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Quo vadis EU gas market regulatory framework – Study on a Gas Market Design for Europe

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TABLE OF CONTENTS

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ABSTRACT

The Quo vadis study identifies the potential inefficiencies of the internal EU gas market regulatory framework after the full implementation of the Third Energy Package, and discusses the additional regulatory measures which could lead to the improvement of EU welfare. The proposed regulatory measures are assessed based on both qualitative and quantitative criteria.

The key potential market inefficiencies identified and analysed in this study comprise upstream market concentration, long-term capacity bookings and associated network access problems, the current level and staructure of cross-border tariffs and institutional constraints to market development and integration.

Consequently, the alternative regulatory scenarios developed aim to present a major change, each of them in at least one regulatory aspect, with the goal of promoting significant EU welfare gain, while allowing for a feasible implementation. These scenarios are analysed and modelled against a Reference Scenario.

The study concludes that based on modelling results moderate welfare gain can be achieved by selecting the appropriate future regulatory design. The proposed measures proved to be significantly sensitive to selected gas market expectations, such as supply volume or new infrastructure commissioning where they lead to higher welfare increase.

Authors's statement

Discussion papers of the Quo vadis project tenderers and the subsequent stakeholders' feedback collected throughout the project phase highlighted the differences in perspective on the functioning of the internal gas market (IGM) and hence different perceptions of where the problems are and how they should be solved. As the EU gas-related legislation has not been implemented fully and consistently across the EU and some network code provisions, as well as the newly-adopted security of supply regulation are still awaiting implementation, there is significant room for interpretation with regard to the impact potential of complete implementation of all legislation by 2020 on the functioning of the IGM. This notwithstanding, we have outlined and modelled the alternative regulatory scenarios under various sensitivity conditions, which principally build on regulatory changes to the assumed regulatory framework, to assess as clearly as possible the impact each may have on economic welfare, compared to the Reference Scenario.

EXECUTIVE SUMMARY

The Quo vadis study evaluates the functioning of the European Union's internal gas market under the Third Package rules from a forward-looking perspective. On that basis it sets out and assesses alternative measures proposed to generate long-term benefits to consumers and EU market players. The study further concludes that the future performance and the international competitiveness of the EU gas market will not only depend on a successfully completed market integration process, but even more on the EU's ability to manage its high exposure to extra-EU suppliers.

Background

ACER's gas target model is at present the most comprehensive concept on how the EU gas market could develop from Third Package compatible member state level gas trading zones via a stage of voluntary, bottom-up integration process (e.g., regional market mergers) to a fully integrated EU gas market. However, the voluntary market merger process is proceeding very slowly. No provision in the Third Package guarantees this process to be ever completed.

A sharp contrast to the ACER concept is the vision of a centrally organized single EU gas market, operated by a single European TSO to ensure maximum market and operational efficiency. However, this vision of a centrally planned and managed market is not compatible with the political fundamentals of the European Union.

Current market functioning

By early 2018, there is a general stakeholder consensus that the EU internal gas market (IGM) has improved its functioning in recent years. Apart from some Central and South-East European (CSEE) Member States, market liquidity has been improving, competition at the wholesale level is intense, wholesale prices are moderate and converging across the EU. Market pricing is gradually replacing oil product-linked pricing. Given a moderate future gas demand outlook, the level of investment is generally sufficient in the sector.

However, our in-depth analysis of 2015-16 wholesale price differences within the EU shows that the European gas market is not yet a fully integrated single market. While the wholesale gas markets of Denmark, Belgium, the United Kingdom, the Netherlands and Germany create a single price zone, the presence of different trade barriers (cross border tariffs; lack of interconnectors; physical and contractual congestion) as well as differences in local market structure and exposure to upstream suppliers can explain remaining wholesale price differences.

Unless any regulatory or significant tariff change comes, we expect market segmentation to increase within the EU in the future. The current situation of overbooked transmission capacity by long-term contracts (LTC) will change between 2020 and 2030. The transformation of the capacity market from long to short term may cause a more profound price segmentation of the IGM with greater location spreads compared to today, which will fully reflect short-term transmission tariffs and physical flow direction. This may happen because new capacity bookings after expired LTCs will come at an actual, instead of a sunk cost to traders.

High upstream market concentration

The price premium that EU wholesale customers have been paying over US prices in the last decade is largely related to the concentrated nature of the EU gas upstream sector, including extra-EU gas suppliers. The debate about the efficiency of the IGM and its potential for further improvement has to be evaluated in this broader context.

Additionally, long-term capacity bookings and physical delivery to the target country by extra-EU producers create inefficiencies in the redistribution of the contracted gas volumes according to short term supply – demand conditions within Europe.

The Network Code on Capacity Allocation Mechanisms (CAM NC) in its present form is unable to effectively address the risk of market foreclosure by long-term capacity bookings. The first large scale application of CAM NC logic[1] on capacity auction with new capacities provided a stark example of potential market foreclosure by long-term capacity bookings by an extra-EU producer.

Cross-border tariffs as trade barriers

National entry–exit systems charging full cost for gas transportation plus - potentially - auction premium at intra-EU IPs, including applying distortive IP tariffs at certain borders, enhance market segmentation rather than market integration. The present structure of cross-border gas transmission tariff system and the related tariff 'pancaking' (accumulation of tariffs to be paid by traders when shipping gas through several borders) have an effect of trade barriers within the EU. Pancaking hits new entrants to cross-border trading, limits the use of alternative gas transportation routes so some routes may not be efficiently used and creates a barrier to develop more efficient cross-border balancing. We expect these problems to become more visible as LTC capacity bookings start expiring from 2019.

Neither the market merger process nor the Tariffs Network Code (TAR NC) implementation process seem sufficient in addressing the pancaking issue. The progress of voluntary market mergers is politically complex, slow and expensive. The most likely outcome of TAR NC implementation will be the stabilization of present IP tariff levels with a parallel cut back of high outlier tariffs in the coming years.

Proposed alternative regulatory scenarios and their evaluation

If upstream market concentration remains at the current level, generally speaking, putting competitive pressure on dominant pipeline suppliers remains the key regulatory option to mitigate its negative consequences. LNG and inter-fuel competition by renewable resources have such a potential.

The study provides a combined qualitative and quantitative assessment for the following alternative regulatory scenarios.

- **Tariff Reform Scenarios with uniform tariff increase and with harmonized EU entry tariffs.** In this case, within-EU IP tariffs are set to zero so that the revenue neutrality of this change for each TSO is ensured by a simultaneous tariff increases at remaining entry and /or exit points. The proposed institution to ensure revenue neutrality is a newly founded TSO Compensation Fund (TCF).

  The Tariff Reform Scenario makes cross-border gas trading cheaper. This will encourage increased imports by formerly more expensive countries from the cheaper regions up to full price equalization or infrastructure constraints. Wholesale prices fall in importing countries and rise in exporting ones.

- **Market Merger Scenarios**, where cross-border tariffs within the merged zones are eliminated and the lost TSO revenues are collected from additional tariffs on the IPs on the borders of the zones. As in the Tariff Reform Scenario a TCF covering the merged zones would need to be set up.

[1] The CAM incremental capacity rules are applicable officially only as of 16 March 2017 with possibility of an additional transitional arrangement.

- **The Combined Capacity-Commodity Release Scenario** proposes a simultaneous increase up to 50% in the share of short-term transmission capacities for both existing and new infrastructure, and an obligation for gas producers/importers to sell at least 50% of their gas at the nearest Virtual Trading Point (VTP) to their entry into the transmission grid on EU territory. The objectives of the scenario are to boost network use efficiency EU-wide and improve market liquidity in regions with low market liquidity and high market concentration.
- **The Extra-EU upstream – EU Downstream Strategic Partnership Concept -** the EU and Russia enter into a mutually beneficial agreement to integrate their gas markets in a fundamental way.

The quantitative welfare analyses of the regulatory scenarios were carried out by the European Gas Market Model (EGMM). This entailed the assessment of the wholesale price and welfare changes implied by the implementation of the regulatory scenarios on 2020 reference market conditions and on five sensitivity market cases: (1) high demand, (2) LNG glut, (3) high oil price – LNG short and (4-5) two versions of Nord Stream 2 project implementation.

Due to the nature of the EGMM (no short-term trading represented, perfect competition assumed), the modelling results provide very conservative economic benefit (total welfare change) estimates for the investigated regulatory scenarios. The EGMM cannot simulate daily bidding and we thus have no reliable measure of market liquidity. While we assume that some of the regulatory scenarios, notably the Tariff Reform Scenario will ease cross-border balancing and is likely to improve market liquidity, the EGMM could not capture and quantify these positive impacts. The model's fundamental comparative static nature also puts a limit on simulating the outcomes of the investment incentives inherent for the regulatory scenarios.

Based on the combined qualitative and quantitative regulatory scenario analyses we draw the following conclusions.

(1) The Tariff Reform Scenario recommends restructuring the point of collection of EUR 2-3 billion TSO revenues to further promote trade and market integration on the approximately EUR 100 billion IGM. To go ahead with the Tariff Reform Scenario would be a smart move to enhance price convergence and insure against the risk of future gas market segmentation in the EU. Under the present and forecasted 2020 reference gas market conditions the implementation of a carefully designed tariff reform scenario could support further welfare improving gas market integration within the EU even in the current low demand and low-price market environment. This is reflected by the almost complete wholesale price convergence these scenarios imply.

The typical pattern of Tariff Reform Scenario welfare impacts under expected 2020 reference market conditions is that they rather redistribute than increase welfare through increased cross-border trading. However, the implementation of the Tariff Reform Scenario turns highly beneficial when implemented under more turbulent sensitivity scenarios, which bring increased price divergence for the IGM. It performs especially well by producing more than EUR 5 billion annual consumer welfare increase when implemented in a high oil price and LNG short environment and when Nord Stream 2 is built, and Russia supplies only remaining LTC quantities (but no spot volumes) through Ukraine.

