Study on Entry-Exit Regimes in Gas

Part B: Entry-Exit Market Area Integration

Entry-Exit Regimes in Gas, a project for the European Commission – DG ENER under the Framework Service Contract for Technical Assistance TREN/R1/350-2008 Lot 3. Contract ENER/B2/267-2012/ETU/SI2.628337

In collaboration with COWI Belgium

Groningen – The Netherlands, July 19 - 2013

74102208

Study on Entry-Exit Regimes in Gas

Part B: Entry-Exit Market Area Integration

Groningen – The Netherlands, July 19 - 2013

DNV KEMA

By order of the European Commission – DG ENERGY

author : MV, BK

reviewed : CH

47 pages

approved : CH

KEMA Nederland B.V. Energieweg 17 9743 AN Groningen P.O. Box 2029 9704 CA Groningen The Netherlands
T +31 50 700 9700 F +31 50 700 9858 www.kema.com Registered Arnhem 09080262

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 APPROACH TO COST-BENEFIT ANALYSIS

This chapter deals with the cost-benefit analysis regarding the merger of different market areas. First, the approach towards estimating the cost involved in merging different market areas is discussed. Afterwards, the approach and results of the benefit analysis are presented.

The cost-benefit analysis is conducted for three different combinations of market areas. These market areas were chosen in close cooperation and after consultation with the members of the Steering Committee governing this project. The following combinations were chosen:

1. Spain and Portugal
2. Republic of Ireland, Northern Ireland and Great Britain
3. Hungary and Romania

The next section presents the approach to the cost analysis.

1.1 Approach to Cost Analysis

The cost analysis we have adopted consists of two separated steps. In the first step we determine the interconnection capacity additionally required between the two market areas which are being considered for a market area merger. In the second step we elaborate on the different ways to enable the market area merger given the potential capacity requirements from the first step. The most obvious way for enabling the market area merger would be to invest in additional physical transport capacity. However, given certain circumstances, other non-investive or market-based ways might be more appropriate. In case no additional infrastructure is needed, as the existing interconnection infrastructure is sufficient, the second step is omitted.

1.1.1 Step 1: Determination of Required Interconnection Capacity

We have built a model in order to determine the required interconnection capacity between the market areas necessary to enable a market merger. The primary underlying assumption used in this model is the existence of a decoupled entry-exit system. The model itself regards the entry-exit systems of the market areas as a black-box. This means that the (firm) capacities offered by the respective TSOs can be guaranteed after a merger. As such, we do not consider any potential bottlenecks in the existing transmission grids in the market areas and do not perform any static and/or dynamic network flow calculations. It is thus assumed that all possible flow combinations, as currently offered by the TSO, can be accommodated – this aligns with the main characteristic of an entry-exit system without any locational restrictions. Using this starting point, we are able to derive the interconnection capacity required under various flow scenarios.

For each combination of market areas, we have constructed flow scenarios on the basis of observed flows and capacities in the year 2012. The parameters used for determining the required interconnection capacity are the entry and exit points of the two relevant market areas. For each of the entry and exit points, we have estimated the typical usage in terms of their technical capacities (i.e. x% of technical capacity) and the correlation between different entry and exit flows.

In general, the following entry points are included:

- Entry points used for supplying domestically produced gas to the transmission network.
- Send-out from LNG terminals.
- Entry points for importing gas via pipeline interconnections from other market areas/countries.

- Withdrawal points from domestic storages for supply into the transmission network.

In a similar fashion, the following typical exit points are taken into account:

- Exit points for supplying the local market used to fulfill domestic demand.
- Exit pints for exporting gas to other countries.
- Exit points for injecting gas into storages.

In line with the principles of an entry-exit system, it should be possible for a network user to contract capacity at one market area's entry point and the other market area's exit point in case the two market areas are merged into a single entry-exit system. In such a situation, the former market area may be regarded as the supplying region and the latter market area, where the network user has booked its exit capacity, as the receiving region. However, at a different point in time and depending on the contracted capacities, these roles can alternate and the supplying side may become the receiving side. For both of these situations, it is required to have sufficient interconnection capacity in place between the two market areas. This situation is displayed in Figure 1 below[1].

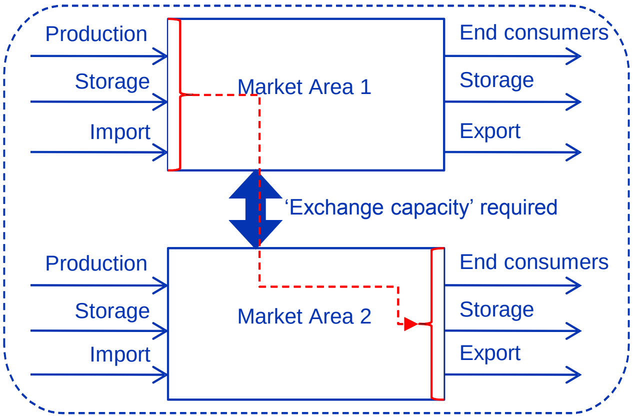


Figure 1: Schematic Diagram Presenting the Interconnection to Merge the Market Areas

Using this representation and acknowledging the possible flow situations, it is possible to derive the interconnection capacity which would be required between the two market areas in order to merge them without jeopardising the integrity of gas supply. The first step to derive this additional interconnection capacity is to add up all the entry point flows of the supplying side and subtracting all the exit point flows of the supplying side; this results in the capacity available for supply via the interconnection. Secondly, the entry point flows of the receiving side are added and subtracted with the exit point flows of the receiving side. This results in the capacity that could be used up by the receiving side if it receives gas via the interconnection.

Finally, the actually interconnection capacity required in the direction from the supplying to the receiving market areas equals the lesser of:

- the capacity available for supply via the interconnection and
- the capacity which could be used up by the receiving side.

[1] The approach is largely based on the approach adopted in the study by the German TSOs and PwC, "ERGEBNISBERICHT - Kosten-Nutzen-Analyse einer Marktgebietszusammenlegung von GASPOOL und NetConnect Germany nach § 21 GasNZV", October 2012.

Existing interconnection infrastructure between the two countries is subtracted from this figure to find the capacity which needs to be built in addition. With reference Figure 1 and thus assuming that Market Area 1 is the supply region, this can be described as follows:

A	Sum of entry flows Market Area 1
B	Sum of exit flows Market Area 1
C	Surplus available from Market Area 1 [A – B]
D	Sum of exit flows Market Area 2
E	Sum of entry flows Market Area 2
F	Maximum intake from Market Area 1 [D – E]
G	Required interconnection capacity [min(C;F)]
H	Existing interconnection capacity
I	Additionally required interconnection capacity [G-H]

It should be acknowledged that it is important to correctly choose the flow scenarios that will be used. Generally, the larger the entry capacities and the smaller the exit capacities in the supplying area are, the larger the potential interconnection capacity. Similarly, the larger the exit capacities and the smaller the entry capacities in the receiving area are, the larger the potential interconnection capacity. Conversely, the larger the existing interconnection infrastructure currently in place, the smaller the potential interconnection capacity.

Using only firm capacities may result into large interconnection requirements and can be regarded as a worst case scenario[2]. Therefore, it is preferred to use scenarios that will result in typical, but robust enough, flow situations in order not to overestimate the required interconnection capacities. Indeed, overestimating the required interconnection capacities may result into inefficient investments. The choice of the scenarios and the capacities taken into account are thus an important choice in the derivation of the interconnection capacities. In our analysis, we have derived these scenarios based on the implemented flows in 2012. For each combination of market areas, we have developed a conservative and a more optimistic scenario.

This calculation is performed twice, first taking market area 1 as supply side and market area 2 as receiving side, thus finding the interconnection infrastructure needed for supply from market area 1 to market area 2. Then we take market area 2 as supply side and market area 1 as receiving side, thus finding the interconnection infrastructure needed for supply from market area 2 to market area 1.

1.1.2 Step 2: Estimation of Associated Investment

Once the additionally required interconnection capacities are known, we can calculate the associated investments. However, as an alternative to this, other methods to facilitate market area merger can be considered. These methods will be described shortly as well if appropriate. First, we discuss our way to estimating the associated investments.

Step 1 may result in an estimate of the additional interconnection capacity required. In order to assess the investment associated with enabling this capacity, we multiply this figure with a typical unit price for new transmission capacity. We estimate that the typical investments required for implementing 1 GWh/day are somewhere between €1200 and €1900, depending on the pipeline diameter[3]. We take an

[2] For example, an assumption under the worst case scenarios would be to have the domestic demand in the supplying region be equal to zero whereas the demand in the receiving region would be set at maximum demand possible. This assumption may be unrealistic and result in large investments needed.

[3] Due to economies of scale, the relative investments generally drop when larger diameter pipelines are constructed.

average value of 1500 €/GWh/day[4]. Also, this figure generally applies to North-Western Europe which is on average more densely populated compared to e.g. Romania. Also, specific information regarding capex and opex, in unitary costs, of various types of gas infrastructures in Spain as adopted by the Spanish government was provided. These costs were used in cases where deemed appropriate.

In order to convert the associate investment figure into an estimate for annual cost, we annuitise the investment figure using an annuitisation factor of 0.085[5].

1.2 Approach to Benefit Analysis

In this section we discuss our approach to assessing the benefits of merging two market areas. The benefits may be due to two different effects:

1. Integration benefits
2. Benefits from enhancement of competition

In the following section we discuss the underlying rationale and our approach to assessing both effects.

1.2.1 Integration Benefits

The second effect that may result in benefits due to the integration of the market areas and therewith creation of a single demand and supply curve. The main benefits will be that cheap gas, before the merger only available in one market area, becomes available for consumers in the other market area as well. Consequently, this will reduce the total expenditures spent for the gas supply. The benefits are again seen from the consumers' perspective.

These integration benefits can be assessed in different ways. One frequently observed way is to assess the spot price differences between two countries and, in case interconnection capacity is not fully utilised, estimate resulting flows from the cheaper area to the more expensive area. However, this approach is only possible when sufficient data on daily gas prices and flows are available. As these data might not be available for the candidates under consideration a different approach needs to be used. To this extent, we have built a simplified model that simulates the gas markets on a daily basis subject to the constraints applicable. The basic structure of this model is shown in the figure on the next page.

[4] COWI/DNV KEMA, "Study on Synergies between Electricity and Gas Balancing Markets (EGEBS)", October 2012.

[5] The annuitisation factor has been calculated assuming a 35 year asset life and an allowed rate of return of 8.0% on capital expenditure.

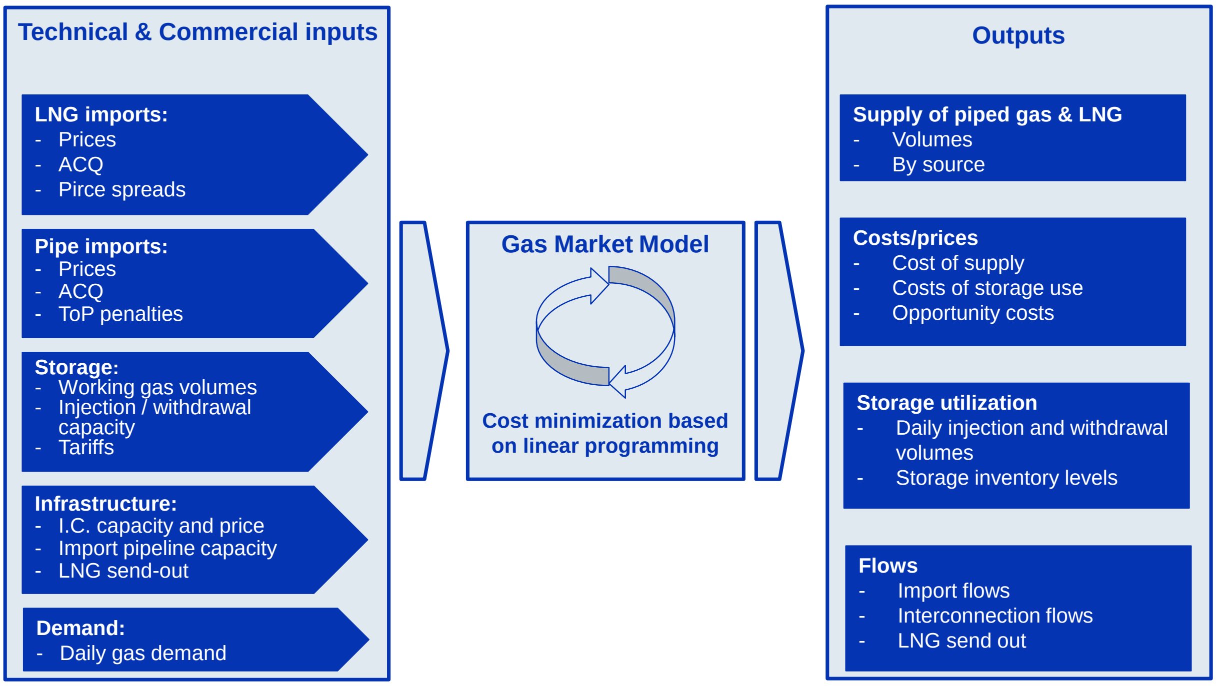


Figure 2: Principal Structure of the Simplified Gas Market Model

The model solely includes the two market areas under consideration, which implies that it provides for a simplified representation of real life only. However, as illustrated by Figure 2, it does cover all relevant entries and exits of the gas networks, including the interconnections with neighboring countries. By optimising the use of different sources, including the use of underground storage, this model replicates the operation of the wholesale gas market under the assumption of perfect competition and zero demand elasticity.

