requirement would need to have an exception for investments that are required for non-commercial purposes. Such a test would inevitably be somewhat subjective. TSOs and NRAs could easily avoid any harmonised market test by claiming an exception for security of supply or some other non-commercial reason. In other words, it would be easy for TSOs/NRAs who wanted to avoid a harmonised market test to do so. This would render the harmonised test rather redundant.

1. Moreover, while market tests have been applied successfully in the GB market, the tests have related mainly to the increase in capacity at entry points where gas production or LNG enters the GB gas system. In such cases, system users have a clear motivation to book long-term capacity to get their production to the market. On continental Europe, market tests would more often apply to connections between countries, rather than a connection of a production source to the market. Traders may be more reluctant to commit to capacity expansions between MSs that which will reduce price differences, and hence profits from arbitrage. We still support the application of market tests in continental Europe. But there may be more circumstances under which incremental capacity should be built even absent market support relative to the GB situation.

iii. Moreover, if costs are recovered according to the recommendations above, stranded costs should not disrupt cross-border flows. The main parties to suffer from poor investment decisions would be the users of the network – cross-border effects would be limited.

iv. Considering the above points, we do not recommend a binding harmonised market test, but rather the development of guidelines for good practice on market tests for new capacity. NRAs and TSOs would then adopt these on a voluntary basis.

2. Feasibility and cost: There do not seem to be any major conceptual issues with developing guidelines that specify that cost over or under recovery should be recovered in a uniform way from all entry and exit points. Moreover, we cannot identify any material differences between the different options in terms of cost and feasibility – hence we give all options the same score. For some existing regimes a change in the cost recovery mechanism would require a re-design of the tariff mechanism, which would entail a cost. However, implementing the harmonisation policy over a period of, for example, five-years would help mitigate the cost, since changes to the tariff regime would in any case be required during this time period.

3. Risk: It is difficult to identify any tangible risks of a harmonised policy for cost recovery. All policies score the same (8/10).

4. Proportionality: Given that differences in cost recovery policy could distort cross-border trade, and the costs of harmonisation do not seem to be particularly large, the policy seems to be proportional. Again we give all options the same score of 8/10.

5. Subsidiarity: Because of the cross-border nature of the problem action is required at the Community level.

**Table 11: Evaluation of cost recovery price options**

| | Capacity | Commodity | Broad | Narrow | BAU |
|---|---|---|---|---|---|
| **Ability to solve the problems** | 20/25 | 5/25 | 20/25 | 5/25 | 1/25 |
| **Feasibility and cost** | 7/10 | 7/10 | 7/10 | 7/10 | 9/10 |
| **Risk** | 8/10 | 8/10 | 8/10 | 8/10 | 9/10 |
| **Proportionality** | 8/10 | 8/10 | 8/10 | 8/10 | 10/10 |
| **Total** | 43/55 | 28/55 | 43/55 | 28/55 | 29/55 |

**Timing of cost recovery**

1) Ability to solve problems associated with the policy area:

   a) It is not clear that differences in the timing of cost recovery contribute to any of the problems identified. The key potential issue is that the need to recover revenues from a previous time period could make references prices in the current period less cost-reflective than would be ideal.

   b) It is true that waiting for until the next regulatory period to recover costs could lead to a build-up of liabilities which might not be desirable. But on the other hand over a longer period of time some over and under recoveries could cancel out from one year to the next.

   c) The amount to be recovered may become larger by waiting until the next regulatory period, compared to re-covering revenues in the next tariff year. But assuming that the under recovered revenues will be recovered over the entirety of the next regulatory period the time to recover the revenues is also longer.

   d) Accordingly it is not clear that a policy of recovering revenues in the next regulatory period would necessarily change the reference price in any particular year by more or less.

   e) For the reasons above we give the harmonised timing of cost recovery policy a relatively low score of 10/25 for problem solving.

2) Feasibility and cost: There are no major conceptual difficulties in developing a harmonised approach to the timing of cost recovery. The costs involved would be for the changes to the procedures for any existing cost recovery mechanisms that were not compliant.

3) Risk: The main risk is that costs are incurred pursuing a policy options which does not contribute to achieving the policy objectives for the gas market.

4) Proportionality: The imposition of a harmonised standard could be disproportional.

5) Subsidiarity: Action would be better taken by Member States. There does not seem to be a compelling case for action at the Community level.