Further, the Tariff Reform Scenario could help the voluntary market merger process by removing one of the critical conflict issues from merger discussions: IP point and tariff removal and related inter-TSO compensation problems, since the TSO Compensation Fund would have already solved them.

The Tariff Reform Scenario could boost the competitive pressure LNG puts on pipeline gas suppliers in regions with no direct access to LNG. Moreover, a tariff reform could bring about additional welfare benefits, like increased short-term market liquidity and more flexibility in cross-border balancing, that the EGMM cannot capture.

The performance of the Tariff Reform Scenario is sensitive to design issues. Its versions with additional tariffs on LNG entry points tend to immediately increase wholesale prices across the EU and as such are destructive for consumer welfare. Another complexity of the proposed Tariff Reform Scenario is that it is to be complemented with a TSO Compensation Fund.

(2) The investigated market merger cases brought moderate EU welfare improvements in those cases when wholesale price differences were still present before the merger. The merger of the Spanish and Portuguese markets on the 2020 reference produced negligible price and welfare impacts because we expect the already moderate (below 0.5 EUR/MWh) 2016 wholesale price difference levelling off by 2020 due to increasing demand and LNG costs.

There are two major aspects of a merger scenario that can undermine the social benefits of the case: the additional cost of expanding the infrastructure for the merged zone (if needed) and the potential price increase in the countries neighbouring the merged zone due to the additional tariffs put on the zone's outside entry/exit points. We did not quantify the infrastructure related costs of the investigated merger cases, but we assume that it would be significant in the North-West and Baltic merger cases.

We found the second impact (increased prices in neighbouring countries) relevant in the North-West (DE-NL-BE-LU-CZ) merger case. This is a warning that while a bottom-up approach of smaller market mergers might be politically easier and thus the more feasible way towards gas market zones integration, this segmented process could lead to a set of market zones separated by high tariff barriers around the EU – a rather negative outcome.

(3) The Combined Capacity-Commodity Release Scenario improves EU welfare and is a robust and focused measure. It improves EU consumer welfare by an annual EUR 1.5-3 billion across the different sensitivity scenarios and results mostly in a positive total welfare outcomes. The sources of welfare improvements are increasing product market competition in less liquid CSEE countries (commodity release) and improved efficiency in using the EU gas transmission infrastructure (capacity release).

There are two additional advantages of this scenario. It reduces prices and improves the welfare in relatively high price countries without implying a parallel price increase in low price countries. In addition, it requires only the modification of existing legislation (CAM NC) and the application of existing experiences with past gas release programs but no new institution (like a TCF) or major new regulation is a precondition for its application.

Therefore, we conclude that the implementation of this scenario is a no-regret policy and recommend to consider it for the implementation.

(4) An extra-EU upstream and EU downstream Strategic Partnership might have the potential to significantly decrease EU gas wholesale prices. This cooperative concept could clearly reshape the upstream conditions for the EU IGM and, depending on the result of the related benefits sharing, it could provide significant welfare gains for EU stakeholders, especially customers.

However, this concept is highly hypothetic and intends only to initiate further thinking and research into potential cooperative solutions for the EU gas markets' most important problem that is high import dependence and simultaneous high market concentration.

The most important sensitivity scenario related observations are as follows.

(1) Gas market related total welfare is highly sensitive to gas demand and LNG supply shocks in the EU. While higher than reference demand increase could boost gas consumption related EU welfare due to abundant and flexible supply conditions, EU welfare is highly sensitive to LNG supply conditions.

(2) The most efficient measure to put competitive pressure on EU pipeline gas suppliers and improve EU welfare is to provide seamless access for LNG to the EU IGM. Aside from the Strategic Partnership concept, it was only in the LNG glut sensitivity scenario where we could simulate remarkable wholesale gas price decreases. An LNG glut in combination with a Combined Capacity-Commodity Release Scenario could reduce EU gas wholesale prices the most. Tariff Reform Scenario versions that increase LNG entry tariffs to the EU transmission grid are highly destructive for EU welfare.

(3) Once it is built, the impact of Nord Stream 2 on EU consumers' welfare depends on the unilateral decision of Russia on how to use (or not to use) the Ukrainian transit pipeline system. From the realistic regulatory scenarios, the tariff reform seems to be the most effective remedy to relieve the sharp price divergence that Nord Stream 2 is expected to create between North-West, Central and South East Europe.

Recommendations

The analyses presented in this study support the following policy recommendations.

- Amend paragraphs 6 and 7 of Article 8 of Regulation 2017/459 to increase the share of existing technical capacity that TSOs are obliged to set aside and offer for auctioning for yearly or shorter durations to 50% or more. The same approach of increasing the share of yearly or shorter durations from 10% to 50% should also be considered for incremental capacity within the EU to prevent future market foreclosure.
- Consider the full implementation of the Combined Capacity-Commodity Release Scenario. This would entail the amendment of Regulation 2017/459 as indicated in the former recommendation and the implementation of gas release programs for existing and future LTCs in the EU countries of entry for LTC commodity.
- Consider the implementation of the Tariff Reform Scenario after further refining the design and implementation conditions of it as presented in the study. Designs with add-on tariffs differentiated by EU entry, EU exit and domestic exit points as well as TCF implementation issues should further be considered.
- Include the concept of a potential Strategic Partnership – and the corresponding liberalization of the Russian gas sector – on the agenda of future EU-Russia energy dialogue and negotiation process on Nord Stream 2 or DG Competition cases with the objective to promote a competitive EU gas upstream sector.

RÉSUMÉ

L'étude Quo vadis évalue le fonctionnement du marché intérieur du gaz de l'Union européenne dans le cadre des règles du Troisième Paquet Energie dans une perspective d´avenir. Sur cette base, elle définit et évalue des mesures alternatives proposées pour créer des bénéfices à long terme pour les consommateurs et les acteurs du marché de l'UE. L'étude permet en outre de conclure que les performances futures et la compétitivité internationale du marché du gaz de l'UE dépendront non seulement d'un processus d'intégration de marché achevé avec succès, mais encore de la capacité de l'UE à gérer sa forte exposition aux fournisseurs situés en dehors de l´UE.

Contexte

Le modèle de gaz d'ACER est actuellement le concept le plus exhaustif sur la manière dont le marché de gaz de l´UE pourrait se développer à partir des zones de commerce de gaz compatibles avec le Troisième Paquet Energie, via une phase d'intégration volontaire ascendante (par ex. marché du gaz de l'UE) à un marché du gaz européen pleinement intégré. Cependant, le processus de fusion des marchés à caractère volontaire avance très lentement. Aucune disposition du Troisième Paquet Energie ne garantit que ce processus soit un jour achevé.

La vision d'un marché unique du gaz au sein de l'UE, exploité par un seul GRT européen, pour assurer un maximum d'efficacité commerciale et opérationnelle, contraste fortement avec le concept ACER. Cependant, cette vision d'un marché centralement planifié et contrôlé n'est pas compatible avec les fondements politiques de l'Union européenne.

Fonctionnement actuel du marché

Au début de l'année 2018, les parties prenantes s'accordent à penser que le marché intérieur du gaz (MIG) de l'UE a amélioré son fonctionnement ces dernières années. Outre certains États membres d'Europe centrale et d'Europe du Sud-Est, la liquidité du marché s'est améliorée, la concurrence au niveau de la vente en gros est intense, les prix de gros sont modérés et convergent dans l'UE. Les prix du marché remplacent progressivement les prix liés aux produits pétroliers. Compte tenu des perspectives modérées de la future demande de gaz, le niveau d'investissement est généralement suffisant dans le secteur.

Cependant, notre analyse approfondie des différences de prix de gros en 2015 et en 2016 au sein de l'UE montre que le marché européen du gaz n'est pas encore un marché unique totalement intégré. Alors que les marchés de gros au Danemark, en Belgique, au Royaume-Uni, aux Pays-Bas et en Allemagne créent une seule zone de prix, la présence de différentes barrières commerciales (tarifs transfrontaliers, absence d'interconnexions, congestion physique et contractuelle) ainsi que la structure du marché local et l'exposition aux fournisseurs en amont peuvent expliquer les différences de prix de gros restantes.

À moins d'un changement tarifaire réglementaire ou significatif, nous prévoyons que la segmentation du marché augmentera à l'avenir dans l'UE. La situation actuelle des capacités de transport surbookées par les contrats à long terme (CLT) changera entre 2020 et 2030. La transformation du marché des capacités à court et long terme pourrait entraîner une segmentation plus profonde des prix du marché intérieur du gaz avec des écarts de localisation plus importants qu'aujourd'hui, ce qui reflétera entièrement les tarifs de transport à court terme et la direction du flux physique. Cela peut se produire parce que les nouvelles réservations de capacité après les CLT expirés se feront à un prix réel, au lieu d'un coût irrécupérable pour les traders.

Concentration du marché élevée en amont

La prime que les clients de gros de l'UE ont payée sur les prix américains au cours de la dernière décennie est largement liée à la nature concentrée du secteur gazier en amont de l'UE, y compris les fournisseurs de gaz en dehors de l´UE. Le débat sur l'efficacité du MIG et ses possibilités d´améliorations doit être évalué dans ce contexte plus large.

De plus, les réservations de capacité à long terme et la livraison physique dans le pays cible par des producteurs en dehors de l´UE créent des inefficacités dans la redistribution des volumes de gaz contractés en fonction des conditions d'offre et de demande à court terme en Europe.