In addition to this, the basic structure of the model (e.g. the technical capability of the infrastructure or price scenarios) has been supplemented by several additional constraints and assumptions, such as

- Seasonal constraints on underground storage inventory levels;
- Take-or-pay obligations for pipe and LNG imports;
- Minimum send-out requirements for LNG terminals;
- Arbitrage opportunities for the supply of LNG;

In order to allow for a fair comparison, two different simulations are executed by the model. In one simulation, the so-called Status Quo situation, existing constraints are applied to the model such as the available interconnection capacity, costs associated with the usage of interconnection, and contracts with between consuming and producing countries. In the second simulation, the constraints not applicable in an integrated market were omitted in the model. The benefits of market integration equal the difference between the total costs faced by consumers (i.e. purchase, storage, and opportunity) in both simulations.

1.2.2 Benefits from Enhancement of Competition

Competition may increase as a result of merging two market areas. Increasing competition may decrease gas prices which can be regarded as a benefit from the consumer's perspective. The benefits will be highest if one or both of the market areas currently have an oligopolistic structure instead of a competitive market. In short, by merging both markets, competition may be increased which may ultimately, under certain assumptions and using the Cournot equilibrium, result in a lower gas price.

The Cournot model can be used to estimate potential price drops due to an enhancement in competition. The use of this model requires that either the marginal costs of gas supply are known or the long term price elasticity of demand.

The Cournot model can be expressed by the following relationship[6]:

$$[p(Q) - c'_i(q_i)] / p(Q) = s_i / \varepsilon.$$

In which,

$P(Q)$ = gas price at quantity Q

s_i = the market share of firm i

ε = is the (long-term) price elasticity of demand

$c'_i(q_i)$ = the marginal costs of production for firm i

Therefore, given either the marginal costs of production $c'_i(q_i)$ or the long-term price elasticity of demand ε, we can assess the impact of more competition on the gas price $p(Q)$.

However, marginal costs of gas supply are mostly confidential for companies operating in the market area and not publicly available. Similarly, estimates for the price elasticity of demand are scarce as well as only several studies known to us have estimated these elasticities[7,8,9]. Therefore, assumptions and estimates will be made where necessary and the results of this analysis should thus not be interpreted as a fully-fledged competition analysis.

---

[6] See e.g. Robert D. Wilig (Department of Justice), "Merger Analysis, Industrial Organization Theory, and Merger Guidelines", Brookings Papers: Microeconomics 1991 or R. Preston McAfee and Tracy R. Lewis, "Introduction into Economic Analysis", 1999.

[7] Joutz, F. and R. Trost (GeorgeWashington University) and Shin D. and B. McDowell (American Gas Association), "Estimating Regional Short-run and Long-run Price Elasticities of Residential Natural Gas Demand in the U.S.", USAEE Working Paper, August 1999.

[8] Bernstein, R. and R. Madlener (E.ON Energy Research Center), "Residential Natural Gas Demand Elasticities in OECD Countries: An ARDL Bounds Testing Approach", FCN Working Paper No. 15/2011, October 2011.

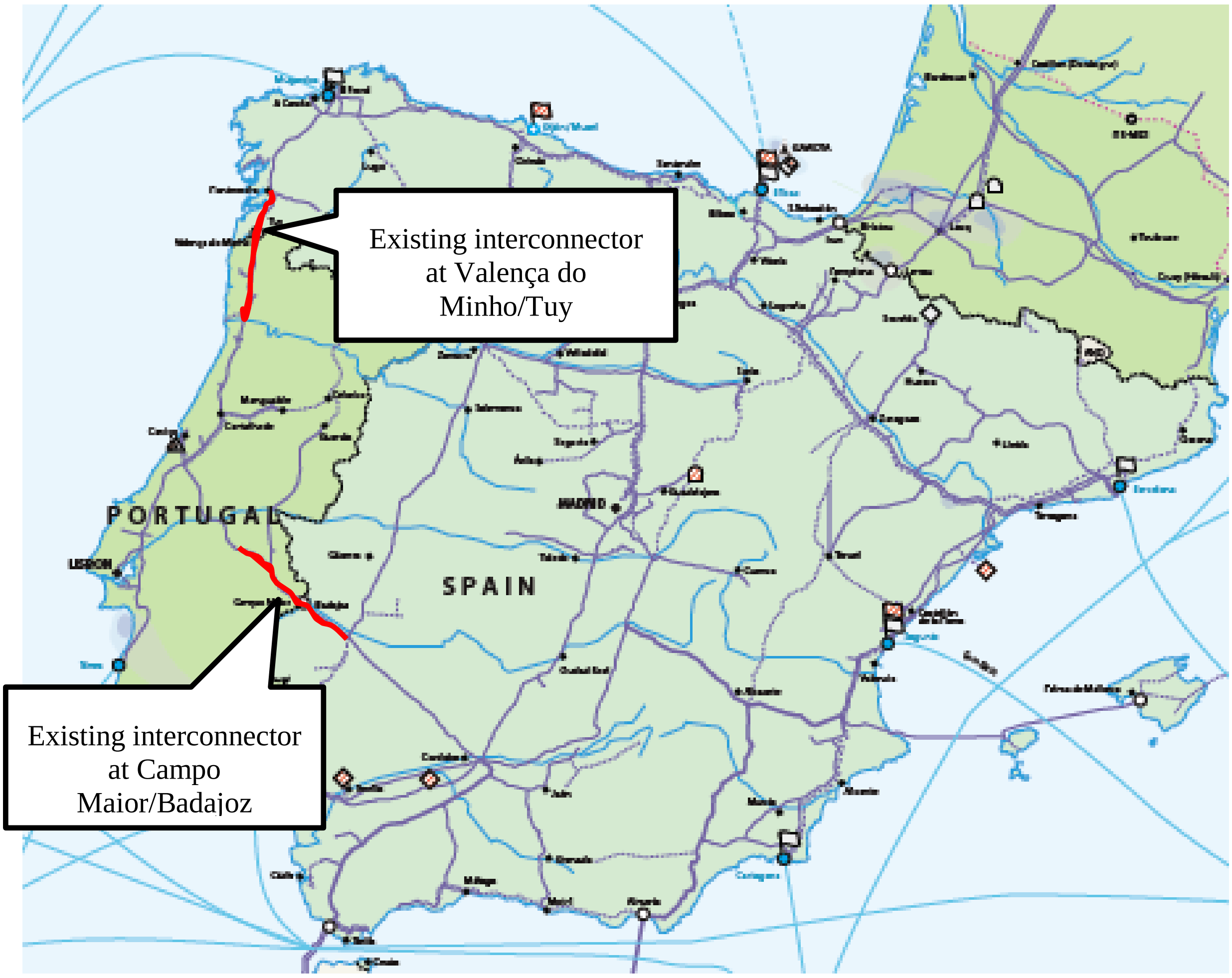
[9] Liu, G. (Statistics Norway), "Estimating Energy Demand Elasticities for OECD Countries A Dynamic Panel Data Approach", Discussion Papers No. 373, March 2004.

2 SPAIN – PORTUGAL

In this section we first discuss the results of the cost assessment. The different scenarios and their underlying assumptions that were considered are documented in the slides annexed to this report. In this section we focus on the results of the calculation. As the results are dependent on the assumptions taken, we have also analysed the sensitivity of the final results on our assumptions. After the cost assessment, we discuss the results in terms of potential benefits of a market area merger.

2.1 Costs of Merging Spain and Portugal

Currently, Spain and Portugal are interconnected at two different interconnections points; one at Campo Maior/Badajoz and another one at Valença do Minho/Tuy (Figure 3). These two interconnection points are commercially grouped into a single virtual interconnection connection point. In line with the approach to the cost assessment as explained in the previous section, we treat this point as a single interconnection point as well.



Source: ENTSOG

Figure 3: Map of Spanish and Portuguese Transmission Systems

For each of the entry and exit points we have analysed the daily flows during the year 2012 and expressed these flows as a percentage of the available technical capacity. Subsequently, we have defined two scenarios which represent a typical summer, winter or spring/fall day. The scenarios were chosen such that they would result in a high utilisation of the interconnector. Furthermore, in order to account for the possible uncertainty, no specific days, but a combination of days which occurred during a similar periods of the year, were taken into account.

For each of the two possible directions, i.e. Spain supplies Portugal and Portugal supplies Spain, two different scenarios were developed. One of these scenarios (“Conservative”) resulted in a higher load compared to the other scenario (“Optimistic”). The flows used in each of these scenarios, expressed as a percentage of the technical capacity, are provided in the slides annexed to this document.

Based on these two scenarios the required interconnection capacity was derived. Only in the Conservative scenario, additional interconnection capacity in the direction Portugal to Spain may be required[10]. The amount of capacity equals 88 GWh/d (or about 308,000 m^3/h). This capacity can be implemented in two different ways: either an additional pipeline is constructed or additional compression is put in place. As there is already a pipeline in place, the latter of the two measures is generally less expensive especially taking into account its expected low utilisation. One compressor station with a power of 8.8 MW would be required in Portugal and would cost 23 M€ in a 2+1 configuration[11]. This equals yearly costs of around 2 M€.

The results show that, under certain arguably rare circumstances, only in the direction “Portugal to Spain” additional interconnection capacity is required. Therefore, given the exceptionality of this situation, it is questionable whether the investment will be efficient. Furthermore, the resulting additionally required interconnection capacity is quite sensitive to the choice of the input parameters (Figure 4). For example, when assuming that the LNG terminal Sines and the UGS Carriço do not send out at the same time, no interconnection capacity is required. Similarly, if we assume that the minimum demand is 20% higher or the LNG send out is 20% lower compared to the Conservative scenario, the additionally required interconnection capacity is almost halved.

[10] In the conservative scenario domestic demand in Portugal was low. Therefore, gas send from the Portuguese storage and LNG terminal could be more than what Portugal itself can consume. Alternatively, the corresponding volumes of LNG deliveries could of course also be shipped to Spain directly. This highlights the potential value of other instruments that can be used as an alternative to transmission expansion.

[11] A compressor station on the pipeline from Pombal to Campo Maior/Badajoz would be required in order to compensate pressure drops due to higher flows.

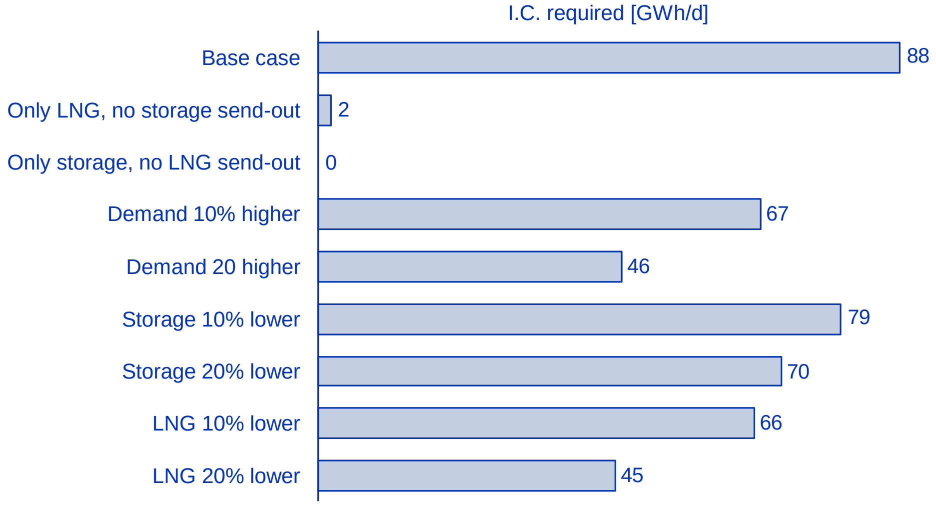


Figure 4: Sensitivity Analysis on Input Assumptions

Based on the above, using alternatives to investing in additional interconnection capacity could be more obvious. Such non-investive measures can either be administrated measures or market-based instruments. Administrated measures can be used to restrict network users' flexibility or to mandate changes to the planned use of the network. Market-based instruments are designed to incentive network user to adjust or avoid entry/exit flows which may lead to operational problems. Administrated measures come largely free of charge to the TSO, with the exception of for example a reduction in tariffs for interruptible or restricted capacities. Market-based instruments are generally accompanied by a remuneration for the actions taken. A detailed description of various non-investive measures is provided in Section 5.

Furthermore, the auction held last year for yearly capacity on the virtual interconnection point between both countries and in both directions, got no interest from market parties and no capacity was subsequently allocated. Although this may not guarantee that flows from Portugal will never top the current firm capacity, it does show that at the moment market parties do not expect to ship large volumes from Portugal to Spain under the present conditions (e.g. interconnection tariffs).

2.2 Benefits of Merging Spain and Portugal

In order to assess the benefits of integrating the Spanish and Portuguese gas markets, we have applied both of the approaches as discussed in Section 1.2. Thus, we have calculated both the benefits from the enhancement of competition as well as the integration benefits. The total quantifiable benefits from an integration of the Spanish and Portuguese gas markets equal the sum of the two.

2.2.1 Integration Benefits

Besides the benefits from an enhancement in competition, also potential benefits that may arise from merging both markets were examined. Benefits may arise due to various reasons:

- Abandonment of potential destination clauses may result in a cheaper supply to the other market area in some cases.
- Elimination of restrictions on interconnection capacity that may result in the supply of gas to the other market at lower prices.

In order to assess the benefits of integrating the Spanish and Portuguese markets, the model as explained in Section 1.2.1 was applied to these markets. The model's parameters were tuned such that it represented the Spanish and Portuguese situation as much as practically possible.

As explained above, using this model, two different situations both using data for the year 2012 can be simulated. As such, in the first simulation, the model contained constraints that mimicked the current situation with two separate market areas. In the second simulation, the constraints were removed in order to represent an integrated simulation. The benefits from integration equal the difference between the total costs in both simulations. Total costs are defined as the sum of total purchasing costs of gas by pipeline and LNG, storage costs and opportunity costs incurred for not diverting LNG to Asian markets.