**Table 12: Evaluation of cost recovery timing options**

| | Harmonised timing | BAU |
|---|---|---|
| **Ability to solve the problems** | 10/25 | 2/25 |
| **Feasibility and cost** | 7/10 | 9/10 |
| **Risk** | 4/10 | 10/10 |
| **Proportionality** | 4/10 | 10/10 |
| **Total** | 25/55 | 31/55 |

### 6.8 Harmonisation of setting of Entry-Exit tariffs for Gas Storage

1. Ability to solve problems associated with the policy area: A policy to harmonise the treatment of gas storage tariffs for gas storage could avoid distorting incentives to invest in storage. The underlying economics of the relative locations would play a stronger role in storage investment decisions.

    a. However, the main challenge with developing a policy for storage entry and exit tariffs is ensuring that it is addresses the problems identified while remaining non-discriminatory.

    b. The problem described was that storages can perhaps reduce investment costs in gas transmission by allowing the construction of smaller import pipelines than would be the case without storage.

    c. Therefore the problem, as described, seems to suggest a tariff which for example estimates the future costs of the network without the storage project, the costs with the storage, and then passes on some of the savings realised to the storage in the form of lower entry and exit tariffs.

    d. The problem with this solution is that there may be other types of users who could also claim that because of their pattern of gas use that they reduce investment costs, or at least are responsible for less costs than the average user. Determining entry and exit tariffs for storage based on their contribution to system costs, but employing a different methodology for other users could be discriminatory.

    e. Moreover, more cost reflective entry and exit tariffs should already help gas storages.

        i. For example, suppose as in the problem description, the gas storage is built relatively close to the main centre of gas demand, and far from main point of gas import. It would book capacity from the border to the storage in the summer when the storage facility is filled, and then capacity for the relatively short distance from the storage to the market in winter as it sends out the gas. If tariffs are broadly cost reflective, then summer capacity should cost less than winter capacity, and it should cost less to transport gas a short distance than a longer distance.

f. Therefore it is not clear that gas storages need a special entry exit tariff regime. Rather, they would enjoy the benefits of a cost reflective tariff along with other users. While the approach to storage tariffs could be partially harmonised, this should be in line with the general recommendation for harmonisation of the reference price and cost allocation. A tailored tariff regime for gas storage risks being discriminatory. Accordingly, we give the policy a relatively low score of 8/25.

2. Feasibility and cost:

   a. Apart from the discrimination issues discussed above, developing a specific tariff regime for gas storage based on avoided investment costs could present some practical challenges. Specifically, agreeing on methodology to quantify the investment costs with and without the storage facility would involve some subjective judgement. There do not appear to be any unusual costs associated with the policy other than the normal issues of changing and implementing the new tariff regime. Hence we give a score of 6/10.

3. Risk: The risk is that attempting to make tariffs for storage more cost reflective via a special tariff regime would create discrimination against other network users – score 4/10.

4. Proportionality: The option seems broadly proportional in that it interferes in a relatively narrow area of transmission tariff policy which has cross-border implications – hence we give a score of 7/10.

5. Subsidiarity: Action at the community level is required to avoid distorting cross-border investment incentives.

   a. We conclude that while some partial harmonisation of entry-exit tariff methodologies for gas storage is required, this should be part of a more general tariff harmonisation policy discussed in section 6.2. We do not recommend a specific or tailor made entry-exit tariff regime for gas storages.

**Table 13: Evaluation of a harmonised tariff policy for gas storages**

| | **Harmonised timing** | **BAU** |
|---|---|---|
| **Ability to solve the problems** | 8/25 | 2/25 |
| **Feasibility and cost** | 6/10 | 9/10 |
| **Risk** | 4/10 | 9/10 |
| **Proportionality** | 7/10 | 10/10 |
| **Total** | 25/55 | 30/55 |

### 6.9 INCREASING TRANSPARENCY REQUIREMENTS

1 Ability to solve problems associated with the policy area:

1.1 Publishing sufficient data and models to allow network users to understand how references prices are set, and model the effect of different assumptions on the reference prices, would solve the transparency problem identified in section 4.7. There do not seem to be any other issues or trade-offs that might counsel against increased transparency, and increased transparency is clearly an objective of the internal EU gas market. Hence we give the policy a high score of 22/25.

2 Feasibility and cost: All of the information must be available to the TSO. Therefore it is simply a matter of ensuring that the reference price methodology and documentation is in a format that is easily understood my system users, and ideally that the tariff model does not require any special software to run. The costs of preparing and publishing the information should be low. Score: 8/10.