Le code de réseau sur les « Mécanismes d'Allocation des Capacités » ou CAM NC (Network Code on Capacity Allocation Mechanisms) sous sa forme actuelle est incapable de traiter efficacement le risque de verrouillage du marché par des réservations de capacité à long terme. La première application à grande échelle de la logique de CAM NC[2] sur la capacité de vente aux enchères avec de nouvelles capacités a fourni un exemple frappant de verrouillage potentiel du marché par les réservations de capacité à long terme d'un producteur en dehors de l´UE.

Les tarifs transfrontaliers comme barrières commerciales

Les systèmes nationaux d'entrée-sortie facturant le coût total du transport de gaz ainsi que, potentiellement, les primes aux enchères sur la PI (propriété intellectuelle) à l´intérieur de l´UE, y compris l'application de droits de propriété intellectuelle à certaines frontières, renforcent la segmentation du marché plutôt que son intégration. La structure actuelle du système de tarification transfrontalier du transport de gaz et l´accumulation des tarifs à payer par les commerçants lors de l'acheminement du gaz à travers plusieurs frontières («pancaking») ont pour effet de créer des barrières commerciales au sein de l'UE. Le pancaking frappe les nouveaux entrants au commerce transfrontalier, limite l'utilisation de voies alternatives de transport du gaz, au point où certaines routes pourraient ne pas être utilisées efficacement, et crée une barrière pour développer un équilibrage transfrontalier plus efficace. Nous prévoyons que ces problèmes deviendront plus visibles à mesure que les réservations de capacité des CLT expirent à partir de 2019.

Ni le processus de fusion du marché ni le processus de mise en œuvre du code de tarification du réseau ou TAR NC (The Tariffs Network Code) ne semblent suffisants pour résoudre le problème du pancaking. La progression des fusions volontaires sur les marchés est politiquement complexe, lente et coûteuse. Le résultat le plus probable de la mise en œuvre du code de tarification du réseau sera la stabilisation des niveaux actuels des droits de PI avec une réduction parallèle des tarifs élevés dans les années à venir.

Proposition de scénarios réglementaires alternatifs et leur évaluation

Si la concentration du marché en amont demeure au niveau actuel, la pression concurrentielle exercée sur les principaux fournisseurs de pipelines demeure la principale option réglementaire pour atténuer ses conséquences négatives. Le GNL et la concurrence entre combustibles issus des ressources renouvelables ont ce potentiel.

L'étude fournit une évaluation combinée qualitative et quantitative pour les scénarios réglementaires alternatifs suivants.

[2] Les règles relatives à la capacité incrémentielle de la CAM ne sont applicables officiellement qu'à compter du 16 mars 2017, avec possibilité d'un arrangement transitoire supplémentaire.

- **Scénarios de Réforme Tarifaire avec une augmentation tarifaire uniforme et avec des tarifs d'entrée harmonisés dans l'UE**. Dans ce cas, les tarifs de PI de l´UE sont mis à zéro, de sorte que la neutralité des revenus de ce changement pour chaque GRT est assurée par une augmentation tarifaire simultanée aux points d'entrée et / ou de sortie restants. L'institution proposée pour assurer la neutralité des revenus est un fonds de compensation GRT nouvellement créé.

  Le Scénario de Réforme Tarifaire rend le commerce transfrontalier de gaz moins cher. Cela encouragera l'augmentation des importations par les pays autrefois plus chers depuis des régions moins chères jusqu'à l'équilibre total des prix ou aux contraintes d'infrastructure. Les prix de gros chutent dans les pays importateurs et augmentent dans les pays exportateurs.

- **Scénarios de fusion du marché,** où les tarifs transfrontaliers dans les zones qui ont fusionné sont éliminés et les pertes de revenus des GRT sont collectées à partir des tarifs additionnels des PI sur les frontières des zones. Comme dans le scénario de Réforme tarifaire, un fonds de compensation de GRT couvrant les zones fusionnées devrait être mis en place.

- **Le scénario combiné de la mise à disposition (release) des capacités et du gaz** propose une augmentation simultanée de 50% de la capacité de transport à court terme pour les infrastructures existantes et nouvelles et une obligation pour les producteurs / importateurs de gaz de vendre au moins 50% de leur gaz au Point de Trading Virtuel (PTV) le plus proche de leur entrée dans le réseau de transmission sur le territoire de l'UE. Les objectifs du scénario sont d'accroître l'efficacité de l'utilisation du réseau dans l'ensemble de l'UE et d'améliorer la liquidité du marché dans les régions où elle est faible et où la concentration du marché est élevée.

- **Le concept de partenariat stratégique entre la production en dehors de l´UE et la consommation dans l´UE** - l'UE et la Russie concluent un accord mutuellement bénéfique pour intégrer leurs marchés du gaz de manière fondamentale.

Les analyses quantitatives du bien-être des scénarios réglementaires ont été réalisées par le modèle européen du marché du gaz (European Gas Market Model). Cela impliquait l'évaluation des changements de prix de gros et en terme de bien-être induits par la mise en œuvre des scénarios réglementaires sur les conditions de marché de 2020 et sur cinq cas de sensibilité: (1) forte demande, (2) surabondance de GNL, (3) prix élevé du pétrole - GNL court et (4-5) deux versions de la mise en œuvre du projet Nord Stream 2.

En raison de la nature du modèle européen du marché de gaz (pas de négociation à court terme, l´hypothèse d´une concurrence parfaite), les résultats de la modélisation fournissent des estimations économiques très conservatrices (changement total de bien-être) pour les scénarios réglementaires étudiés. Le modèle européen du marché de gaz ne peut pas simuler les appels d´offres journaliers et nous n'avons donc aucune mesure fiable de la liquidité du marché. Même si nous supposons que certains des scénarios réglementaires, notamment le scénario de réforme tarifaire, faciliteront l'équilibrage transfrontalier et amélioreront probablement la liquidité du marché, le modèle européen du marché de gaz n'a pas pu saisir et quantifier ces impacts positifs. La nature statique comparative fondamentale du modèle limite également la simulation des résultats des incitations à l'investissement inhérentes aux scénarios réglementaires.

Basé sur les analyses de scénarios réglementaires qualitatifs et quantitatifs combinés, nous pouvons alors en tirer les conclusions suivantes.

(1) Le scénario de réforme tarifaire recommande de restructurer le point de collecte de 2 à 3 milliards d'euros de recettes de GRT afin de promouvoir davantage l'intégration du commerce et IGM d´environ 100 milliards d'euros. Poursuivre le scénario de la réforme tarifaire serait une initiative judicieuse pour améliorer la convergence des prix et se garantir contre le risque de segmentation future du marché du gaz dans l'UE. Dans les

conditions actuelles et prévues du marché du gaz de référence de 2020, la mise en œuvre d'un scénario de réforme tarifaire soigneusement conçu pourrait favoriser une meilleure intégration du marché du gaz dans l'UE, même dans l'environnement actuel de faible demande et de prix bas. Cela se reflète dans la convergence presque totale des prix de gros que ces scénarios impliquent.

La tendance typique des effets sur le bien-être du scénario de réforme tarifaire dans les conditions de marché de référence prévues pour 2020 est qu'ils redistribuent plutôt qu'augmentent le bien-être en augmentant les échanges transfrontaliers. Cependant, la réalisation du scénario de réforme tarifaire s'avère très bénéfique lorsqu'elle est mise en œuvre dans des scénarios de sensibilité plus volatiles, ce qui entraîne une divergence de prix accrue pour le MIG. Il est particulièrement performant en produisant plus de 5 milliards d'euros de bien-être annuel lorsqu'il est mis en œuvre dans les conditions de prix élevé de pétrole et de déficience de GNL et lorsque Nord Stream 2 est construit, et que la Russie ne fournit que des quantités restantes de contrats à long terme (mais pas de volumes achetés au comptant sur le marché ukrainien).

En outre, le scénario de réforme tarifaire pourrait faciliter le processus de fusion volontaire en supprimant l'une des sources majeures de conflit de la discussion sur la fusion: suppression des points de PI et des tarifs et problèmes de compensation inter-GRT connexes, puisque le fonds de compensation GRT les aurait déjà résolus.

Le scénario de réforme tarifaire pourrait accroître la pression concurrentielle que le GNL exerce sur les fournisseurs de gazoduc dans les régions n'ayant pas d'accès direct au GNL. De plus, une réforme tarifaire pourrait apporter des avantages sociaux supplémentaires, comme une liquidité accrue à court terme sur le marché et une plus grande flexibilité dans l'équilibrage transfrontalier, que le modèle de marché du gaz européen ne peut pas saisir.

La performance du scénario de réforme tarifaire est sensible aux problèmes de conception. Ses versions avec des tarifs supplémentaires sur les points d'entrée du GNL tendent à augmenter immédiatement les prix de gros à travers l'UE et à ce titre sont destructrices pour le bien-être des consommateurs. Une autre difficulté du scénario de réforme tarifaire proposé est qu'il doit être complété par un fonds de compensation GRT.

(2) Les cas de concentration de marché examinés ont apporté des améliorations modérées du bien-être de l'UE dans les cas où les différences de prix de gros étaient toujours présentes avant la fusion. La fusion des marchés espagnols et portugais sur la référence 2020 a eu un impact négligeable sur les prix et le bien-être car il est à espérer que la différence des prix de gros de l´année 2016 déjà modérée (inférieure à 0,5 EUR / MWh) devienne encore plus faible en raison de l'augmentation de la demande et des coûts du GNL.