The benefits for 2012 were calculated to be €5 million. Given the total size of the Spanish and Portuguese gas markets, these benefits seem to be limited. This might be explained as follows. Currently, the Portuguese and Spanish gas markets are already relatively well interconnected and free capacity is available between the two countries. Furthermore, both Spain and Portugal share the same supply sources as they are both supplied by Algerian pipeline gas and LNG.

2.2.2 Benefits from Enhancement of Competition

We have applied the Cournot model to the Portuguese gas market only as the Spanish gas market is relatively competitive with a HHI of just above 1,100 and we assume that no further price reductions may be expected. The Portuguese gas market has an HHI of approximately 4,300 and is much smaller compared to the Spanish gas market. After merging both markets, competition is likely to increase compared to the former Portuguese market.

The steps taken in the calculation the benefits by using the Cournot model on the Portuguese markets are shown in Figure 5.

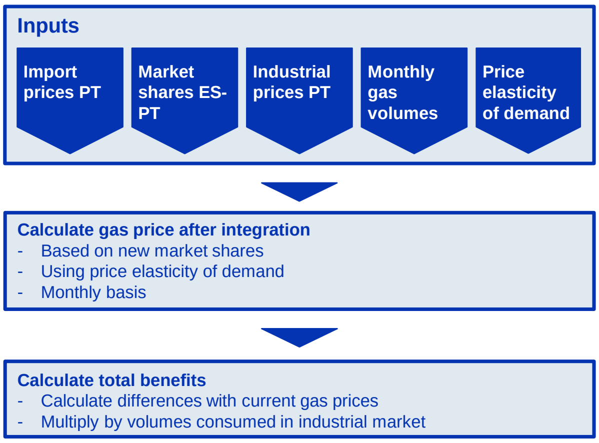


Figure 5: Steps in Applying the Cournot Model to ES & PT

In using this approach, it is implicitly assumed that the largest firm is setting prices and that its marginal costs are determined by the most expensive supply to the country as a whole instead of being firm specific. Also, the approach is quite straightforward and any results obtained are only indicative and should not be interpreted as an outcome of a fully-fledged competition analysis.

The basic assumption in using this approach is that margins can drop after the merger has taken place due to an increase in competition. Therefore, it is essential to understand the current prices charged to Portuguese consumers. At present, only prices charged by suppliers to three different industrial consumer groups are known[12]. Prices for other consumers are currently not known or at least not publicly available.

The prices charged are compared with pipeline import prices from Spain, which were regarded as the marginal cost of supply to Portugal. From this comparison, no conclusions regarding excessive margins could be drawn as differences between these prices were considerably small. On this basis, no benefits from an increase in competition can be quantified for at least those consumer groups for which price data was available.

2.3 Effects of Merging Spanish and Portuguese Gas Markets

This section treats the effects of a possible merger of Spanish and Portuguese gas markets. In contrast to the foregoing sections, this section mainly deals with more intangible effects that are difficult to quantify.

One of the first effects noticeable will likely be the increase in the liquidity on the wholesale market in Portugal. Currently, Portugal does not have a virtual point or other market place on which gas trade is possible and as such a transparent price setting mechanism is absent. A merger with the Spanish gas market, which has trade on the virtual point, in LNG terminals and storage sites, will likely increase liquidity in Portugal as well.

Benefits from an increase in the liquidity on the wholesale market are difficult to quantify. However, limited liquidity of wholesale markets may results in higher transaction costs. Therefore, bringing parties together and facilitate trading among them, which may be a result of market area merger, may lead to a reduction in bid-ask spreads which in turn leads to benefits due to lower transaction cost[13].

The creation of a single entry-exit zone leads to the ‘loss’ of certain interconnecting network points. Without any adjustments, this would lead to reduced revenues for one or both TSOs. Consequently, it will be necessary to re-set transmission tariffs in both countries, in order for the TSOs to generate the same revenues tariff resets as before.

Subsequently, this will on average lead to higher tariffs on the remaining entry and exit points as the same amount of revenue needs to be generated by fewer points. Furthermore, two choices can be made in resetting tariffs once the zones have merged[14].

First, tariffs can be calculated for each network separately. This implies that each TSO calculates network tariffs based on the remaining network points and its allowed revenue is allocated among them. This model has been applied in Germany when amalgamating the German market areas into either Gaspool or NCG. The advantage of this model is a.o. a reduced need for coordination and cooperation between the involved TSOs and is thus easier to implement.

[12] The consumer groups are indicated as I3A Low Pressure, I3A Medium Pressure, and I3B Medium Pressure and can be regarded as small to medium sized industrial consumers. Large industrial consumers directly connected to the high pressure grid are not included.

[13] Pfeifenberger, J.P., and Hou, D., “Transmission’s True Value”, Public Utilities Fortnightly, February 2012.

[14] THINK, “EU Involvement in Electricity and Natural Gas Transmission Grid Tarification – Final Report”, January 2012.

The second approach is the application of a fully harmonised tariff system between two TSOs. This means tariffs are not calculated for each network separately, but are calculated for a single network operated by a single company which is allowed to generate revenues equal to the sum of the separate TSOs. Therefore, increased coordination between TSOs and, possibly, inter-TSO compensation mechanisms are required. However, the advantage is the ability to design tariffs which provide locational signals for the entire market area and not for the separate networks. Designing tariffs for the two separate networks may result in suboptimal outcomes as, for example, scaling of tariffs to recover allowed revenues might create distortions when applied separately. Also, this approach will likely require an explicit inter-TSO compensation mechanism. This mechanism aims to ensure the revenue recovery of each TSO.

If the preferred approach to market integration will be a full market area merger, the interconnection point between Portugal and Spain will cease to exist. Presumably, this interconnection point is used in the gas supply agreements between Portugal and Algeria as the point of delivery. The abolishment of this interconnection point could result in a necessary change in delivery point in the gas supply agreement. In consequence, parallels can be drawn with mandatory bundling of capacity and the sunset clause and suitable arrangement will need to be considered.

2.4 **Conclusion**

In this section, the costs and benefits involved with a full market merger of the Spanish and Portuguese gas markets were calculated. The analysis shows that on a yearly basis there are likely moderate net benefits to be obtained. Furthermore, it is expected that benefits may increase if the Spanish and Portuguese TSOs manage to avoid additional investments whilst enabling market area merger and continuing to ensure reliable gas supplies to end consumers. The costs associated with alternative measures are generally expected to be lower than investing in new infrastructure, but will depend on the measure chosen and have not been quantified in this study.

When interpreting this result, it should be taken into account that the simplified analysis in this study has focused on those costs and benefits only, which could be easily quantified. Also, the chosen modeling approach is likely to underestimate the true benefits as it assumes a perfectly competitive market in both Spain and Portugal, which is arguably not the case at present. Moreover, we have only assessed the potential benefits in a specific market segment in Portugal, whereas possible additional benefits for instance for customers connected to high pressure off-takes have not been considered.

Furthermore, the analysis did only consider the gas sector on its own but not any wider impacts on the national economics, such as the electricity market. The Spanish and Portuguese electricity markets are already integrated and around one third of the electricity produced is generated by gas-fired power plants. As such, any inefficiency present in the gas market may be transferred to the electricity system. For example, high interconnection costs for transporting gas from Spain to Portugal may lead to efficient CCGT’s in Portugal moving closer towards the end of the merit order.

3 REPUBLIC OF IRELAND, NORTHERN IRELAND AND GREAT BRITAIN

Similar to the analysis concerning the merger of Spain and Portugal, an assessment of the potential cost involved in merging the markets of Ireland, Northern Ireland and the Great Britain is presented first. This section then continues with an assessment of the potential benefits and ends with a conclusion of the results obtained from both analyses.

3.1 Costs of Merging Republic of Ireland, Northern Ireland and Great Britain

3.1.1 Introduction and Major Assumptions

Our approach to assessing the costs of market area merger is dependent on the availability of data, especially regarding historic flows. Data regarding gas flows and especially gas demand figures for the gas markets in Ireland (RoI) and Northern Ireland (NI) was not separately available to us as no distinction was made between the supply of consumers in Ireland and Northern Ireland. This mainly originates from the Irish situation where Gaslink, the Irish TSO, also supplies part of Northern Ireland. The remainder of the gas demand in Northern Ireland is supplied by Premier Transmission Ltd. Therefore, we have considered the gas markets on the Irish islands to be integrated already and thus effectively consider an integration of the islands Ireland and Great Britain in the remainder.

Source: ENTSOG

Figure 6: Map of Irish and UK's Transmission Systems

This is a simplifying assumption as the regulatory authorities in Ireland and Northern Ireland are currently working together to establish All-Island Common Arrangements for Gas (CAG) to enable all stakeholders to buy, sell, transport, operate, develop and plan the natural gas market, north and south of the border, effectively on an all-island basis. One particular aspect of this all-island project is the goal of creating a single balancing zone for Ireland and Northern Ireland. As explained earlier, our approach to assessing the costs involved in merging market areas abstracts from balancing issues as it equates gas flows on a daily basis and neglects potential internal bottlenecks. Furthermore, it should be noted that the Common Arrangements for Gas Project is still under review by the Regulatory Authorities in both RoI and NI and the timing of the potential integration is as yet unclear. The following figure schematically displays the situation between Ireland and Northern Ireland.

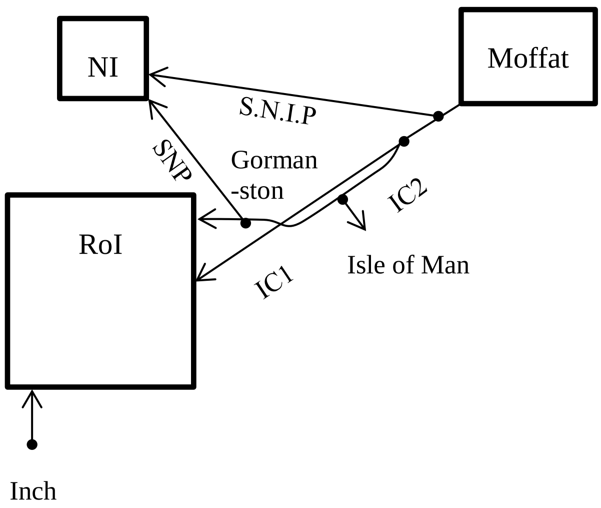


Figure 7: Schematic Representation of RoI and NI Interconnections

It is furthermore important to note that currently the onshore gas transmission networks in Ireland and Northern Ireland are physically not connected to each other. There is only a single interconnection to enable gas to flow from Interconnector II into the SNP. Only in exceptional emergency situations, gas may flow between the two systems. However, this requires on site manual intervention and results in an unmetered flow of gas.

3.1.2 Analysis and Results

Current Situation

Currently, Great Britain already provides a major share (approx. 93%) of the Irish gas demand through three interconnectors (Interconnector I & II and the SNIP) originating at the Moffat entry point in Scotland. The remainder is provided by domestic production and storage in Ireland.

Based on the data of 2012, four different scenarios were created. However, it turned out that, given the current Irish production levels, the supply of gas to Great Britain is impossible. Furthermore, the capacity available on the interconnectors was higher than the observed daily demands (342 GWh/day compared to 274 GWh/day). As the gas market in Great Britain is considerably larger than the Irish market it seems valid to assume that Great Britain could supply total peak demand in Ireland as sufficient amounts of gas should be available. Given the size of the interconnection capacity and based on the approach adopted, no additional interconnection capacity seems to be required. This conclusion is partially confirmed by Gaslink in its Winter Outlook 2012/2013 in which it states that the Moffat flows will approach capacity limits in the event of a 1-in-50 winter. Furthermore they also conclude that this implies that there will be limited system flexibility to accommodate within-day shipper re-nominations at Moffat. Also, towards 2020, peak demand is expected to rise to 405 GWh/day, which is more than the interconnectors can supply.

Given the results, it may be concluded that a market area merger does not necessarily require additional investments in infrastructure. However, it should be acknowledged that there will be limited system flexibility in Ireland and its dependence on Great Britain. The impact of this limited system flexibility, for example on the possibility to balance diurnal flows, requires more detailed modeling to assess for example whether the interconnectors' line pack is sufficient to accommodate this. Such modeling was omitted in our analysis as no detailed data concerning the networks was available.

Future Situation

In addition to the analysis above, which dealt with the current situation, it is important to take notice of the expected future developments in the Irish gas supply. In the year 2017/2018, new supply sources are expected to come on stream (Table 1), which could alter the demand and supply situation in Ireland significantly. At this point, Corrib is an interim entry point and will be a future source of supply. Also, any infrastructure and contractual arrangements related to the Corrib-project are already in place. In contrast, for both the Shannon LNG and the Larne storage projects no firm commitments and significant investments have been made nor exist any contractual arrangements related to these proposed projects. As such, these projects are still accompanied by uncertainty, whereas the Corrib project will commence.

Table 1: Expected and Potential Supply Sources to RoI and NI

Country	Entry	Supply Capacity (mscmd)	Supply Capacity (GWh/day)
Ireland	Inch	2.6	28.3
Ireland	Moffat (IC 1&2)	21.9	238.7
Ireland	Corrib	7.0	76.3
Ireland	Shannon LNG	11.3	123.2
Northern Ireland	Twynholm (SNIP)	6.2	67.6
Northern Ireland	Larne (storage)	22.0	239.8

Source: DNV KEMA, BGN

Minimum demand on a summer's day for RoI and NI combined is expected to be 13.9 mscmd[15] (152 GWh/day). Potential entry supplies to Ireland from Corrib and Shannon LNG, thus excluding flows from Great Britain, could equal 18.3 mscmd (199 GWh/day). Also, if both storages are assumed to be operated in a seasonal fashion and thus not supply during summer months[16] the total potential supply in 2017/2018 could be 4.4 mscmd (48 GWh/day) larger than minimum demand; in an integrated market, these flows could be shipped to Great Britain (Figure 8 – Version A). In turn, this could require the necessity for physical reverse flow on the IC 1 & 2, which is currently not possible (only virtual reverse flow is possible).