3 Risk: It is difficult to see any risks associated with this policy option. Score 8/10.

4 Proportionality: The option is proportional, in that it furthers the goal of transparency in the gas market and enables system users to make better decisions at little extra cost. Score 8/10.

5 Subsidiarity: Since system users need transparency across multiple MSs. Therefore co-ordinated action on transparency is required, and action should be taken at the Community level.

**Table 14: Evaluation of an increased transparency requirements for tariff methodologies**

| | **Increased transparency** | **BAU** |
|---|---|---|
| **Ability to solve the problems** | 22/25 | 1/25 |
| **Feasibility and cost** | 8/10 | 10/10 |
| **Risk** | 8/10 | 8/10 |
| **Proportionality** | 8/10 | 10/10 |
| **Total** | 46/55 | 29/55 |

## 6.10 Costs and Benefits of the Policy Options

The two main areas of cost benefit as a result of tariff policy harmonisation are:

- Improved cross-border trade – removal of distortions to cross-border trades should make trade more efficient and in some cases increase the volume of trade;
- More efficient investments in gas infrastructure – if cross-border tariffs are more cost reflective, then shippers should make decisions regarding where they flow gas which better reflect the underlying costs of using the system. This will lead to more efficient investments.

In this section we set out to estimate the costs and benefits of implementing the package of policy options. However, we must recognise that developing detailed estimates of the benefits of the different policy options would be not only difficult and expensive, but perhaps even impossible. For example, to estimate the relative benefits of partial and full harmonisation in full, one would need to perform the following steps:

1. Obtain the tariff models of all of the gas TSOs in the EU;
2. Calculate the tariffs with the proposed fully harmonised methodology and the partial tariff harmonisation;
3. Estimate the effect of the new tariffs on both gas flows and likely future investments by the TSOs.

The first two steps are theoretically possible if TSOs made the tariff models available, but would be very time consuming and expensive to complete. The last step, of estimating the effect of changed tariffs on shipper behaviour, flows and investment decisions, would be largely a matter of guess work. Even if the analysis was underpinned by detailed surveys of shippers and interviews with TSOs, there is not guarantee that the answers would be accurate.

Many cost-benefit analyses face similar difficulties. However, the point of the analysis is not necessarily to make an accurate estimate of the costs and benefits, although where possible this is of course the first-best solution. Rather, the ultimate aim is to be reasonably sure that the likely benefits of the proposed policy changes outweigh the estimated costs. This is a somewhat lower hurdle, and it is the approach that we take here in light of the intractable difficulties of coming up with a very detailed estimate of costs and benefits.

**Possible magnitude of the benefits**

In its Ten-Year Network Development Plan (TYNDP), ENTSOG estimates that there are around €58.6 billion of gas transmission infrastructure projects that are planned between 2011 and 2020 but have not reached Final Investment Decision (FID).[62] There is a further €2.6 billion of gas storage projects which have not reached FID, giving a total of €61.2 billion.[63] The non-FID projects are relevant because these are the ones that could potentially be influenced by changes in the transmission tariff structure. Supposing that changes in tariff policy only start to influence investment decisions from the beginning of 2013, and that the possible investments are spread evenly over the 10 year period, this still gives an amount of about €50 billion that could be influenced by the harmonisation of tariff policies. We should then further account for the fact that under any policy action only some of these projects would reach FID – so we further reduce the number by 50% to get a value of €25 billion that will be made in transmission and storage infrastructure that could be influenced by the harmonisation of tariff policies.[64] If we further suppose that the adoption of

62 ENTSOG, Ten-Year Network Development Plan 2011 – 2020, 17 February 2011, p.23.

63 The TYNDP also includes €6.6 billion of LNG projects which have not reached FID. We leave these out as it is less obvious that decisions regarding terminal investments could be influenced by the policy options we recommend adopting.

64 Our estimate is somewhat conservative, in that we only account for investments required in the TYNDP planning window which ends in 2021. Of course investments in gas infrastructure will also be required after 2020, and these investments could also be influenced in a positive way by harmonised transmission tariffs. However, we have no estimate available for the magnitude of these investments so we leave them out of the cost-benefit analysis. On the other hand, we have not taken the present value of the costs, which would decrease

harmonised tariffs saves 1% of the above amount because of more efficient flows through the EU, this gives us a benefit of about €250 million.