Deux aspects majeurs d'un scénario de fusion peuvent compromettre les avantages sociaux de l'affaire: le coût additionnel de l'extension de l'infrastructure pour la zone fusionnée (si nécessaire) et l'augmentation potentielle des prix dans les pays voisins de la zone fusionnée en raison des tarifs additionnels qui sont mis sur les points d'entrée / sortie extérieurs de la zone. Nous n'avons pas quantifié les coûts liés à l'infrastructure des cas de fusion étudiés, mais nous supposons que cela serait important dans les cas de fusion du Nord-Ouest et de la Baltique.

Nous avons trouvé le deuxième impact (hausse des prix dans les pays voisins) pertinent dans le cas de fusion de Nord-Ouest (DE-NL-BE-LU-CZ). Ceci est un avertissement que quand bien même une approche ascendante des fusions de marché plus petites pourrait être politiquement plus facile et donc la voie la plus réalisable vers l'intégration des zones gazières, ce processus segmenté pourrait conduire à une série de zones de marché séparées par des barrières tarifaires élevées dans l´ensemble de l´UE - un résultat plutôt négatif.

(3) Le scénario combiné de la mise à disposition (release) des capacités et du gaz améliore le bien-être de l'UE et constitue une mesure robuste et ciblée. Il améliore le bien-être des consommateurs européens d'un montant annuel de 1,5 à 3 milliards d'euros à travers les différents scénarios de sensibilité et se traduit principalement par des résultats positifs totaux en matière de bien-être. Les sources d'amélioration du bien-être sont l'augmentation de la concurrence sur les marchés de produits dans les pays moins liquides d'Europe centrale et d'Europe du Sud-Est et la meilleure utilisation des infrastructures de transport de gaz de l'UE (libération de capacité).

Il y a deux avantages supplémentaires à ce scénario. Il réduit les prix et améliore le bien-être dans les pays à prix relativement élevés sans impliquer une augmentation parallèle des prix dans les pays à bas prix. En outre, il ne nécessite que la modification de la législation existante (CAM NC) et l'application des expériences existantes avec les anciens programmes de rejet de gaz, mais aucune nouvelle institution (comme un fonds de concentration de GRT) ou une nouvelle réglementation majeure n'est une condition préalable à son application.

Par conséquent, nous concluons que la mise en œuvre de ce scénario est une politique sans regret et recommandons de l´examiner pour la mise en œuvre.

(4) Un partenariat stratégique entre la production en dehors de l´UE et la consommation dans l´UE pourrait potentiellement réduire considérablement les prix de gros de l'UE. Ce concept coopératif pourrait clairement remodeler les conditions en amont du MIG de l'UE et, en fonction du résultat du partage des avantages, il pourrait apporter des avantages significatifs pour les parties prenantes de l'UE, en particulier les clients.

Cependant, ce concept est hautement hypothétique et vise seulement à initier une réflexion et une recherche plus poussées sur des solutions de coopération potentielles pour le problème le plus important des marchés gaziers de l'UE, à savoir la forte dépendance aux importations et la forte concentration simultanée du marché.

Les observations les plus importantes liées au scénario de sensibilité sont les suivantes.

(1) Le bien-être total lié au marché du gaz est très sensible à la demande de gaz et aux chocs d'offre de GNL dans l'UE. Bien que l'augmentation de la demande de référence puisse accroître la prospérité de l'UE liée à la consommation de gaz en raison de conditions d'approvisionnement abondantes et flexibles, le bien-être de l'UE est très sensible aux conditions d'offre de GNL.

(2) La mesure la plus efficace pour exercer une pression concurrentielle sur les fournisseurs de gazoduc de l'UE et pour améliorer le bien-être de l'UE consiste à assurer un accès transparent au GNL au MIG de l'UE. Mis à part le concept de partenariat stratégique, ce n'est que dans le scénario de sensibilité à la surabondance de GNL que nous avons pu simuler des diminutions notables des prix de gros du gaz. Une surabondance de GNL associée à un scénario de mise à disposition de capacités combinées pourrait réduire les prix de gros de l'UE. Les versions du scénario de réforme tarifaire qui augmentent les tarifs d'entrée du GNL sur le réseau de transport de l'UE sont très néfastes pour le bien-être de l'UE.

(3) Une fois construit, l'impact de Nord Stream 2 sur le bien-être des consommateurs de l'UE dépendra de la décision unilatérale de la Russie d'utiliser (ou non) le réseau de gazoducs de transit ukrainien. D'après les scénarios réglementaires réalistes, la réforme tarifaire semble être le remède le plus efficace pour atténuer la forte

divergence de prix que Nord Stream 2 devrait créer entre l'Europe du Nord-Ouest, l'Europe centrale et l'Europe du Sud-Est.

Recommandations

Les analyses présentées dans cette étude soutiennent les recommandations politiques suivantes.

- Modifier les paragraphes 6 et 7 de l'article 8 du règlement 2017/459 afin d'augmenter la part de la capacité technique existante que des GRT sont tenus de mettre de côté et d'offrir aux enchères pour des durées annuelles ou plus courtes de 50% ou plus. La même approche consistant à augmenter la part des durées annuelles ou plus courtes de 10% à 50% devrait également être envisagée pour la capacité supplémentaire au sein de l'UE afin d'éviter une future fermeture du marché.
- Examiner la mise en œuvre intégrale du scénario combiné de la mise à disposition (release) des capacités et du gaz. Cela impliquerait la modification du règlement 2017/459 comme indiqué dans l'ancienne recommandation et la mise en œuvre des programmes de libération de gaz pour les CLT existants et futurs dans les pays d'entrée de l'UE pour les produits de CLT.
- Examiner la mise en œuvre du scénario de réforme tarifaire après en avoir affiné les conditions de conception et de mise en œuvre telles que présentées dans l'étude. Les conceptions avec des tarifs supplémentaires différenciés par l'entrée dans l'UE, les points de sortie de l'UE et les points de sortie nationaux ainsi que les problèmes de mise en œuvre des CLT devraient être examinés plus en détails.
- Inclure le concept d'un partenariat stratégique potentiel - et la libéralisation correspondante du secteur gazier russe - à l'ordre du jour du futur dialogue énergétique entre l´UE et la Russie sur les négociations Nord Stream 2 ou DG Concurrence dans le but de promouvoir un secteur gazier européen compétitif en amont.

1. INTRODUCTION

The natural gas market has significantly developed over the past years towards fulfilling the main EU energy policy objectives: competitiveness, competition, security of supply and sustainability. This is being achieved predominantly by the Third Energy Package, which has been implemented, and some of its latest features are still in the process of implementation in the EU Member States. The package represents a legislative framework for the gas market with the main focus on transparent and non-discriminatory cross-border access to transmission networks facilitating gas trading across the whole EU, with the expected benefits of affordable and reliable gas supplies to end consumers. This new regulatory setting was expected to lead to a increase in gas market liquidity, decrease in gas price location spreads and an increase in the security of supply, and thus to greater EU welfare.

This report focuses on the qualitative assessment of the gas market after the full implementation of the Third Energy Package, and of the various additional regulatory measures which are designed to overcome the remaining, in this report identified shortcomings and are expected to further improve EU welfare. Consequently, the proposed regulatory changes are quantitatively modelled and their welfare impact is assessed and compared to the Reference Scenario.

Chapter 2 of this report summarises the methodologies applied for the quantitative and regulatory analyses in this study. The quantitative analyses were applied in order to identify, explain and quantify the welfare implications of the remaining market inefficiencies assuming the full implementation of the Third Package. The objectives of the regulatory analyses were to assess whether current market inefficiencies are sufficiently addressed by the regulation in force, and if not, what feasible additional regulatory measures could bring a significant improvement in overall EU welfare.

Chapter 3 describes the current functioning of the EU gas market and the future relevance of the following major gas market inefficiencies:

- EU upstream market concentration, where we observe high and growing import dependence and a simultaneous high import share concentration
- Long-term contracts impact and the related member state level upstream market concentration and potential market foreclosure
- The current level and structure of cross-border tariffs
- Physical, regulatory and contractual constraints to infrastructure access
- Local specifics in implementing the Third Energy Package rules

Chapter 4 discusses the efficiency of the current regulation to address obstacles to improved market efficiency with a special emphasis on (i) measures to address EU level upstream market concentration, (ii) tariff pancaking as addressed by voluntary market mergers and the Tariff Network Code, and (iii) physical, regulatory and contractual constraints to network access.

A Reference Scenario is then defined in Chapter 5 to assess and estimate the impact of the analysed alternative regulatory scenarios. This is built on the market situation expected in 2020, with further adjustment of certain parameters and assumptions in a sensitivity analysis to reflect their anticipated development in the future. The identification of the inefficiencies represents a current qualified estimate of the expected future market situation after full Third Energy Package implementation which could, however, develop differently than projected with a corresponding impact on the conclusions being made and on the definition of alternative scenarios.

Five alternatives are proposed in Chapter 6 to address the identified shortfalls:[3]

- Tariff Reform Scenario, where intra-EU cross-border tariffs would be eliminated and revenues from the EU-border tariffs would be reallocated to the TSOs to cover their justified revenues
- Trading Zone Merger Scenario, which discusses the possibilities of merging existing market zones
- Conditional Market Merger Scenario, where neighbouring zones would remain merged with a single wholesale market price as long as transmission capacity is available
- 'Combined Capacity-Commodity Release' scenario, where part of long-term contracted gas would be delivered at the first trading point following its EU entry and the intra-EU delivery point and routes would be largely dismissed from the long-term contracts on gas supply
- ‘Strategic Partnership’ concept, where the EU and its extra-EU gas supplier partners would enter into a mutually beneficial agreement to integrate their gas markets in a fundamental way. This is a cooperative regulatory concept aiming at improving the combined welfare of the EU and its major pipeline suppliers, most notably Russia

These measures are analysed and described in the level of detail required for the explanation of their main features, the reasoning behind their selection and their potential impact. The scenarios are analysed from an economic and market regulatory perspective. Specific legal, technical, tax or other analyses have not been performed.