However, as the Larne storage site will consist out of cavern storages, it is likely not bound to any seasonal restrictions and can thus be operated in a more flexible manner. As such, the Larne storage site could be able to send out during a summer's day as well. Consequently, the required interconnection capacity could be higher. This is shown in Figure 8 – Version B. The case in which only Larne would be developed and Shannon LNG not, would also result in the possibility for a physical reverse flow (as shown in Figure 8 – Version C).

[15] mscmd is an abbreviation for million standard cubic meters per day.

[16] A similar outcome would of course be obtained if Larne was not built at all.

Furthermore, as mentioned earlier, for both Shannon LNG as well as Larne, no firm commitments have been provided and therefore both Shannon and Larne could be cancelled and subsequently none of the two would be built. In this case, the situation does not change from today's except for supplies from the Corrib field. In any case, supply capacity from Corrib would probably not suffice to enable the need for physical reverse flow as can be seen in Figure 8 – Version D.

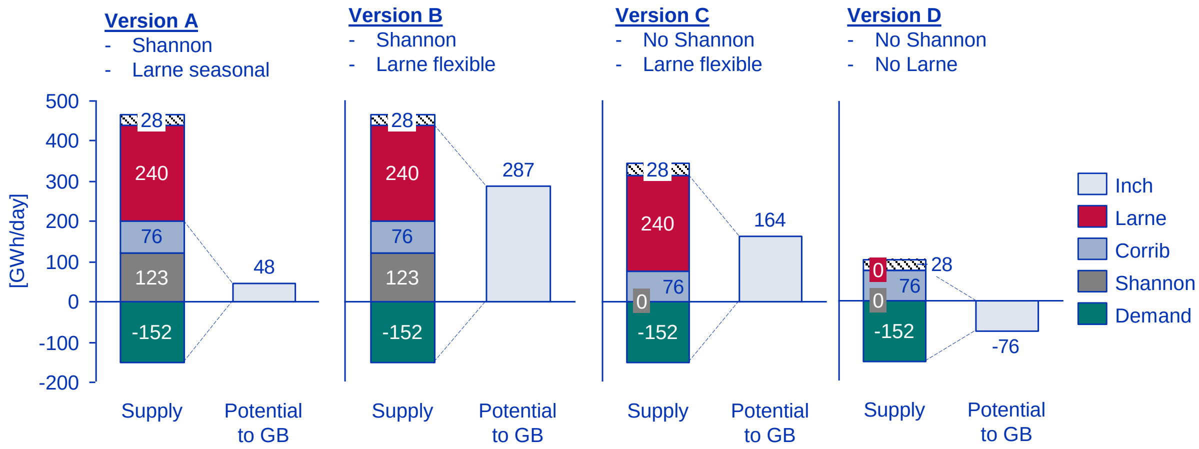


Figure 8: Supply and Demand Situation Summer's Day 2017/2018 for Different Scenarios

From the previous it becomes clear that under certain conditions a physical reverse flow in the IC system could be required. Inevitably, this would be accompanied by investments to enable these flows. Furthermore, in addition to a possible reversion of the physical flow, gas is currently odorised at transmission level in Ireland. In contrast, in Great Britain this occurs at distribution level. Hence, either deodorisation in Great Britain is required, or odorisation at distribution level should also be applied in Ireland.

The former option, deodorization, has not been implemented on an industrial scale in Europe to date, but merely as a pilot plant. GRTgaz has calculated that an industrial scale odorisation plant suitable to deodorize 300,000 m^3/h (or approximately 80 GWh/day) would require an investment of about 51M€. Furthermore, they estimate that the plant's operating costs would be between €2.7 and €10.2 per 1,000 m^3 of deodorised gas (i.e. €0.2 to €0.9 per MWh).

For the second option, i.e. installing odorisation plants at distribution level in Ireland, the estimated cost are between €150,000 and €250,000 per installation with a capacity of 5,000 m^3/h of gas flow, depending on technical requirements such as redundancy and safety measures. For safety reasons, odorisation at distribution level is generally a minimum requirement. Residential gas consumers are always supplied via distribution systems. The combined peak demand for RoI and NI in 2017/2018 equals 9.7 mscmd (Table 2). Furthermore, small industrial users and especially commercial users are sometimes connected to the distribution system as well. It is assumed that half of the I/C consumers are connected to the distribution system and their peak demand of 2.6 mscmd is subsequently added to the peak demand of residential consumers. In total, 12.3 mscmd would need to be odorised. A high-level estimation of the investment cost associated with installing the equipment required to odorise this peak demand equals 20.5 M€.

Table 2: Peak Demand (mscmd) Forecast RoI And NI 2017/2018

Sector	RoI	NI
Power generation	15.1	4.4
Industrial / Commercial (I/C)	5.6	n/a
Residential	6.1	3.6
Total	26.8	8
Relevant for odorisation	8.9	3.6

Source: CER, NIAUR (JGCS 2012)

In the Market Consultation for Physical Reverse Flow at Moffat[17], National Grid and Gaslink provide a high-level preliminary estimate of the cost involved for accommodating a reverse flow of 3.5 mscmd through the interconnecting pipelines. Besides (de)odorisation costs, National Grid and Gaslink also foresee additional investments such as compression in Ireland to transport gas to Great Britain. National Grid's and Gaslink's estimates confirm the numbers presented above and are shown in Table 3.

Table 3: Order of Magnitude Cost Estimates for Physical Reverse Flow at Moffat

Project	Cost (M€)
Onshore compression on the island of Ireland	90
Install odorisation in Ireland	25
Deodorisation plant at Moffat	50
Reinforcement of pipelines transporting gas west to east in Ireland	45
Reconfiguration costs at Moffat AGI	17
Twynholm AGI bi-directional modifications	4

Source: National Grid, Gaslink

In summary and based on the information presented in Table 3, a merger of the gas markets on the Irish and British Isles would be accompanied by significant investments with a high estimate of 231 M€. This would translate to annual costs of about 19.6 M€, excluding any operating cost for, for example, deodorisation and compressor station upkeep.

[17] National Grid and Gaslink, "Market Consultation for Physical Reverse Flows at Moffat", 9th August, 2011

3.2 Benefits of Merging Ireland, Northern Ireland and Great Britain

Above it was specified in which categories the benefits from a market area merger may arise. As the GB gas market is regarded as the most developed and liquid in Europe, we focus on the potential benefits in both categories on RoI and NI. First, we provide a short description of the Irish gas market.

The Irish gas market can be divided into three distinct segments:

1. Large Daily Metered (LDM): LDM segment consists of power stations and large industrial consumers. Most of the 16 LDM take care of their own gas shipping activities by purchasing gas directly from the wholesale market and thus the LDM segment is non-regulated.

2. Daily Metered (DM): The DM segment is made up out of approximately 240 industrial and large commercial consumers, but with a smaller annual consumption than LDM consumers. As the LDM segment it is non-regulated.

3. Non Daily Metered (NDM): Residential, commercial and small individual parties consuming less than 5.55 GWh annually comprise the NDM segment. The so-called "domestic market" consisting of residential NDM consumers is the only segment still subject to price regulation. CER continues to monitor whether predetermined deregulation criteria are met before ending price regulation in the residential sector.

The above shows that a large share of the Irish gas market has been deregulated as CER envisaged sufficient competition in these segments. Also, gas prices in Ireland are already coupled to NBP prices; this basically implies that both markets are already integrated. Hence, it may be expected that any benefits from an increase in competition created due to the merger could be limited.

Although connected to NBP, prices in Ireland are increased by transportation costs incurred for use of the Interconnectors 1 & 2. The short to midterm developments mentioned above could reduce gas flows via the interconnector. As stated by the Commission for Energy Regulation (CER/12/087) "… this will increase the unit IC entry tariff, potentially significantly so. This higher IC entry tariff would, in turn, push up the wholesale price for gas in Ireland. This would be inefficient and damaging to both consumer interests and Ireland's energy competitiveness".

In this case, the rare situation occurs in which an increase in competition increases prices. This goes as long as the gas flows from Great Britain set the price. It may be assumed that the Shell consortium operating the Corrib gas field will be a price follower, given the inflexibility of most gas fields.

In any case, a market merger which factually leads to the elimination of the interconnectors as separate entry/exit points would cancel this effect and gas prices may actually slightly decrease. Today, with two separate markets, gas prices in Ireland are NBP with the cost of the interconnector, but are recovered over less than 100% of local demand. Hence, local production will benefit as it can charge slightly higher prices. Conversely, after a merger, the market price in Ireland should be NBP. Irish consumers will still have to pay for the interconnector, but these costs would now be distributed to 100% of demand, i.e. the specific cost will become slightly lower.

To illustrate the above, assume that demand in Ireland is close to 5.1 bcm per year and that the allowed revenue for the interconnector system equals 50 M€ per annum. Currently, this revenue is recovered by, say, 93% of local demand, i.e. the share supplied through the interconnector system. Hence, the specific costs are around 1.05 €cent/m^3. However, if the revenue was to be recovered by 100% of local demand, specific costs would drop to 0.98 €cent/m^3. Therefore, prices may rise with approximately 0.07 €cent/m^3. Therefore, on a yearly basis this would amount to 3.76 M€. This figure would be larger if the share through the interconnector system drops (e.g. with an 85% share the number would rise to approximately 5.1 M€).

The question remains however whether a market merger is the most suitable way for solving the issues related to the interconnector's revenue recovery especially given the potential costs associated with such a merger in the near future. Also, it should be noted that the IC tariff is currently already the subject of judicial review.

3.3 Conclusion

In the previous sections we have assessed the costs and benefits associated with a possible merger of the gas markets of Great Britain, Republic of Ireland and Northern Ireland. Such a merger may lead to significant costs in the short to mid-term, which are mainly related to the possibility of physical reverse flows from the Republic of Ireland and Northern Ireland to Great Britain.

The gas market of Great Britain is generally regarded as the most liquid in Europe with a low market concentration. Hence, any benefits from an increase in competition are expected to primarily occur in the Irish gas market instead of in the GB market. Furthermore, Ireland sources almost all of its gas on the NBP in Great Britain. As such, the Irish market is basically integrated with the GB market already. Although some benefits can theoretically be expected from a merger due to an expected fall in gas prices, it may lead to a potential rise in transmission tariffs of the interconnector system. The latter may result from a different allocation of the interconnector's costs to entry and exit points in a combined system. This issue is principally a cost allocation problem and may therefore be regarded as a side-effect of a market merger.

Overall, it seems uncertain whether a merger of these markets will lead to any tangible benefits. Instead, it may be more beneficial to consider other, less rigorous alternatives for promoting integration of the individual markets.

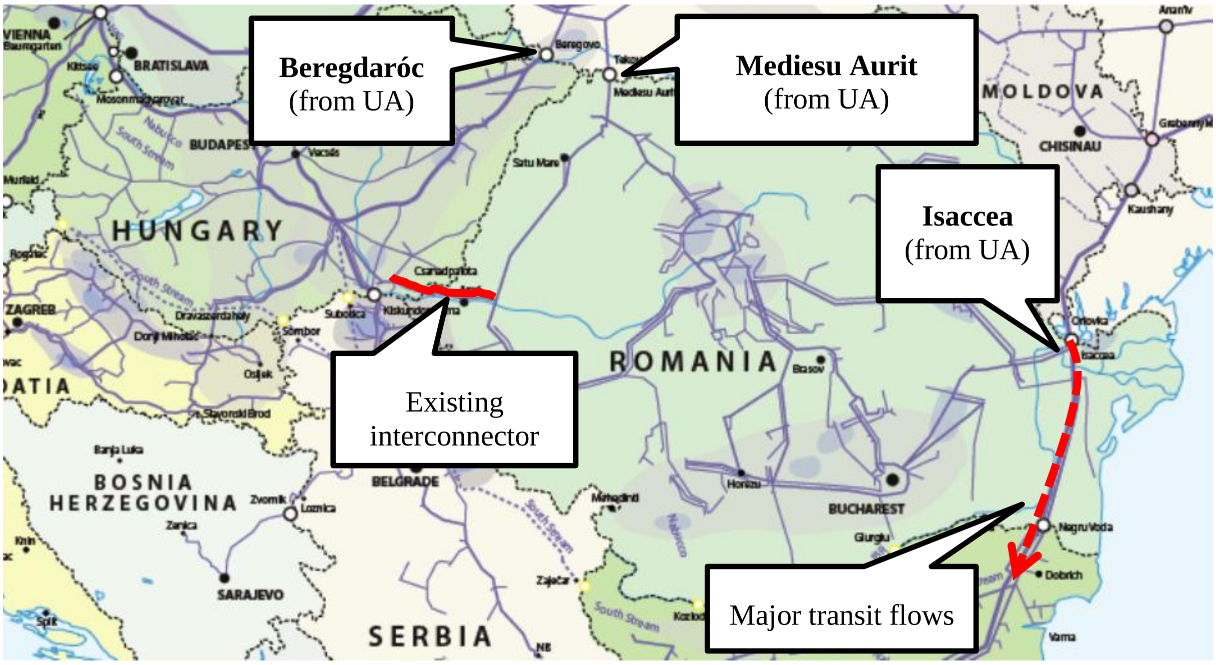
4 HUNGARY – ROMANIA

The third combination of countries selected for assessing the costs and benefits is Hungary and Romania. First the costs associated with a possible merger are estimated, before the potential benefits of merger both markets are treated.