**Table 15: Trade of LNG and Pipeline Gas within the EU-27 (Bcm)**

| | Belgium | Denmark | France | Germany | Netherlands | Spain | United Kingdom |
|---|---|---|---|---|---|---|---|
| Austria | - | - | - | 0.44 | - | - | - |
| Belgium | - | - | - | 0.81 | 5.55 | - | 4.95 |
| Denmark | - | - | - | 0.15 | - | - | - |
| France | 1.20 | - | - | 3.98 | 6.85 | 0.63 | 0.60 |
| Germany | - | 1.14 | - | - | 24.20 | - | 2.85 |
| Hungary | - | - | 0.70 | 0.30 | - | - | - |
| Ireland | - | - | - | - | - | - | 5.29 |
| Italy | - | - | - | 2.50 | 8.11 | - | 0.50 |
| Luxembourg | 0.62 | - | - | 0.75 | - | - | - |
| Netherlands | - | 0.76 | - | 2.61 | - | - | 1.46 |
| Poland | - | - | - | 1.07 | - | - | - |
| Portugal | - | - | - | - | - | 0.52 | - |
| Spain | 0.08 | - | 0.23 | - | - | - | - |
| Sweden | - | 1.64 | - | - | - | - | - |
| United Kingdom | 1.26 | - | - | - | 8.07 | - | - |
| Total | 3.16 | 3.54 | 0.93 | 12.61 | 52.78 | 1.15 | 15.65 |
| **Grand Total** | **89.82** | | | | | | |

Source: BP Statistical Review 2011

The other potential source of benefits is improved cross-border trading. Based on data from BP, in 2010 about 90 billion cubic metres (bcm) of gas was traded between MSs in the EU – Table 15 illustrates. The approximate market value of this gas in 2013 is likely to be about €27 billion.[65] Of course the value added from trading, and hence increased trading, is much less than the underlying commodity value. One approximation of the value added from trading could be the bid-offer spread, which is the difference between the buying price and the selling price of a 'market maker'. It is a measure of transaction costs in the market. If the gain from trade was not at least as large as the bid-offer spread, presumably no trade would take place. Accordingly the bid-offer spread is a reasonable lower limit for estimating the gain from trade. According to Heren, a trade publication, bid-offer spreads of around €0.3/MWh, or €0.00345/m$^3$ are typical is relatively liquid gas markets, so using this number will tend to under estimate the gains from trade in less liquid markets. Multiplying a typical bid-offer spread by the volumes of gas traded across EU borders gives an estimate of the value of trading of about €300 million.

the estimate. However, given that cots should be discounted at a risk-free rate, which is low and expected to remain low, discounting would not substantially reduce the estimated savings.

65 Based on a spot gas price of about €26/MWh. Actual prices in oil-indexed contracts will likely be higher, so this probably underestimates the average price paid for gas in the EU.

Again, supposing that tariff harmonisation and improvements in tariff methodologies led to a 1% increase in the gains from trade, this would lead to a benefits of about €3 million as a result of improvements in trade. However, this amount seems relatively negligible compared to the possible savings from more efficient infrastructure investment, and so we can approximate the potential benefits as being about €250 million.

Some markets in the EU may also experience more competition as a result of the policies, for example where a lack of backhaul capacity is preventing market entry or where excessive entry tariffs at the border are either inhibiting entry or raising the market price of gas. However, such circumstances may only apply to a handful of the EU's gas markets, and so we leave this benefit as an un-quantified upside. However, we note that the results of increased competition could be considerable. For example, if 10% of EU gas experienced a price decline of 1%, this would deliver savings to consumers of about €26 million.

**Possible magnitude of the costs**

It seems that most of the costs of tariff harmonisation would fall on the TSOs, as they have to prepare, document and implement the harmonised tariff structures in detail. We have not received any submissions from TSOs with estimates of the likely costs. However, costs in the order of €500,000 per TSO would seem reasonable to perform the tasks required. Given that there are around 40 TSOs in the EU, this amounts to a cost of €20 million. These costs are high, in that we estimate the costs per TSO without assuming any synergies between them. In reality, ENTSOG and perhaps other organisations could co-ordinate the development of the detailed tariff policies to make the implementation more efficient.

We do not foresee any particular costs on the part of shippers, as long as the changes are implemented in a way which respects the normal regulatory cycle and does not cause any changes beyond what might reasonably be expected in the normal course of business.

**Possible net benefit**

Based on the analysis above, we estimate a total net benefit of the policies of around €230 million. In essence, the amounts that are planned to be invested in gas infrastructure are very large, so that even a small efficiency benefit is sufficient to justify the cost of modifying the methods for setting tariffs. As long as the changes are implemented in a way which avoids large costs for shippers, including legal costs, we can be confident of a significant net benefit.