Furthermore, additional scenarios had been considered, but were not included as main alternative scenarios as they are not expected to provide substantial economic benefits and increase EU welfare or impact only on a limited part of the EU market. The additional considered scenarios include a full market merger, long-term (LT”) capacity contract limitation, implicit auctions, storage at virtual trading points, no third party access (TPA) exemptions, Regional Operating Centres with a mandate to implement projects of common interest (PCI) infrastructure, and minimum bi-directional flow obligations for a proportion of dominant flow capacities.

Chapter 7 summarises the results of the quantitative welfare analyses performed by the EGMM on the alternative regulatory scenarios presented and discussed in Chapter 6. For each alternative scenario we apply four standard measures to describe the changes that their implementation implies on the 2020 reference scenario values. These are total welfare change, consumer welfare change, the change in EU weighted average gas wholesale price level and in price divergence. We also define five sensitivity scenarios and assess the welfare impacts of a selected set of alternative regulator scenario implementations on those sensitivity scenarios. The five sensitivity cases are related to high demand, high and low LNG supply and two alternative Nord Stream 2 project implementation situations. The chapter concludes with a policy-oriented discussion of our findings.

[3] Scenarios denote a modification of the internal EU gas market regulatory. With “concept” we denote an example of how the combined welfare of the EU and its major pipeline suppliers might be significantly improved when a cooperative concept would be implemented.

2. METHODOLOGY

This Chapter summarises the methodologies applied for the quantitative and regulatory analyses in this study. The qualitative analyses were applied to identify and explain 2016 gas wholesale price differences and related market inefficiencies on the EU market. The price and welfare impacts of the proposed alternative regulatory scenarios were quantified by market simulation using the EGMM. The objectives of the regulatory analyses were to assess whether current market inefficiencies are sufficiently addressed by the regulation in force, and if not, what feasible additional regulatory measures could bring significant improvement in overall EU welfare.

The European design of an integrated internal gas market aims at reaching efficient competition and a resulting competitive outcome on the product market, which is the lowest possible cost-reflective wholesale price. The principal market design components are full retail choice, cross-country market integration and non-discriminatory regulated third-party access to the unbundled transmission grid. Framework rules are harmonized at the EU level with limited discretion of implementation at the Member State level. Market design implementation assumes a high-level cooperation and coordination among TSOs and NRAs.

We start our analyses with a brief description of market efficiency theory as applied to regulated utilities markets (Section 2.1). Subsequently, we provide an assessment of currently remaining inefficiencies in gas wholesale market functioning. To do so, we first present a survey of recent literature on gas market operation efficiency in the EU (Section 2.2 and Annex 3), and based on its conclusions, we introduce a methodology and related measures for additional analysis in Section 2.3. We present the results of the analysis based on this methodology in Chapter 3. The focus of the market analysis is on evaluating the exposure of the EU gas market to powerful outside suppliers, identifying remaining obstacles to intra-EU gas trading and judging the contestability of member state gas wholesale markets.

Section 2.4 describes the approach we apply in assessing the efficiency of existing regulatory measures (Network Codes, Guidelines) to address remaining inefficiencies in gas market functioning.

Section 2.5 introduces the methodology of regulatory scenario identification and development.

Finally, in Section 2.6, we introduce the market modelling methodology and assumptions we apply primarily to assess the social welfare and other economic impacts of the gas market regulatory scenarios addressing remaining market inefficiencies (described in detail in Chapters 6 and 7), once implemented. The concept and components of social welfare as understood in this study is defined, as well as the methodology to quantify it.

2.1 Market efficiency theory specific to regulated utilities markets

Utilities are organizations which are characterized by maintaining large and costly infrastructure for a service and/or providing the service using that infrastructure. Given the nature of the infrastructure, such businesses have typically been considered natural monopoly sectors. Historically, utilities constituted primarily rail, gas, electricity, mail and telephone. More recently, the utilities include telecommunications, broadcasting, and data transfer in general. Utilities thus can be broadly defined as an industry where a good or service is delivered through a certain visible or invisible route or network. The network itself can then be defined as a certain transport route (e.g., water distribution network, electricity network, road, telephone wire, gas pipeline, etc.) through which these goods or services such as passengers, electricity, water, gas or data are transmitted.

The most profound reason for market inefficiencies amongst utilities is the presence of natural monopolies. Most of the utilities require significant infrastructure, which is expensive to build and maintain. The high portion of fixed costs relative to the variable costs leads to the total average costs to significantly decrease with the quantity. These economies of scale lead to significant cost advantages for big market players. Ultimately, this drives down the number of players in the market and leads to a monopolistic market structure (Perloff (2012)).

Together with extremely high barriers of entry, and thus problematic contestability of these markets, this can lead not only to sub-optimal allocation of resources in the form of higher prices and lower quantity for end-customers, but also to underinvestment and inefficient utilisation of the underlying infrastructure network. In other words, low value for money for the end-customer, as he would be using obsolete infrastructure for a non-competitive price.

2.1.1 Regulation

The presence of market inefficiencies is one of the main reasons for need of regulation, next to strategic considerations. The regulation should correct such failures and allow for a more efficient allocation of resources or other political/social goals. The ideal goal of a well-functioning economic regulation is to ensure the delivery of a safe and appropriate service, while not discouraging the effective functioning of the market.

However, it is not a trivial task for the policy maker and the regulator to set an appropriate level of regulation for a given market. It is necessary to regulate and correct only where the market inefficiencies occur and let the competitive forces drive the market where possible.

Historically, the natural monopoly characteristics of utilities were a reason for state ownership or strong regulation of these companies. Typically, the utilities were operating in the form of a vertically integrated monopoly. However, due to the stagnating competitiveness of utilities, the academic perception of this model changed. In the 1990s, the process of deregulation and vertical restructuring started to take place. With all utilities, there exists at least a possibility to realise competitive supply, i.e., an entry in the sales or some production phase. Depending on the particular market, the previously vertically integrated monopolies were split into (i) activities which are facing competitive forces, and thus can be to some extent deregulated and (ii) the infrastructure itself (natural monopoly activities) which is regulated separately. This process is called unbundling and has been already at least partially realised in most of the developed markets and serves as a good example of the need for regulation in the energy industry (Mejstrik (2004)).

2.1.2 Conclusion

A well-functioning market adjusts the behaviour of its participants through price mechanisms and leads to a Pareto efficient outcome, which can be then through transfers brought to a politically desirable, efficient and equitable outcome. However, utilities including gas transmission are a typical example of natural monopoly and by definition thus operate under imperfect competition. The policy maker must assure through regulation that the market works efficiently, motivates efficient system use, allows for efficient investment process, considers overall system costs and internalises externalities, and not in the last place considers unintended consequences of regulation. Hence, an efficient market should from our perspective:

i) Provide transparent information, correct pricing signals and incentivise participants to behave alongside them,
ii) Incentivise investments by fair payment and also high asset utilisation,

iii) Have clearly defined market and regulatory rules and not contain excessive complexity,

iv) Foster competitive market structure and reduce barriers,

v) Be cost efficient, providing good value to market users,

vi) Be resilient and provide certain security of supply.

2.2 Conclusions of a literature review on gas market operation efficiency in the EU

In the context of this study, we carried out a careful literature review evaluating the efficiency of current gas market functioning in the EU. Annex 3 contains the full text of the survey. The conclusions of the literature review can be summarised under the following statements.

1. There is a broad agreement that price convergence is one of the most important signs of an integrated and well-functioning gas market. High-level price convergence signals that there are no serious barriers to trade which would prevent market participants from buying gas where it is cheaper and selling it where it is more expensive. For traders to be able to do that, the market needs to meet two basic requirements: there needs to be an appropriate venue for trading with a high level of competition (i.e., liquid hubs); and an efficient infrastructure must be there to make the physical delivery of gas possible, when necessary.[4]

2. Infrastructure-related efficiency requires that there is enough physical capacity connecting markets, but also that these capacities are used in an efficient way. The efficient use of infrastructure is, again, a complex requirement that comprises several issues:

   – the price of using the infrastructure, which should be low enough not to hinder trade, and high enough to cover the costs of their operators;
   – the allocation of existing capacities, which should prevent market foreclosure (i.e., when booked long-term capacities remain unused and create contractual congestions);
   – another aspect of the allocation of existing capacities that is related to the management of physical congestions: auction mechanisms should be in place to provide investment signals for system operators and to ensure that the infrastructure is used by those who value it most;
   – the allocation of future capacities, which should ensure that investment costs will be recovered without risking market foreclosure (i.e., when future capacities are booked long-term by a dominant market player, preventing that a sufficiently significant part of those capacities may serve to strengthen competition through short-term trade).

3. Sustained price differences between markets can therefore signal potential inefficiencies. The most obvious is a lack of sufficient physical interconnectivity, which, although to a lesser extent than before, still accounts for higher gas prices in certain parts of Europe. The lack of infrastructure may lead to a concentrated market, where a dominant supplier – free of competitive pressure in the absence of alternative sources – can impose its market power.

[4] Liquid hubs with a wide range of products may be able to offer alternatives to physical delivery, e.g., through swap deals.

4. Historic long-term contracts hinder competition even when alternative sources become available. However, the portfolio optimisation of over-contracted European buyers has boosted the liquidity of EU hubs in recent years.

5. Countries with a dominant supplier were less likely to develop a liquid trading venue, an easy access to which is a pre-requisite to the emergence of a competitive wholesale market. Liquid hubs are essential in the transition towards more short-term contracts, which characterise a truly competitive wholesale market. We do not imply that longer-term contracts necessarily hinder competition, but a well-functioning short-term market needs to exist to provide liquidity and price signals that ensure that long-term contracts are priced fairly. Ideally, as hubs develop, they also make more and more longer-term products available for trading.