4.1 Costs of Merging Hungary and Romania

4.1.1 Introduction

At the moment, the networks of Hungary and Romania are connected at the Csanadpalota interconnection point on the Arad - Szeged pipeline. The pipeline was established recently and was inaugurated in 2010. Its capacity is 46 GWh/day (~200,000 m^3/h) and cost 68 M€[18]. It is used to transport gas from Hungary to Romania. Under certain conditions and with certain modifications on the Romanian side, gas can flow in the opposite direction as well. Due to this interconnection, Romania is now physically connected to the other parts of the European network and therewith lowers its dependency on Russian or Ukrainian supplies which currently supply 20-25% of Romanian demand.



Source: ENTSOG

Figure 9: Map of Hungarian and Romanian Transmission Systems

In line with the adopted approach, it is assumed that an entry-exit system has been established in both countries. With regard to Romania, this entry-exit system thus also includes gas transiting from Ukraine to Bulgaria.

[18] This equates to 1.34 M€ per GWh/day or just under 23 €/(m * inch).

4.1.2 Analysis and Results

The use of the approach described above, which is based on the scenarios developed as explained in the slides annexed to this report[19], results into an additional interconnection capacity in the direction Hungary to Romania of 36 GWh/day; this is in addition to the existing capacity. In the opposite direction from Romania to Hungary, 308 GWh/day (or 1,244,000 m^3/ h) would be required. This is approximately six times the current interconnection capacity available in the opposite direction from Hungary to Romania.

As mentioned before, the existing pipeline interconnection can be modified to accommodate reverse flow (i.e. from Romania to Hungary). If we assume that this could be achieved under relatively small costs, still about 1 million m^3/h needs to be able to flow in the opposite direction. A new pipeline parallel to the existing one would need to be 36 inches in diameter[20]. Based on the assumptions provided above (see Section 1.1.2), the cost of such a pipeline can be estimated at around 128 M€.

Besides a new pipeline, a new compressor station would presumably need to be built as well. The required compression power equals 7.9 MW. The costs associated with this compressor station are approximately 17.1 M€.

Hungary and Romania are both supplied by Russia through Ukraine. Hungary receives gas from Ukraine at Beregdaróc and Romania at Mediesu Aurit and Isaccea. The latter point is located at the east of Romania and mainly used for transit flows to Bulgaria and Turkey. Due to the capacity of this transit line and the distance to the Beregdaróc interconnection point, it is unlikely that gas can be swapped between these two points. However, it is foreseen that gas can be swapped between Beregdaróc and Mediesu Aurit. Therefore, when coordinating with Ukrainian TSO Ukrtransgaz, the required interconnection capacity in the direction Romania to Hungary could be reduced to 199 GWh/day, taking into account the accommodation of physical reserve flow on the existing pipeline. This would require a 32 inch pipeline costing about 111.1 M€; the compressor station would cost 15.0 M€.

In sum, the cost estimated with a merger of the Romanian and Hungarian gas markets would be 126 M€ and 145 M€ depending on swap possibilities with Ukraine. On an annual basis, this would be equal 10.7 M€ to 12.3 M€ excluding operations and maintenance costs. Operations and maintenance costs are estimated to be between 2.36 M€ and 2.78 M€ annually. In total, annual expenses range from 13 to 15.1 M€.

Thus far, the analysis adhered to strictly having freely allocable capacities in place. In Romania, a large part of the pipeline system is used for transiting gas from Ukraine to Bulgaria. For this particular part of the network, locational restrictions may be applied in order to reduce the interconnection capacity required. It is important to note that the interconnection capacity required, in the direction Romania to Hungary, as calculated above, was restricted by Hungary’s ability to absorb these volumes and not so much by the volumes Romania could export. Locational restrictions will restrict the volumes Romania can export and its effect may thus be limited in this particular case. Nevertheless, when taking the transit flows out of the equation, the required interconnection capacity drops from 199 GWh/day to 115 GWh/day (i.e. if the possibility to swap with Ukraine is taken into account as well as the modification which allows for reverse flow on the existing interconnection).Thus, an investment amounting to 80 GWh/day is omitted by applying locational restrictions. The savings accompanying these restrictions are about 53 M€, or 4.5 M€ per annum on average.

---

[19] The scenarios developed were based on assumptions resulting from an analysis of historic data. As such, these scenarios reflect a possible outcome and should not be considered as a fact.

[20] Assuming inlet pressure of 63 bar and minimum outlet pressure 45 bar. Distance is equal to the existing pipeline of 109 km.

4.2 Benefits of Merging Hungary and Romania

Currently, the majority of Romania's gas market is subject to regulated end user prices. Gas prices are set for a mix of domestically produced gas and imported gas, which is said to be priced at three times the price of domestically produced gas. Furthermore, the share of domestically gas produced is primarily allocated to household consumers, which are supplied with domestically produced gas for 94% of their total demand. The share of domestically produced gas used for serving industrial consumers is 61% of this segment's total demand (Figure 10).

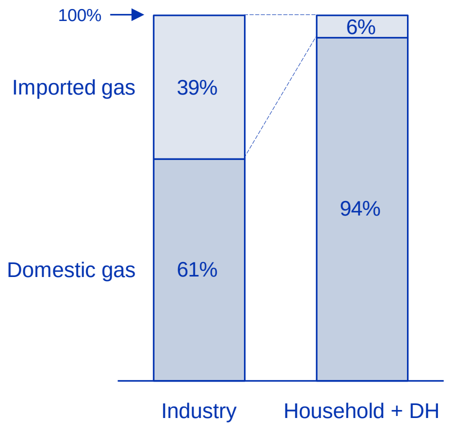


Figure 10: Share of Gas Allocated to Household and Industry by Source

However, Romania has committed to the World Bank, IMF and EC to deregulate its gas market over the next two to four years depending on the market segment. For industrial users, it is envisaged that gas prices will be deregulated by December 31st, 2014. The market for household consumers and district heating companies will be fully deregulated by December 31st, 2018[21].

Prices in both markets will steadily increase over the period towards the moment of deregulation. In the first two years, households will face a 10% p.a. increase and 12% p.a. in the last three years. The following figure shows how prices are planned to be increased for all segments.

[21] Natural Gas Europe, "Romania to See Gas Price Increase", 02-06-2013.

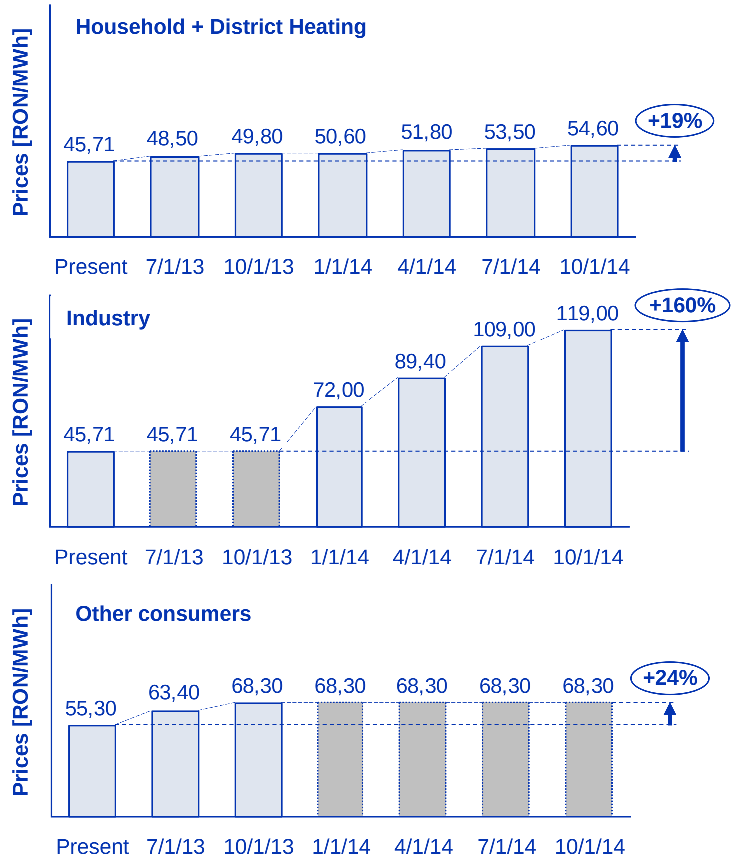


Figure 11: Stages to Deregulation of Different Market Segments in Romania

Due to the current regulated prices and subsequent deregulation, it is impossible to quantify any potential benefits from a market merger. However, Hungarian consumers might benefit from a merger with Romania. This can be explained with help of the following fictitious and conceptual figure (Figure 12).

Figure 12 shows the supply and demand (vertical lines) curves of two different markets: one which has a relatively low price (A) and the other a somewhat higher price (B). In the current situation, consumers spend 55 monetary units to purchase goods to satisfy their demand in market A and 96 monetary units in market B. Together, all consumers of market A and B spend 151 units (= 55 + 96). In the leftmost graph, both markets are merged into a single market. Consumption is again 22; however, total amount spent to satisfy demand is 132 units (= 22 * 6). Hence, total benefits for consumers equal 19 monetary units. However, at the same time, total loss for producers equals 19 monetary units as well. A similar concept might apply to the integration of Hungary and Romania.

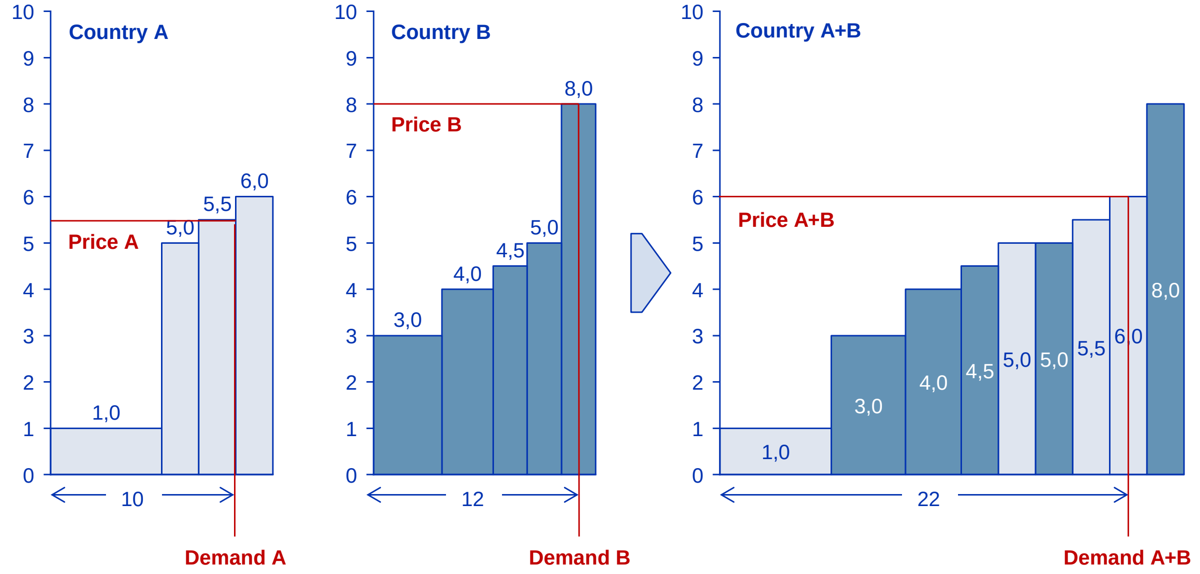


Figure 12: Potential Benefits from Market Merger with Different Marginal Offers

The abovementioned example only applies to situations in which the marginal offers of supply for both countries are different. In the case marginal offers are equal; these benefits do not occur (e.g. Figure 13, which shows that in both cases the total amount spent in 121). This means that, as long as both countries receive their marginal supply from Ukraine, one could assume prices to be very similar. This would reduce any of the above explained benefits. At the same time though, the need for additional interconnection capacity would presumably be strongly reduced as well.