6. If interconnectivity is not an issue, access to alternative sources and/or more liquid hubs depends on regulations related to the use of infrastructure. Some of the inefficiencies cited in literature in this field are also rooted in the dominant position of a supplier: long-term contracts may cover not only the supply of the commodity itself, but the booking of capacities on the route of delivery to the buyer as well. Even if there is competitively priced gas available for short-term trading in a connected market, long-term capacity bookings may prevent the delivery of that gas to the potential buyers' market. Long-term bookings by a dominant supplier may result in contractual as well as physical congestions, and congestion management practices are deemed inefficient by many market participants.

7. Currently entry and exit tariffs are charged whenever the gas crosses the border between market zones, which are identical to national borders in most cases. This "pancaking" of tariffs raises the cost of trading across national borders and reduces price convergence.

2.3 The methodology to assess currently remaining inefficiencies in gas wholesale market functioning

Based on the above conclusions drawn from a literature review, we have developed a methodology to assess the efficiency of gas markets at the level of individual Member States.

2.3.1 Analytical framework

Our analysis focuses on price, which is the ultimate market performance indicator since it is directly related to social welfare. Targeting the lowest possible price through effective competition is reasonable not only because the production of natural gas takes place predominantly outside the EU, but also as it maximises allocative efficiency (minimise deadweight loss). Although it is unequivocal that the welfare maximising price is the lowest possible price, it is highly unclear, however, what level of price would reflect close-to perfect competition, and therefore how far the EU gas market stands from efficient market functioning.

The price for the final consumer is formed along the whole value chain, but for this study we find it most appropriate to examine the purchase price (i.e., sourcing cost) of the wholesalers on the national markets. These midstream companies have access to various sources, e.g., domestic production and import (via pipeline or LNG), and sell gas to inland retailers and large industrial customers. In this analysis, by 'wholesale price' we mean primarily the price the midstream companies pay for the gas to upstream companies.

We argue that two structural characteristics should be analysed in detail in order to form a conclusion on the level of the midstream purchase price from a welfare point of view:

1. The market power of dominant outside suppliers on the individual national or regional gas markets, which might lead to prices well above the competitive level; and
2. The integration of the individual national or regional markets, which can mitigate the above-mentioned exposure through providing access to multiple sources.

In our understanding, prices differ across countries because of the diverse supply and demand conditions, out of which the market structure and market power at the upstream level are the most distinctive factors. Therefore, market integration in our approach is not a goal, but only a mitigation tool against exposure to dominant suppliers with significant market power. If the physical, contractual and regulatory barriers to trade between countries diminish, exposure loses its meaning at the national level, since wholesalers have access to all gas sources in a fully integrated (single) market.

We note though, that even the maximum degree of market integration does not grant a competitive price level in itself, it only means that the price levels are identical across the member states. It follows that pivotal positions should be further analysed at the level of the integrated market (optimally, at the EU level). We can assume that market integration leads to lower prices mainly because larger markets are less likely to be dependent on dominant suppliers. In this approach, market integration is the solution of the welfare maximisation task assuming a given structure of external sources, while the whole solution also contains diversification of sources to achieve a more competitive upstream market.

2.3.2 Steps of the analysis

In accordance with the outlined framework, we begin our analysis with examining market integration by calculating price differentials between neighbouring EU countries, based on data published by the European Commission in its quarterly reports on European gas markets. Price differences tell us which national markets are integrated at a level that it is reasonable to assume they are functioning as one market, and which markets are separated by trade barriers.[5]

We continue then with looking at the trade barriers, starting with the transport costs. In a fairly integrated market, price differentials between neighbouring countries should not exceed the cost of transporting gas from one to another. We use the tariff database of the EGMM for estimating the cost of gas transportation across the borders within the EU. However, our estimated transport costs do not reflect two possible elements of the tariffs: the sunk costs and the congestion fees.

On the one hand, as secondary capacity markets are not liquid, traders with long-term commodity contracts and connected long-term capacity bookings with ship-or-pay clauses face obstacles at selling the superfluous capacities. In this case, they can perceive the transport costs as sunk cost, and thus the marginal costs of transport as zero. If they do so, it is rational for them to transport gas until the price differences cease entirely. This situation explains price differences below real transport cost (even zero in some cases), which we can call full market integration.

On the other hand, higher price differences can suggest congestion, which materialises as auction premia in capacity auctions or as capacity hoder's rent in existing booking and in insufficient flows between markets. Where we discover price differentials exceeding the estimated tariff levels, we first check whether they are a "simple" interconnectivity issue.

[5] With reference to the phenomenon of relevant market in competition law, where the relevant geographic market comprises the area in which the conditions of competition are sufficiently homogeneous and which can be distinguished from neighbouring areas because the conditions of competition are appreciably different in those areas. (Commission Notice on the definition of relevant market for the purposes of Community competition law, 97/C 372/03, 8.)

We analyse ENTSOG data on interconnection capacities and flows. If there is no sign of physical congestions, we look for evidence of contractual ones by analysing long-term booking levels.

We also consider the role of the long-term supply contracts with take-or-pay clauses, which affect indirectly the congestion through connected capacity bookings, but more importantly, can directly decrease the short-term contestability of the market. If national wholesalers are engaged to one supplier for the long term, they don’t have the incentives to purchase from more competitive sources. Moreover, if the competitive sources are limited (regarding either commodity or transmission capacity), the contestability problem may persist for a longer term, since the dominant supplier will be able to extort high minimum take-or-pay levels (compared to consumption or import need) for the next LTC period too. Such customer foreclosure strategies can successfully prevent market entries (sometimes by creating de facto exclusivity), and connects the issue of market integration with another market feature in scope: exposure to dominant suppliers.

According to our view, barriers to trade explain price differences only by maintaining the diverse supply and demand conditions, especially the market power of the upstream companies. Theoretically, if the market conditions are similar (including the case when two countries have access to the same import sources), the price differences can be much lower than the transport costs, and in this case, price convergence is not a result of trade. Conclusively, it is pivotal supplier position and lack of market integration that together lead to high price differences.

Therefore, the next part of our analysis covered by Chapter 3 focuses on the characteristics of the higher priced markets and trading zones (countries which are assumed to function as one market based on low price differences).

Firstly, we analyse midstream supplier market concentration at a company level, using relevant HHI values provided by ACER. We assume that differences in supplier-side market concentration can affect the sourcing costs of the national wholesalers. But considering the fact that exporter companies have access partially to the same original sources, the company level market concentration presumably does not catch the market power problem entirely. To address this problem, we also check the diversification of supply sources.

We complement this Member State level analysis with calculations of price zone and EU-level upstream market concentration focusing on the extra-EU net import needs.

2.3.3 Drawing conclusions

In sum, our methodology for assessing EU gas market functioning from a welfare point of view is the following:

1. Examining country level midstream purchase price differences to define the fully integrated markets (price zones) and to identify borders with barriers to trade.
2. Analysing trade barriers between neighbouring countries and price zones, such as:
    a. transport cost (disregarding sunk costs and congestion fees; markets assumed to be sufficiently integrated if price differences do not exceed that narrowly defined transport cost),
    b. physical congestions (interconnectivity issues),
    c. contractual congestions (the role of long-term capacity booking) and
    d. market foreclosure (the role of long-term supply contracts).
3. Assessing upstream market power and exposure to dominant suppliers with regard to the defined price zones by:
    a. presenting market concentration indicators (HHI) at company level and diversity of supply source metrics, and

b. analysing upstream exposure at the price zone and EU level by calculating HHI taking into account the primary extra-EU import sources.

Based on the above indicators, the EU market can be considered highly well-functioning if:

- As a result of removing intra-EU trade barriers, price differences between neighbouring countries do not exceed transport tariffs without congestion fees, and
- Upstream market concentration at EU level stays below certain thresholds.

If only the first condition is met, we consider the market to be sufficiently well-functioning, since the market integration prevents the emergence of excessively high prices by levelling the market conditions among Member States.

If the first condition is not met, then the country level market concentration makes the difference between moderately and poorly performing markets:

- Observable price differences between competitive market indicate diverse supply and demand conditions that are not directly related to competition and market functioning (such as different production costs), while
- The parallel presence of barriers to trade and upstream market power is a clear sign of poormarket performance.

2.4 The methodology to assess the efficiency of existing regulatory measures (Network Codes, Guidelines) to address currently remaining market inefficiencies

After identifying inefficiencies in the current market functioning and their likely causes, we ask the question of how effectively the present regulatory framework addresses those inefficiencies.

The basic framework for the regulation of the European gas market is the 3rd Energy Package, which came into force in 2009. The 3rd Energy Package consists of two Directives and three Regulations:

- Directive 2009/73/EC concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC
- Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005
- Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators

The whole package includes several other measures, such as national legislation, network codes and guidance.

Based on Regulation 715/2009, ENTSOG has to propose Network Codes including the fundamental rules governing cross-border gas trading. In particular, it concerns rules on transparency, balancing rules, capacity booking and harmonised transmission tariff setting. The specific list of items is set out in Article 8 (6) of the above Regulation.

To date, only a part of the legislation set forth in the aforementioned list is published; namely Congestion Management Procedures Guidelines (CMP GL) as part of the above-mentioned Regulation, Commission Regulation establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems (984/2013/EU, respectively 2017/459) (CAM NC), Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules, Commission Regulation establishing a Network Code on Gas Balancing of Transmission Networks (312/2014/EU) (BAL NC) and Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (TAR NC). Not all articles in accepted network codes are in force. For example, TAR NC will only come into full force after 2019. However, in the study we are working with the published codes, regardless of the exact date of applicability and looking at what impact their full implementation should have.

We focus on the different network codes from two points of view. Firstly, whether the full implementation of the adopted network codes can effectively mitigate the inefficiencies identified by the study and which inefficiencies may remain. Secondly, whether the network codes themselves do not create new inefficiencies in the gas market.

We approach the analysis at a theoretical and a practical level. At the theoretical level, we investigate how the specific code is dealing with the current market situation. This includes the assessment whether the code is expected to address inefficiencies. The second level is the practical view by asking whether the codes already in place and applied (CAM NC, CMP) are actually acting to eliminate inefficiencies in individual markets. Next, we also assess whether the inefficiency is addressed by the code intentionally or in combination with other measures, even though it did not have to be an objective when creating a code.

2.5 Description of the approach to alternative scenario formulation and selection

The aim in developing the alternative regulatory scenarios is to address the most of the identified market inefficiencies in a limited but diverse regulatory scenario set. When formulating the alternative scenarios, we have reviewed and considered the past European gas target model discussions, the main suggestions presented in Quo vadis discussion papers by other tenderers as summarised in Annex 8, discussions with market participants and their feedback and included our own considerations. The conditions considered were the following ones:

1. Addressing crucial identified market inefficiencies

   The basis for considering alternative regulatory scenarios is to address existent market inefficiencies as identified and described in this study.

2. Significant change in at least one regulatory aspect

   We understand that the objective of the Quo vadis project is to propose significant path-changing regulatory modifications (assuming they are necessary) in order to improve EU welfare and address existent market inefficiencies that cannot be addressed within the current regulatory EU framework. Therefore, we have considered only those alternative scenarios where the regulatory change is fundamental (i.e., significant change of tariff scheme, of capacity booking scheme or gas release program). All of the selected alternative scenarios provide a regulatory change in at least one of the key parameters, such as zone setting, tariff structure or regulation methodology.

   In proposing the alternative scenarios, our aim was to change only one major characteristic, if possible.[6] This approach allows us to carry out ceteris paribus modelling to compare the welfare gain of individual regulatory changes and to select the most beneficial one for the EU.

[6] Due to the complexity of some of the proposed significant changes, we have to propose certain additional accompanying changes within the alternative scenarios so that they are viable.

3. Expected significant EU welfare gain

   One of the key selection criteria is whether the implementation of an alternative regulatory scenario is expected to bring significant EU welfare gain by addressing crucial identified market inefficiencies. The potential EU welfare gain of each scenario is assessed qualitatively first. The scenarios presented in Chapter 6 are those we selected for quantitative welfare analysis by the European Gas Market Model (EGMM). Scenarios with expected insufficient welfare gain have been rejected.

   This consideration means that by targeting improvement of existent or expected market inefficiencies, the alternative regulatory scenario will be successful and will further not create any new significant market distortion or inefficiency.

4. Implementation feasibility

   Even though implementation feasibility was not the main criterion in selecting the alternative scenarios, we perceive this characteristic to also be essential. We understand that individual market players and decision makers often have contradictory interests and that historically the negotiation process related to any of the main regulatory changes was lengthy and demanding.

   Implementation of the selected scenarios presented below would be challenging and support from each of the market participants is not self-evident. However, based on this criterion, we have rejected only those scenarios that we understand, based on our assessment and discussions with market participants, to be completely unfeasible and also not rewarding (e.g., full market merger). If according to our analysis, an implementation of an alternative scenario would be feasible or there is historical evidence that similar regulatory change has already been implemented or is currently being implemented (such as regional mergers), we perceived this scenario implementation as feasible and do not reject it based on this criterion. Nevertheless, we comment on the feasibility in each individual scenario.

Scenarios are elaborated on in detail in Chapter 6. They are followed by an example of additional regulatory measures to be considered for implementation alongside the regulatory scenarios.

A shorter assessment of additional, not selected scenarios is presented along with reasoning why these scenarios are not further considered.

2.6 Methodology to assess the social welfare impact of future regulatory changes

The main tool for our evaluation of the selected and proposed future regulatory scenarios is gas market simulation. This Section summarises the fundamental characteristics and assumptions underlying our simulation tool, the EGMM. Due to its outstanding importance for this study, we provide an extended explanation of the welfare concept and calculation inherent to EGMM. We briefly reflect on the scenarios we define, analyse and compare, and the scope of related sensitivity analyses.

2.6.1 Competition and welfare in the European Gas Market Model

The European Gas Market Model (EGMM) is a competitive, dynamic, multi-market equilibrium model for natural gas production, trade, storage, and consumption in Europe. It explicitly includes a supply-demand representation of 33 European countries, including all continental EU countries, Ireland, and the UK, but not including Malta and Cyprus.

Norway is not modelled and is not part of the welfare calculations. Switzerland, Turkey, and Energy Community Contracting Parties[7] (except for Georgia) are modelled but are not part of the welfare calculations. Each country is one node, one market zone.

EGMM includes the modelled countries' gas storages and transportation links to each other and to the outside world. EGMM considers only TSO level trade and flows, but DSO zones are not reflected. The time frame of the model is 12 consecutive months, starting in April. Market participants have perfect foresight over this period.[8]

2.6.1.1 Competitive equilibrium

The European Gas Market Model simulates a competitive natural gas market with the following active participants:

1. Consumers
2. (Local) producers
3. Gas importers with long-term take-or-pay contracts
4. Traders

Consumer decision making is embodied in the demand curves. All other players are price-takers: they do not calculate with the possibility that their decisions can alter the market prices.

In the competitive equilibrium, all supply-side participants maximise their discounted monthly profits over 12 months subject to the physical constraints and the infrastructure usage fees in the system. By the first theorem of welfare economics, the competitive equilibrium coincides with the allocation that maximises the joint surplus of all active market participants.

In contrast to the active players (consumers, producers, importers, and traders), transmission and storage system operators (TSOs and SSOs), as well as LNG regasification terminals, are passive participants in the market. Their usage fees, capacities, and costs are all exogenously given parameters in the model.

2.6.1.2 Total surplus of active market participants

The total surplus (or: welfare) of active market participants is defined as the (discounted) difference between what consumers are willing to pay for natural gas and the variable costs of production, long-distance imports, transportation and storage. The basic idea is simple: if an extra 1 MWh of natural gas is worth EUR 100 to a consumer, and it only costs EUR 30 to extract, transport, and store it, then its consumption must create a total surplus of EUR 70. The fixed costs associated with existing infrastructure are excluded from the surplus calculations. These costs are the same in all model scenarios, hence they always cancel out when we look at welfare changes from one scenario to another.[9]

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[7] Albania, Bosnia and Herzegovina, Georgia, the former Yugoslav Republic of Macedonia, Kosovo (in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence), Moldova, Montenegro, Serbia, and Ukraine

[8] For a detailed model description, see Kiss et al. (2016).

[9] The exclusion of fixed costs means that the absolute value of total surplus in itself has no useful practical interpretation. However, this consequence is unavoidable. Even if we had perfect information about the fixed costs of existing infrastructure, the limitations of our knowledge about the entire demand function (including its shape at prices that have never been observed before) would not allow us to get a reliable money-equivalent

Depending on market prices and transmission and storage conditions, the total surplus in the model is shared between consumers, producers, importers, and traders in the form of:

1. Consumer surplus [to consumers]
2. Producer surplus (or: short-run profit excluding fixed costs) [to producers]
3. Profit on long-term contracts [to importers]
4. Profit on cross-border spot and backhaul trading [to traders]
5. Profit on intertemporal arbitrage via gas storage [to traders]

Let us illustrate these concepts through a minimal example with three countries (A, B, C) and two periods (P1, P2). Consumption only takes place in A in P2, production in B in P2, long-term imports come from C to A in P1, and spot trading is only possible between A and B. In addition, there is a gas storage in A, and the interconnector from B to A is possibly congested, but the one from C to A is not.

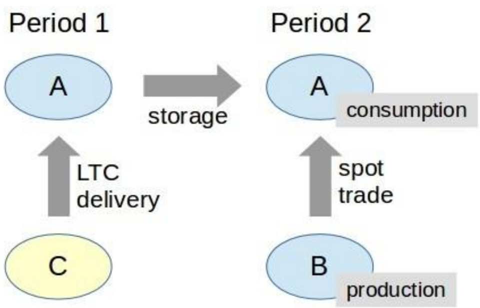

Figure 1: A stylised network to illustrate welfare components

The relationship between the various components of total surplus derived from Figure 1 is shown in Table 1. For simplicity, we assume that transmission fees are only levied on cross-border trade, but not on the entry and exit of production, consumption, and storage.

Welfare component	Verbal definition				
Consumer surplus (using P2 production from B)	what consumers in A are willing to pay in P2	–	what consumers in A have to pay in P2		
Spot trading profit	what consumers in A have to pay in P2	–	what producers in B receive in P2	–	transmission fees from B to A in P2
Producer surplus	what producers in B receive in P2	–	what it costs in B to produce in P2		

estimate of the real-life welfare generated in the market. Changes in real-life welfare, on the other hand, can be approximated without any information on fixed costs. See also the subsequent discussion of consumer surplus.

Welfare component	Verbal definition				
Consumer surplus (using P1 imports from C)	what consumers in A are willing to pay in P2	–	what consumers in A have to pay in P2		
Storage arbitrage profit	what consumers in A have to pay in P2	–	what importers receive in P1	–	storage fees from P1 to P2
Profit on ToP contracts	what importers receive in P1 (in A)	–	what importers pay in P1 (in C)	–	transmission fees from C to A in P1
Total surplus of active market participants	what consumers in A are willing to pay in P2 (for B's production and C's imports)	–	what it costs to produce in B and import from C	–	transmission fees from B to A and C to A, and storage fees from P1 to P2

Table 1: Welfare components collected by active market participants

Note: All cells must be discounted to the same period before netting

Below, we provide a more detailed description of how each welfare component is calculated.