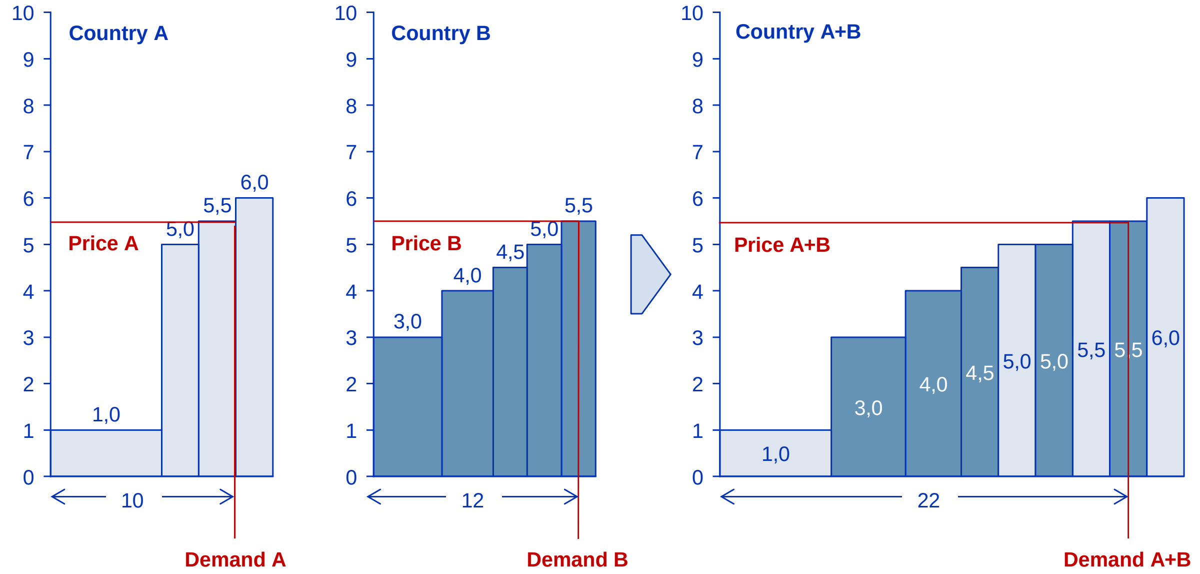
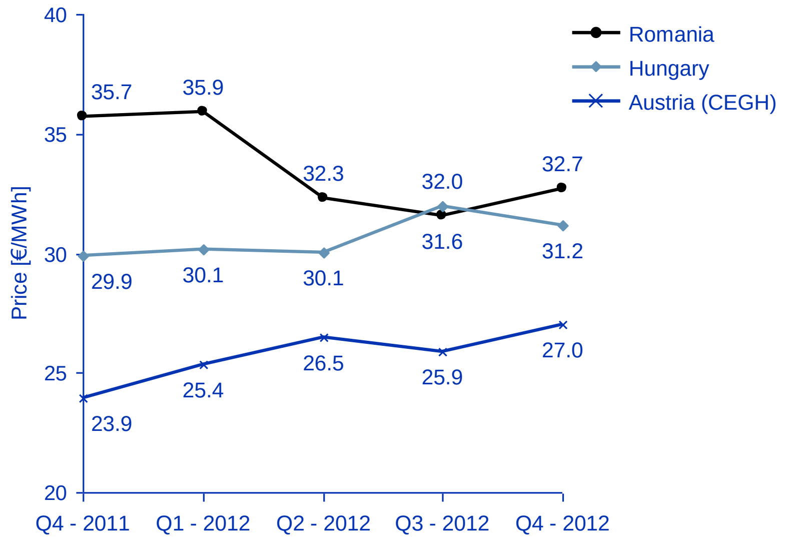


Figure 13: Potential Effects from Market Merger with Similar Marginal Offers

Figure 14 below shows prices for Russian gas delivered to both Hungary and Romania. Also shown are prices at the CEGH gas exchange in Austria, which we consider as benchmark prices for supplies from Western Europe to Hungary. As can be seen from the figure, prices for Russian gas are higher compared to the prices for gas traded at the Austrian exchange. This means that Russian gas was the marginal source of supply to both Hungary and Romania. Thus any integration benefits that may have arisen would likely have been relatively small.



Source: EC, CEGH

Figure 14: Average Border Prices of Russian Gas to Romania and Hungary and Average Prices for CEGH

4.3 Conclusion

In the foregoing we have assessed the costs of merging the Romanian and Hungarian gas markets. As the current interconnection capacity is rather limited in relation to the size of both markets, consequently large investments may be required to enable a full market merger and, at the same time, offer the same level of reliability of supply to end consumers. However, several ways to reduce the required interconnection capacity have been identified. For example, modifying the existing interconnection to accommodate physical reverse flow could be a first step. Secondly, arranging the possibility to swap gas between Hungary and Romania with the Ukrainian TSO Ukrtransgaz could further reduce the needs for interconnection capacity. Finally, the introduction of locational restrictions on the transit section of the Romanian network would be a third option to reduce interconnection capacity and associated investment requirements. Nevertheless, whilst these options may reduce the need for capacity, they would not suffice to completely eliminate it (see also Figure 15).

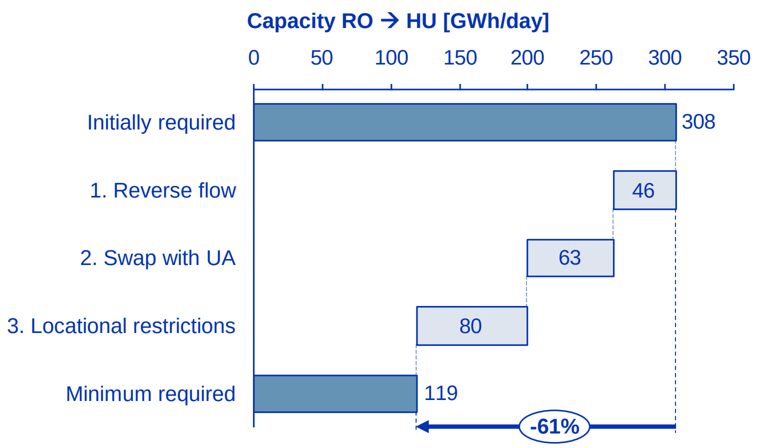


Figure 15: Options to Reduce Interconnection Requirements between Romania and Hungary

The potential benefits that may arise from a market merger between Hungary and Romania cannot be quantified at this stage. This mainly has to do with the current situation of the Romanian gas market and its forthcoming deregulation; this process makes it very difficult to estimate any potential benefits. A merger of both markets may thus be regarded as premature at this point, as it is unclear how the Romanian market will evolve during the next few of years as a result of liberalisation and the introduction of the European network codes.

5 NON-INVESTIVE ALTERNATIVES TO INTERCONNECTION CAPACITY

In the sections above, we have suggested that in certain cases non-investive measures may be a suitable alternative to investing in new infrastructure in order to able a single market. In the case of Romania and Hungary, we also showed the impact some of these measures may have. In this section, several of these non-investive measures are discussed in further detail. They are grouped in administrated measures and market-based instruments.

As explained, administrated measures can be used to restrict network users' flexibility or to mandate changes to the planned use of the network. Market-based instruments are designed to incentive network user to adjust or avoid entry/exit flows which may lead to operational problems. Arguably, in a liberalised market, preference should be given to market-based as they are based on voluntary agreements between the TSO, on the one hand, and shippers or other infrastructure operators, on the other hand.

The following table provides an overview of some potential mechanisms that are available for relieving potential congestion. Furthermore, the table specifies whether the mechanism belongs to the group of administrated measures or is a market-based instrument. Also, in case the mechanism belongs to the group of market-based instruments, the table indicates the counterpart for the TSO.

Administrated measures come largely free of charge to the TSO, with the exception of for example a reduction in tariffs for interruptible or restricted capacities. Market-based instruments are generally accompanied by remunerating counterparties for the actions taken.

Apart from the difference between administrated and market-based measures, the mechanisms can also be grouped by the type of product and/or service to which they are related. Two distinctions can be made: the mechanism is either related to the allocation and use of capacity rights or the mechanism is directly linked to trading gas and/or the nominations submitted by network users on a daily basis.

Table 4: Potential Mechanisms to Relieve Congestion

	Administrated Measures	Market-Based Instruments	
Counterparty	Shippers	Shippers	Infrastructure operators
Capacity	• Interruptible capacities • Locational restrictions • Limited allocability	• Capacity buy-back	
Commodity / Nominations		• Locational trades • Flow commitments	• Re-routing of flows

Source: DNV KEMA

5.1 Administrated Measures

5.1.1 Use of Interruptible Capacities

A very basic approach to reduce the need for investing in additional infrastructure is the introduction of interruptible capacities. Interruptible capacities are already widely applied in the European gas markets, in order to provide as much capacity to the market as possible whilst maintaining the ability of the TSO to guarantee system integrity. Introducing interruptible capacities would imply degrading currently firm, preferably unsold capacity to interruptible capacity in order to account for those situations in which the current interconnection capacity is insufficient and congestion problems occur.

Given the perspective, this type of interruptible capacity would be somewhat different from the interruptible capacities as they are currently offered by TSOs. In many instances, these interruptible capacities stem from the non-simultaneous usage of firm capacities, which allows for slightly overselling the technically available capacity and offering it as interruptible. Hence, the probability of interruption is often based on historic flows and/or nominations. This immediately results in a practical difficulty of introducing interruptible capacities for facilitating a market merger. As there is no historic data concerning nomination and/or flows for the merged situation, it is impossible to calculate the associated probability of interruption.

Another option closely related to interruptible capacities is the concept of conditional capacity. In essence, the TSOs do not interrupt capacity, but would redefine the capacity product such that it may only be used under certain circumstances. As such, the network user’s use of the conditional capacity product would be restricted beforehand to those situations which would not lead to an interruption. The advantage of this type of capacity is the clarity it provides to network users concerning the firmness of the product as it delineates it usability in advance. In the case interruptible capacities are used for enabling the market merger, the specific situation in which the network user is interrupted in unclear and depends on an undefinable probability.

Finally, a third option could be considered. This time the TSO would withheld capacity from the market and make it available in the short term (e.g. daily basis). The uncertainty concerning the use of the capacities at each network point may be reduced closer to the moment of actual delivery. Therefore, the TSO should be in a position to predict the risk (and potential impact) of physical congestion more precisely. The TSO may thus be able to sell this capacity as additional firm capacity.

5.1.2 Locational Restrictions / Limited Allocability

Locational restrictions may be introduced in order to increase the TSOs ability to forecast flows and to limit the number of possible combinations of entry and exit flows. In its simplest form, a locational restriction can be regarded as point-to-point obligations within an entry-exit system. This option was proposed in the cost assessment of merging the Romanian and Hungarian gas market earlier in this report.

However, locational restrictions may be defined less strictly and not relate to a combination of specific points, but to specific parts of the overall market area as well. Likewise, network users may be allowed to nominate deviating flows, e.g. to or from the virtual point, but on an interruptible basis only. In Germany for example, TSOs offer “Dynamically Allocable Capacity” for which capacities are considered firm as long as they are used for balanced transportation between specified entry and exit points. In case network users nominate different flow patterns, the 'unbalanced part' of the corresponding nominations becomes interruptible. This approach thus limits the variety of flow scenarios to be considered in the TSO's flow simulations and thus decreases the amount of capacity which needs to be reserved for contingencies.

5.2 Market-Based Instruments

5.2.1 Capacity Buy-Back

Another option for resolving congestion is the application of capacity buy-back. In contrast to the two approaches defined above, capacity buy-back is a market-based approach. In case of congestion, the TSO would attempt to buy capacity back from the network users on a short term basis. This would usually be on a daily basis, but given the circumstance, capacity could also be bought back for longer periods such as on a weekly or perhaps monthly basis.

One issue with the capacity buy-back mechanism is that it cannot guarantee that the network users sell back the capacity to the TSO and might thus not resolve the congestion problem. Another approach would thus be to oblige network users to offer capacity to the TSO when being asked.

In the UK, capacity buy-back schemes have already been applied for a long time. National Grid uses this mechanism for selected entry capacities, and the procurement is organised as a long-term tender with up to 42 months lead time. During the tender, network users offer the option to give back their capacity rights for a specified number of days during a predefined period. Thus, the TSO is contracting an option which can be exercised in the short-term, i.e. when required. Shippers are remunerated through a holding payment and an exercise price.

Capacity buy back will force the TSO to repurchase some of the capacity it has sold to network users. The price for which these network users will offer the capacity is unknown, but it may be expected that they at least want its market value. This market value may be relatively high when the problem occurs. Consequently, the TSO may be faced with significant costs at certain times and thus the regulatory treatment of buy-back costs would need to be clearly defined.

5.2.2 Locational Trades

In contrast to the mechanisms previously discussed, locational trades do not relate to the definition and use of capacity rights, but are based on transactions for gas. With a locational trade, the TSO basically trades in a specific location of the network in order to resolve a congestion problem. To this end, it may purchase gas in one location and/or sell gas in another location. While doing so, it should assure that the overall balance of the system is of course maintained.

The trades made by the TSO at one side of the physical congestion do not necessarily have to be related to the trades made at the other side. As such, it may engage into the purchase of gas at one side of the constraint with one of more network users, while selling gas at the other side to other network users. The results of these trades should be a net flow against the physical congestion. In addition, in certain situations, it might be sufficient to only trade on one side of the physical congestion; for example, in those cases where network users are unable to re-balance their own portfolio by opposite transactions or nominations in the same area.

Another option closely related to locational trades would be restructuring locational trades in the form of obligations to re-nominate. In this case, the TSO arranges with the network users that it may oblige them to adjust their initial nominations by a certain amount in order to relieve congestion. The network user would be free to re-balance his portfolio in other ways. Using this approach, the TSO does not make any transaction in the gas market, but would merely pay the network users for a desired change in the initial nominations. Transactions in the gas market are left to the network users in order to restore its balance.

As with capacity buy-back, the TSO is required to engage in direct transactions with market parties which may result in additional costs for the TSO. Therefore, it is important to clearly define the regulatory treatment of the resulting costs to reduce the TSO's risk while at the same time providing suitable incentives for an efficient use.

5.2.3 Flow Commitments

Flow commitments can be an agreement between a TSO and a network user in which the network user agrees not to exceed or not to fall below a predefined flow at a specific entry or exit point. A different type of flow commitment could also be the obligation imposed on network users to offer a predetermined change in the initial nomination. In both cases, the flow commitments may be applied to very specific locations, such that they can be applied to specific parts of the network where the congestion occurs.

Instead of engaging in the daily gas market as would be the case for locational trades, flow commitments are generally purchased by the TSO by means of a tendering procedure. These flow commitments may be contracted for a couple of months or even a full year. In response to such a tender, network users may submit offers specifying the location, the amount and the remuneration to be paid by the TSO. The remuneration could be a fixed price or a combination of a fixed holding payment and an additional strike price to be paid by the TSO in case the flow commitment is actually used. The latter case resembles the payment scheme as applied in the British gas market for capacity buy-back.

The use of flow commitments would obviously require the introduction of public tenders, including the preparation of all relevant tender rules and framework agreements. Similar to the other market-based mechanisms discussed before, it would in addition be necessary to define the regulatory treatment of any resulting costs.

5.2.4 Re-Routing of Gas Flows

An additional form of resolving constraints could be the re-routing of flows through neighboring networks. This mechanism requires the cooperation between two or more TSO and has been applied in assessing the required interconnection capacity between Hungary and Romania earlier in this report. In this case a swap with Ukraine could be executed in order to reduce flows across the interconnection. Generally, all nominations made by network users are still fulfilled, although the physical flows would no longer match the nominated entry and exit flows. However, the overall balance of each network would remain unchanged and no ownership transfer of gas would be required.

When re-routing gas flows, the TSO experiencing congestion would contact its neighboring network operators and request to re-route certain flows in order to reduce congestion. Of course, the neighboring TSO would need to be able to accommodate this request; this would be dependent on the specific situation in his network. Therefore, the neighboring TSO might not always be able to re-route these flows and therefore, this concept can only be applied on an interruptible basis.

The main advantage of this approach is probably the relatively low costs involved. As all nominations can be accommodated, no remuneration for network users is required. The only costs involved are the incremental costs of compression if this is even required. Therefore, this mechanism can be introduced by an operational agreement between the TSOs. In order to avoid (structural) disadvantages for certain TSOs and to provide incentives for mutual assistance, it might however be desirable to agree on some form of compensation, in order to remunerate individual companies for a less efficient use of their own network.

6 ALTERNATIVES TO MARKET AREA MERGERS

In the foregoing we have discussed the cost and benefits of a market merger, i.e. of creating a single entry-exit zone. Besides a fully-fledged market merger, alternatives to facilitate market integration exist as well. The following figure shows some possible alternatives.

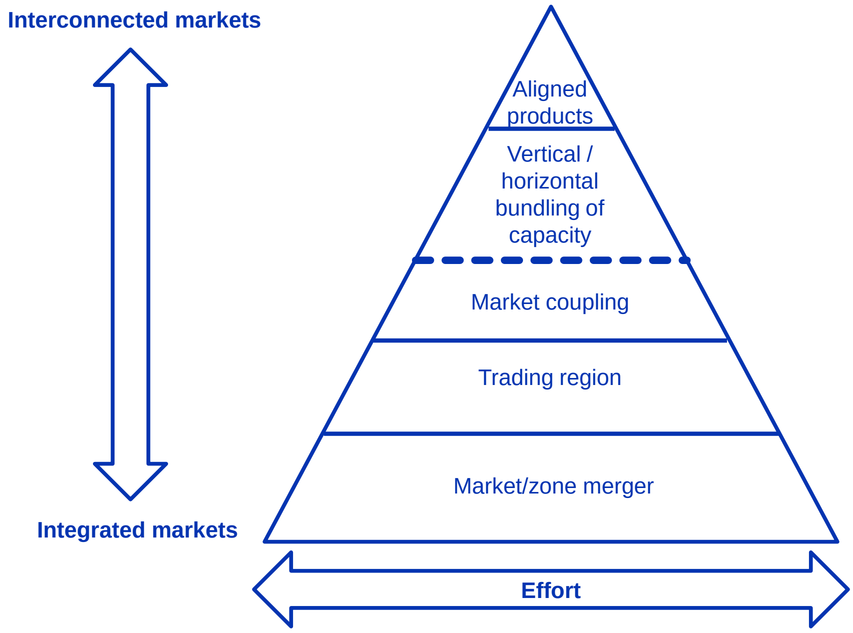


Figure 16: Alternative Concepts for Market Area Mergers

The figure should be interpreted in the following manner:

- The pyramid shows different alternatives that may be envisaged for creating integrated markets.
- The vertical axis shows the level to which an alternative may enable the integration of markets. The axis ranges from separate interconnected markets to fully integrated markets and thus shows the effect, i.e. the level of integration that an alternative offers. The different alternatives are sorted based on their ability to facilitate market integration. For example, market area or zone mergers will warrant market integration by definition, just as a trading region would. However, market coupling results in integrated markets for most of the time but there may be situations in which markets are split. Bundling and aligning of products will ease the integration of markets, but cannot ensure it.
- Horizontally the effort involved for implementing the alternative is shown. The wider the corresponding part of the main triangle in the centre of Figure 16 is, the more efforts are required. Again, the figure is conceptual and merely addresses the differences between the alternatives in relation to each other and for an ‘average situation’[22]. To which extent the effort

[22] As such, the actual effort involved for the different concepts could differ more from each other than indicated by the width of each section. For instance, the implementation of a trading region or a full market merger would

required per alternative differs from another alternative depends on the specific situation. Furthermore, effort, being a fairly generic term, may refer to both the physical or infrastructure related requirements as well as to the coordination required between different parties.

The remainder of this section provides a description of these different alternatives.

6.1 Aligned Products

The first effort to accelerate market integration would be to offer products and services which are aligned at both sides of the border. This would mean that similar capacity products are offered by the TSO's at interconnecting network points. The development and implementation of the European network codes, predominantly CAM NC, should assure aligned products at interconnection points.

The concept of 'aligned products' has been place atop of the pyramid in Figure 16. Although similar and harmonised products will facilitate cross-border trade and thus integration of two adjacent market areas, they cannot guarantee it.

6.2 Vertical and/or Horizontal Bundling of Capacity

The second alternative concept that could support the integration of gas markets are bundled capacity products. In contrast to merely aligning products at both sides of the border, bundled products are specifically designed to facilitate cross-border trade by removing potential barriers, which leads to a reduction in transaction costs and a more efficient use of cross-border capacity.

Bundled products may be distinguished in three different types:

1. Vertical bundling

   Bundling capacity products vertically entails selling cross-border entry and exit capacity as a single product. Hence, network users are not required to book exit from the supplying market area and entry into the receiving market area separately. Therefore, vertical bundling lifts potential barriers, such as the availability of equal entry and exit capacity volumes on both sides of the border, and reduces the need for network users to book capacity from different parties. Whilst the latter benefit may be of limited importance (i.e. largely limited to reduced transaction costs) the former may be critical in terms of ensuring equal access to cross-border capacity.

2. Horizontal bundling

   When capacity products at, for example, different physical entry or exit points are not sold separately but merged into a single product we refer to horizontal bundling. This means that no physical differentiation exists and that several physical interconnections are combined into a virtual interconnection point.

---

normally be more challenging than that of a horizontally bundled product. The dotted line indicates that implementing the first two concepts is probably significantly less demanding than the last three.

3. Virtual point to virtual point products (VTP to VTP product)

   A product for moving gas from one virtual point to another virtual point basically combines vertical and horizontal bundling. A VTP to VTP product thus reduces the need to specify individual and/or separate entry and exit points but allows for selling gas from one virtual point to another virtual point.

Many of these concepts are already applied in European gas markets today. For example, virtual interconnection points are already applied between both PEG's in France, between Belgium and Luxembourg, and between Portugal and Spain. Furthermore, the CAM NC requires TSOs to offer all firm capacity as bundled capacity on both sides of an adjacent cross-border point. The most recent development in this respect is the establishment of the PRISMA platform for offering capacity products in compliance with the CAM NC. The PRISMA platform combines several formerly existing capacity booking platforms of TSO in seven European countries, i.e. Capsquare, Link4Hubs and TRAC-X. To date, the TSOs of Austria, Belgium, Denmark, Germany, France, Italy and the Netherlands have joined PRISMA.

6.3 Market Coupling

Market coupling is generally understood as the allocation of cross-border capacities by means of an implicit auction, i.e. through a market-based mechanism (auction); and by simultaneously creating a transaction for commodity. Therefore, market coupling is generally described as the combination of commodity trade with (the utilisation of limited) transmission capacity and aims to manage limited transmission capacity more efficiently as well as to increase price convergence between two or more commodity markets in different areas.

Instead of using explicit auctions, or other means for network users to acquire transmission capacity separately, market coupling thus involves the use of implicit auctions. Implicit auctions allocate transmission capacity based on bids and offers in the commodity markets made in two adjacent markets. By joining supply and demand curves of these markets, the amount of transmission capacity required to optimise welfare (i.e. consumer and producer surplus) can be derived and transmission capacity is subsequently allocated. This means that, given sufficient interconnection capacity, prices between two adjacent markets will converge to a single price and the two market areas will be fully integrated. Furthermore, any inefficiencies arising from a mismatch between capacities contracted in advance by specific parties and the allocation of capacities as would result from joining two or more market are negated (the "coordination problem").

Market coupling is said to have certain advantages compared to explicitly allocating transmission capacity. As mentioned before, market coupling integrates the two, usually consecutive, steps of contracting capacities and trading on the commodity market therewith assuring an automatically integrated market and an optimal use of interconnection capacity in an economic sense. Furthermore, the fact that interconnection capacity's market value is identical to the price difference between the adjacent markets is another advantage. In relation to this, any potential congestion rents only arise if transmission capacity turns out to be insufficient. The ability of market parties to hoard transmission capacity is thus reduced as well.

Secondly, market coupling has proven to be an effective tool for "exporting" liquidity to less developed markets, subject to a limited degree of congestion. In the European power markets, market coupling was for instance instrumental in creating a functioning market environment in Denmark or Belgium, i.e. two markets that had remained largely illiquid on their own before. Although both countries continued to face congestion with more liquid markets in neighboring countries after the introduction of market coupling, market coupling nevertheless ensured sufficient convergence with other, more liquid markets and hence improved the credibility and liquidity of the local market.

There has been one pilot project for introduction of market coupling in the European gas markets , conducted by GRTgaz and Powernext in France (see Textbox 1). The results of this particular experiment have been mixed and depend on the level of congestion between PEG Sud and PEG Nord. This may be attributed to the particular design of the market coupling scheme which effectively resulted in a descending auction at times of high congestion. Indeed, the design of this market coupling scheme differed from the way it is implemented in European electricity markets.

To date, there has been one application of market coupling in European gas markets. Since July 2011, GRTgaz has, together with Powernext, executed an experiment for day-ahead market coupling between the northern and southern market area in France based on continuous trading. To this end, GRTgaz has reserved transmission capacity in both directions between PEG Nord and PEG Sud. GRTgaz offers this transmission capacity in case of diverging prices between the two PEG's. Results from this experiment have been mixed, depending on the situation (congestion or no congestion). In general, in case of no congestion, the market coupling experiment led to a reduction in the average spread between PEG Nord and Sud and to an increase in liquidity. However, at times of high congestion, spreads between PEG Nord and Sud increased and interconnection capacities were sold by a descending auction mechanism.

Textbox 1: Application of Market Coupling in France

Overall though, the extent to which market coupling can be introduced in existing gas markets depends on the specific situation. Several issues need to be considered before market coupling can be introduced in gas markets:

1. Compatibility with flexible re-nomination rights in the gas market.
2. Lack of consistency between the timeframes for capacity definition, trading, nominations and balancing in the gas market.
3. Timing of market coupling vs. use of continuous trading in the gas market.

Arguably one of the most critical issues for the introduction of market coupling is the use of flexible re-nomination rights in gas markets. In comparison, power markets generally lack short-term re-nomination rights. For example, in continental Europe, cross-border exchanges for electricity are subject to a firm early nomination deadline on the day-ahead (usually $\leq$ 9 h on D-1). This means that there is no additional flexibility for holders of long-term contracts after D-1 nomination. In fact, re-nominations in the electricity sector are limited to "new capacity rights", based on capacities that remain unused after day-ahead market coupling. In electricity markets, the restriction of re-nomination rights was in line with the traditional scheduling of power plants, whereas intra-day trading was (re-) introduced at a later time only.

In contrast, in the European gas markets, network users have always enjoyed the flexibility provided of making re-nomination on a short-term basis. Network users holding capacity rights are thus able to react better to within day price variations, but at the expense of others who are unable to use such capacities (at least on a firm basis). Moreover, it is argued that flexible re-nomination rights allow network users to exert contractual congestion by withholding capacity from the day-ahead or within day market.

It is often argued that the use of OTC trading and continuous trading in gas markets is another barrier for market coupling. However, it should be noted that both features are equally valid for the European electricity markets where the volume of OTC transactions (concluded under continuous trading) typically exceeds the volumes of the auction-based spot markets multiple times. Nevertheless, it is true that it is much more difficult to design a functioning market coupling algorithm for continuously traded markets. Moreover, market coupling in continuously traded markets will generally require greater liquidity on both sides, thereby removing one of the key advantages of market coupling.

In their (draft) position paper for consultation on the feasibility of implicit allocation in the North West European gas markets[23], the NRAs of the GRI NW state a.o. the following pre-conditions for introducing implicit allocation:

1. Bundling of cross-border capacity, as the allocation mechanism does not distinguish different interconnection points,
2. Product Compatibility, to be able to trade comparable gas products on both sides of the border so no additional risks to cross-border trading occur.

In general, both pre-conditions are part of the larger issue concerning the harmonization of the conditions and timeframes of for instance capacity definitions, trading, nominations and balancing in the connected markets. Although this issue is not directly limited to the application of market coupling, it considering the scope for application of market coupling.

6.4 Trading Region

The concept of a "trading region" was introduced during the discussions around the Gas Target Model. The concept was introduced by Glachant (2011) in his vision on the Gas Target Model: the MECO-S Model[24]. The MECO-S Model rests on three pillars:

1. Structuring network access to the European gas grid in a way that enables functioning wholesale markets;
2. Fostering short- and mid-term price alignment between the functioning wholesale markets by tightly connecting the markets;
3. Enabling the establishment of secure supply patterns to the functioning wholesale markets.

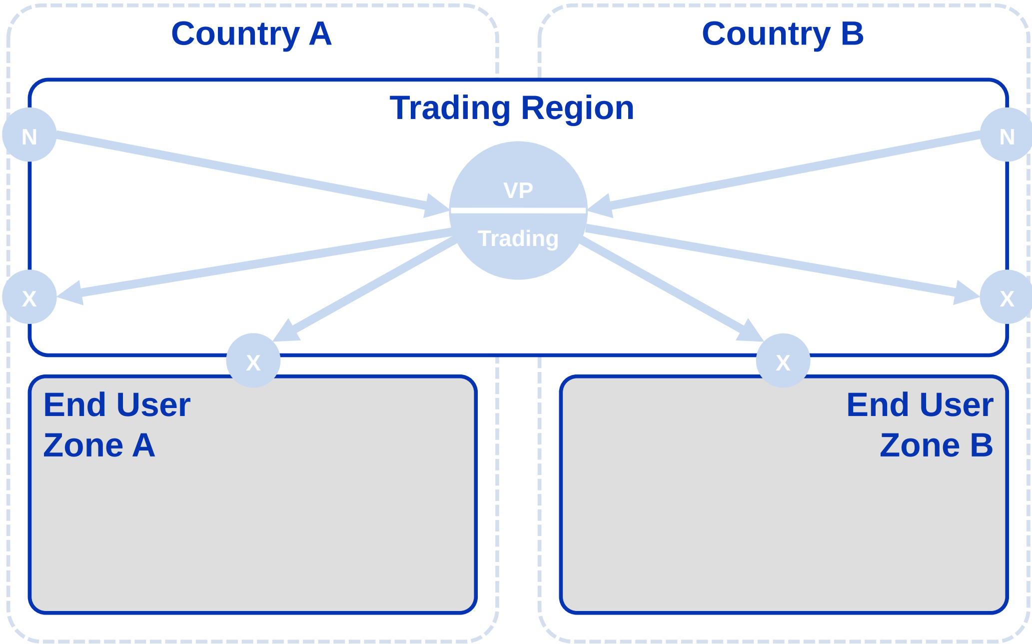
In this model, it is envisaged that Pillar 1 is implemented by "structuring Europe into markets that are sufficiently large and well connected to sources of gas so that the emergence of a competitive traded wholesale market is likely". In turn, these markets may either be established by full market area merger or by the creation of a trading region.

A trading region is defined as an entry-exit zone that comprises a number of transmission systems in a single zone which in turn is closely linked to one or several end user zones with their own balancing systems[25]. Hence, a trading region may be viewed as an additional integrating layer, consisting out of a single entry-exit system with a single virtual point, on top of existing "national end user zones", each with its own balancing system in place. The underlying end user zones are in turn accessed through virtual entry/exit points, one for each zone, and, as the name suggests, can be located in different countries. All final customers are assigned to the respective end user zones. Balancing occurs in the end user zones by local balancing entities and not at the trading region level as it is a fully nominated system (i.e. allocation is equal to nomination). The concept of a trading region is shown in Figure 17.

[23] Gas Regional Initiative North West, "Draft position paper for consultation – Exploring the feasibility of implicit allocation in the (North West) European gas market", 1 October 2012.

[24] Glachant, J.M., "A Vision for the EU Target Model: the MECO-S Model", EUI Working Paper RSCAS 2011/38.

[25] Glachant, J.M., "A Vision for the EU Target Model: the MECO-S Model", EUI Working Paper RSCAS 2011/38.



Source: Glachant (2011)[24]

Figure 17: Concept of a Trading Region

The trading region is said to have a number of advantages over a full market merger. First of all, the main advantage would be a reduction in the need for legal coordination between the involved countries as compared to a full market merger. Secondly, the trading region model does not necessitate a harmonisation of national balancing principles, as is the case in a full market merger, nor does it restrict such harmonisation. Also, the model is deemed to be suitable for Member States with smaller gas markets that may not have the consumption to facilitate their own functioning wholesale market. Furthermore, the trading region may be used as a first step towards a full market merger.

However, the creation of a trading region does not resolve all issues associated with a full market merger. For example, as the trading region consists of a single entry-exit system, the potential interconnection capacity required would be same as in the case of a full market merger. Furthermore, as internal border points will cease to exist, a loss of income for TSOs may occur. As a loss of income may negatively affect the TSOs some mechanisms may need to be put in place in order to compensate for this loss (e.g. inter-TSO compensation, acceptable tariff increases at other points). As a matter of fact, a common trading region thus requires the same preconditions to be met as a full market merger, except of the possible co-existence of separate balancing arrangements.

Another potential issue is related to imbalance settlement. In a system with pure daily balancing, i.e. without any within-day obligations, shippers might be able to offset their imbalances ex-post, i.e. by adjusting their nominations to (or from) the two end user or balancing zones during the day. Depending on the design of the balancing arrangements in the two balancing zones, this may lead to arbitrage between the balancing arrangements in the two zones.

Currently, there are no trading regions in the European gas markets. However, its implementation is being considered by several Member States. For example, one pilot project has been executed by Eustream, NET4GAS, CEGH and E-Control to develop a conceptual model and its basic principles for a CEE Trading Region (CEETR). The project is envisaged to enter into a second phase for the development of an implementation model after which a final decision regarding the actual implementation of the CEETR can be made. In addition, in its deliberation of 19 July 2012, the CRE indicates that it has set the objective to create a single market place in France. As an intermediate step, it has subsequently decided to merge the GRTgaz South VTP (PEG) and the TIGF VTP as of 1 April

2015. This common VTP may be implemented by means of the trading region model enabling the two independent balancing zones to be maintained[26].

Finally, it is worth noting that the German (and Austrian) electricity market has effectively functioned in a very similar way as a trading region for more than a decade. Although the German electricity market is split into four control areas, which are each operated by a separate TSO and have their own imbalance settlement, network users can freely exchange between electricity between the four control areas[27]

6.5 Conclusion

This section has provided an overview of alternatives to market area merger with the aim of integrating gas markets. The alternatives differ in various ways from each other, first and foremost, in their ability to integrate markets. For example, the trading region will guarantee an integrated gas market as, by definition, it has a single virtual point. Similarly, market coupling may also be able to integrate markets for most of the time. However, both concepts have not been applied in the European gas market or only as pilot projects and their actual ability to integrate markets has not been tested. Furthermore, although they would integrate the markets concerned, they do not necessarily assure integration with other surrounding market areas. For this, bundled products may be more suitable as these products can be applied to any cross-border point(s). A downside of bundled products is that they may only be facilitating in integrating markets instead of assuring market area integration.

Secondly, the alternatives require different levels of effort to be implemented. In general, the effort required for market mergers is expected to be the greatest as it requires cooperation on different topics (still depending on the level of harmonisation – e.g. tariff harmonisation) and potentially investments in infrastructure. Conversely, merging of markets, with the exception of cross-border mergers, has already been done in Europe before and as such the actual effort required could be reduced due to learning effects as compared to establishing trading regions or introducing market coupling, for which no precedents exists.

Also, the alternatives presented should not be considered as mutually exclusive. It would easily be possible to apply some of these alternatives in combination. For example, a trading region offering bundled capacities at its borders. Similarly, different alternatives may be considered in different parts of the European Union depending on the situation and the characteristics of the markets. For example, market coupling generally requires some form of gas trade on virtual points, whereas the creation of a trading region, with a single virtual point, may destroy liquidity when amalgamating areas with each its own virtual point. In contrast, when no virtual point is present in one of the areas, a trading region would be a far better solution than market coupling. Finally, some of these alternatives may be used in preparation towards further integration. For example, the pilot project initiated by GRTgaz was introduced as an interim step towards a full market area merger.

[26] CRE, "Deliberation of the French Energy Regulation Commission of 13 December 2012 deciding on the tariffs for the use of natural gas transmission networks", 13 December 2012.

[27] In contrast to the concept proposed by the MECO-S model, however, network users still have to make separate nominations for 4 "VPs", i.e. one for each control area.

7 SUMMARY AND CONCLUSIONS

This part B of the report provided an analysis on integrating gas markets. Firstly, we have examined the potential of integrating three different combinations of gas markets, i.e. Spain and Portugal, Ireland, Northern Ireland and Great Britain, and Hungary and Romania. For each of these combinations the costs and benefits associated with a market merger of the respective Member States were assessed. Secondly, an overview of non-investive alternatives to interconnection capacity was provided. Finally, this part provided an overview of alternatives means, as compared to a full market merger, of integrating gas markets.

For each of the three different combinations of gas markets a cost-benefit analysis was executed. The cost-benefit analyses focused on the quantitative aspects of a market merger, both from the costs involved with merging two markets as well as the expected benefits. Generally, the costs involved may be regarded as more straightforward and easier to quantify. After all, the major share of costs can be expected to stem from investments in additional gas transmission capacity as required to support a larger entry-exit system that is created by the merger of two market areas. This in turn requires sound network planning and is generally well understood by most transmission system operators and engineering companies.

Although well understood, one aspect of this process, which is directly linked to the principle of an entry-exit system, may deserve particular attention. By definition, an entry-exit system abstracts from contractual paths in the network and thus from the underlying physical reality. As such, firm capacities on each entry and exit point do not solely result from the technical characteristics of the network, but are dependent on the assumptions taken or scenarios defined as well. Although a task of the TSO, which bears responsibility for a reliable operation of the network to assure security of deliverability, it is the network users that determine the actual flows and that are dependent on the outcome of this process. Therefore, a clear and transparent process should be at the basis of these definitions. In our approach we have assumed that existing firm capacities should not be reduced after the market area merger.

Besides the costs involved, the estimation of benefits that may be reasonably expected from a market area merger may be regarded more challenging. In our analysis, we have adopted two different approaches. Both approaches are based on general economic theory and require modeling efforts. Inherent to any modeling effort is the choice of the modeling paradigm. The modeling paradigm may be explained as the basic underlying assumption on which the model is based and how reality is reflected in the model[28]. No matter what the actual outcome is, the results should always be carefully interpreted as the choice of the modeling paradigm may lead to an over or underestimation of the potential benefits. Furthermore, the choice of the modeling paradigm can be more suited for one combination of markets than another. In our analysis, the first approach assumed a perfectly competitive market[29], which may be (or not) a valid representation of the markets modeled.

We have estimated the costs and benefits involved with a full market merger; i.e. the creation of a single entry-exit system. However, as explained in Section 6, there are alternative means to enable to integration of gas markets. In our cost benefit analysis we did not explicitly distinguish between the different alternatives. Ideally in the decision of merging two or more markets, these alternative options should be taken into account as well, i.e. one alternative may result in similar benefits at lower costs.

[28] Of course, the results of any model are also heavily dependent on the input (data) fed into the model. However, uncertainties in input (data) may often be understood and evaluated by applying sensitivity analysis or other more advanced (probabilistic) approaches.

[29] The second approach assumed an oligopolistic competition. Another assumption frequently adopted is the notion of perfect foresight versus stochastic approaches.

Of course, this option should be preferred from a quantitative point of view. Nevertheless, it remains to be seen whether a clear quantification of benefits is possible for each of the alternative options and the uncertainty and abstraction involved. For example, under the assumption of perfect competition, modeling a secondary capacity market may result into similar benefits as a full market area merger.

Another aspect that has to be taken into account is the scope under consideration and the distribution of welfare among those entities included within this scope. Scope may be related to the geographic area as well as the parties considered. Regarding a CBA for Member States of the European Union, the geographic scope may be easily defined by the boundaries of the EU. Also, there may be a redistribution of welfare among different parties, e.g. a change in the balance between consumer and producer surplus, without a change in total welfare. In our analysis, we focused on the respective Member States and mainly assessed the benefits from a consumer's perspective.

With respect to the three combinations the following conclusions were drawn:

- **Spain and Portugal**

  The analysis indicates moderate net benefits of merging the Portuguese and Spanish gas markets. Benefits may increase if the Spanish and Portuguese TSOs managed to avoid additional investments whilst enabling the market area merger and continuing to ensure reliable gas supplies to end consumers. The costs associated with alternative measures are generally expected to be lower than investing in new infrastructure, but will depend on the measure chosen and have not been quantified in this study.

- **Republic of Ireland, Northern Ireland and Great Britain**

  A merger of the gas markets of Great Britain, the Republic of Ireland and Northern Ireland may lead to significant costs in the short to mid-term, which are mainly related to the possibility of physical reverse flows from the Republic of Ireland and Northern Ireland to Great Britain. The gas market of Great Britain is generally regarded as the most liquid in Europe with a low market concentration. Hence, any benefits from an increase in competition are expected to primarily occur in the Irish gas market instead of in the GB market. However, as most of Ireland's gas is sourced on the NBP already, it seems uncertain whether a merger of these markets will lead to any tangible benefits. Instead, it may be more beneficial to consider other, less rigorous alternatives for promoting integration of the individual markets.

- **Hungary and Romania**

  The assessment shows that the current interconnection capacity is rather limited in relation to the size of the Romanian and Hungarian gas markets. Consequently, large investments would be required to enable a full market merger and, at the same time, offer the same level of reliability of supply to end consumers. Several ways to reduce the required interconnection capacity have been identified, but it turned out that these options would not suffice to completely eliminate it.

  The potential benefits that may arise from a market merger between Hungary and Romania could not be quantified at this stage. This mainly has to do with the current situation of the Romanian gas market and its forthcoming deregulation; this process makes it very difficult to estimate any potential benefits. A merger of both markets may thus be regarded as premature at this point, as it is unclear how the Romanian market will evolve during the next few years as a result of liberalisation and the introduction of the European network codes.

These results show that the net benefits of merging two or more market areas may be small or even negative. In contrast, experience in for example France and Germany has shown that market integration has been instrumental for increasing liquidity, and for truly opening up the local gas market for competition. In combination, these observations indicate that market integration should be pursued, but that the means to do so should be carefully chosen. Moreover, it may not always be the best choice to aim for full integration of neighbouring market areas, whilst it may be beneficial to consider alternative means to a full market merger.

Appendix A - Cost-Benefit Analysis – Main Assumptions and Results

The main assumptions and results of the cost benefit analysis are documented in a slide set which is attached as a separate document to this report.