2.6.1.3 Consumer surplus

Consumer surplus[10] is the difference between what consumers are willing to pay for natural gas, and what they actually pay.

The willingness to pay is embodied in the demand function, which we define for all periods and markets. Since the demand function shows what people would be willing to pay for an additional unit of natural gas at any consumption level, the total value of gas consumed is given by the area beneath the demand function. From this, we subtract the amount paid (the market price multiplied by the quantity consumed), to arrive at the consumers' surplus. This is the measure in the model that best reflects the well-being that consumers derive from participating in the gas market.

At a practical level, we use a linear demand specification with assumed demand elasticity parameters, which is calibrated to typical price levels and quantities. This functional form is a convenient one for computational purposes and allows us to introduce more detail in other parts of the model. It is likely to be a good *local* approximation for the willingness to pay for gas, but does probably yield biased results at extremely high market prices (just as any other computationally feasible functional form would). As a result, *changes* in consumer surplus between various scenarios are more instructive to look at than absolute levels of consumer surplus in any given scenario.

2.6.1.4 Producer surplus

Producer surplus is the difference between what producers receive for natural gas in revenues and what it costs them to extract the gas in the short run.

Revenues are the product of the market price in the producers' locality and the amount of energy sold. Short run variable costs are mainly understood as a variable OPEX component.

[10] The economic terminology often distinguishes between gross and net consumer surplus. The former denotes the total value of consumption, without considering the amount paid for the product. We use the term consumer surplus in the net sense (i.e. the value of consumption net of the amount paid for the product).

The difference of these revenues and costs measures the incremental profit that a producer gains by selling into the market, as opposed to leaving the gas under the ground.[11]

2.6.1.5 Profit on long-term supply contracts

In welfare terms, gas imported through long-term supply contracts is like local production. Importers pay a set price for the gas at the delivery point, as well as all applicable transmission fees between the delivery point and the transmission system of the destination country. Transmission capacity is otherwise ensured, meaning that LTC importers do not need to participate in cross-border capacity auctions and do not generate congestion revenue for the TSOs.

Long-term supply contracts may have a take-or-pay clause, which mandates that a fraction of the agreed price must be paid even if no delivery is requested. By default, unused capacity bookings are released for spot trade, but the alternative ("ship-or-pay" contracts) can also be approximated by putting separate restrictions on the capacities available for spot trading.

2.6.1.6 Profit from cross-border trading

We assume no internal congestions within markets, and hence a single wholesale price prevails within the same locality. It is possible, however, that an interconnector is used up to capacity between two neighbouring markets, and therefore cross-border trading might not eliminate all price differences in excess of transmission fees. Traders buying in the cheaper market and selling into the more expensive one will reap the price difference minus the transmission fee as profit.

Profit might also arise on trading in virtual reverse flow (backhaul). When gas flows physically from a high-priced to a low-priced market because of long-term supply commitments, it might be possible to sell the gas before it reaches the low-priced market and profit from it. TSOs offer backhaul capacity for this purpose at pre-set fees, and traders selling in the expensive market will again collect the price difference minus the backhaul fee as profit.

There is an alternative interpretation of the surplus generated by cross-border trade in either direction. Traders compete with each other for this margin and hence are willing to bid in a capacity auction up to this amount to gain access to the transmission capacity. Even though the TSOs are not active participants in the model, they will eventually end up with the congestion rents accruing on the cross-border pipelines.

2.6.1.7 Profit from intertemporal arbitrage via storage

If there are sufficient price differences in excess of storage fees between periods, then traders will utilize underground gas storages to profit from these margins. Since traders compete with each other, arbitrage profit from storage use will only arise if there is insufficient storage, injection, or withdrawal capacity to bring down the (discounted) price differences to the level of storage fees. In a way, this profit is perfectly analogous to the congestion rent described in the previous section, except that arbitrage is across time, rather than across space.

[11] We disregard the option value of gas left under the ground. In addition, our short-run cost estimates are only indicative because of insufficient information about the extraction process. As a result, the same caveat applies to producer surplus as to consumer surplus: Changes between various scenarios are more instructive to look at than absolute levels in any given scenario.

Similar to cross-border trading, the rents arising from storage capacity shortage might be captured by storage system operators if they use auctions as capacity allocation methods.

2.6.1.8 Total surplus of passive market participants

Finding the competitive equilibrium of the model is equivalent to maximising the total surplus of active market participants, the elements of which we have detailed above. However, it would be incorrect to conclude that the surplus measure maximised by competition is all the welfare created by the market, because transmission, regasification, storage, and long-term contract prices and fees in the model are typically above the marginal costs of these activities, and hence also generate surplus (operating income) for infrastructure operators and gas exporters.[12]

Table 2 provides an overview of the various elements of total surplus that accrue to passive market participants.

Welfare component	Verbal definition		
TSO operating income	TSO revenues from entry and exit fees	–	variable cost of providing entry-exit services on the transmission network
SSO operating income	SSO revenues from injection and withdrawal fees	–	variable cost of injecting and withdrawing gas from storage
LNG operating income	LNG terminal revenues from regasification fees	–	variable cost of LNG regasification
Profit of LTC exporters	revenue from gas sold through LTCs (net of transmission fees)	–	value of exported gas in the home market of LTC exporters

Table 2: Welfare components collected by passive market participants (all cells must be discounted to the same period before netting).

2.6.1.9 Total surplus (welfare)

The overall surplus (welfare) generated in the gas market model equals the sum of surpluses by active and passive market participants. Within the model paradigm, this is the appropriate measure to consider when analysing the welfare effect of changes in model parameters.

2.6.2 Phases of scenario analysis

We perform the following phases of scenario analysis:

1. Definition and estimation of social welfare in the Status Quo scenario (2016 IGM market conditions). This starts with EGMM verification on the latest available data from 2016.

2. Definition of the Reference Scenario. This is the case when the current Third Energy Package legislation is fully implemented against the Status Quo, the latter representing the current IGM fundamentals (demand, infrastructure, regulations,

[12] Thinking about the surplus generated for passive market participants is especially important when considering the welfare effect of changes in infrastructure fees. Without considering the operating income of TSOs, for example, a decrease in transmission fees would have a direct positive effect on the total surplus of traders, but no offsetting negative effect on the surplus of TSOs, which would clearly be misleading. Changes in infrastructure fees should only affect total welfare if they lead to a change in infrastructure utilization.

etc.) and exogenous conditions (LTCs, outside supply sources and supplier strategies, oil prices). Assumptions about how NC implementation changes the conditions of gas market functioning is defined and built into the reference modelling scenario.

3. Estimation of social welfare change brought about by the Reference Scenario compared to the Status Quo. This welfare change indicates the welfare gains that the full implementation of the Third Energy Package might bring for EU stakeholders.

4. Estimation of social welfare changes by introducing additional regulatory changes to the Reference Scenario, ceteris paribus, that is by assuming no notable improvements or deteriorations in the IGM's endogenous or exogenous conditions compared to the Reference Scenario. These scenarios are called Regulatory Scenarios and are based on the analyses in Chapters 3, 4 and 5.

5. Definition and analysis of Sensitivity Scenarios. Main sensitivities are:

    a. Demand: reference: 10% uniform demand increase across the EU over reference demand (PRIMES REF)
    b. Supply: high and low LNG supply to Europe
    c. Key infrastructure: Nord Stream 2 implementation versions

2.7 Interaction with stakeholders in the Quo vadis project

During the project we had an intensive interaction with major stakeholders including: European Commission and national governments' representatives, NRAs, TSOs, SSOs, multiple gas industry organisations, consumer organisations, producers, midstreamers, retail companies, traders and commodity exchange representatives. We discussed with them their points of view on all the main assumptions and findings of this study, such as:

- Model methodology and assumptions
- Current gas market functioning
- Inefficiencies of the current gas market
- Reference scenario setting
- Alternative scenarios definition and results

In cooperation with the European Commission, two stakeholder meetings were organised in Brussels (in June and December 2017). During these meetings the main topics of the project were discussed and subsequently the stakeholders also had the opportunity to submit written comments to the study. As a result, we received comments from almost 40 stakeholders after the workshop in June and from nearly 30 after the workshop in December which have been taken into account when updating the study.

Moreover we have also organised an extra workshop dedicated specifically to modelling methodology and assumptions which was held in July 2017 in Budapest. On top of this, the study was also presented and discussed with stakeholders during several conferences (e.g., Madrid Forum October 2017) and also during individual meetings.

3. ASSESSMENT OF THE CURRENT FUNCTIONING OF THE EU GAS WHOLESALE MARKET

This Chapter assesses the dynamics that have recently shaped the performance of the EU gas wholesale market. Since price convergence is perhaps the most important indicator of an integrated and well-functioning gas market, we focus our analysis on within-EU wholesale price differences and on identifying key explanations for remaining price differences.

Chapter 3.1 sets the seen by presenting wholesale gas price levels and price differences for the period 2015-2016 based on data published in the EU Quarterly reports on European Gas Markets. The next two chapters describe the relationship between wholesale prices and upstream market concentration at the EU level (3.2) and across Member States (3.3). Chapters 3.4 to 3.6 discuss the most important barriers to trade or market inefficiencies and their relevance to explain the wholesale price differences: the lack of interconnectors (3.4), the current level and structure of cross-border tariffs (3.5), physical and contractual congestion and customer market foreclosure (3.6). Chapter 3.7 concludes on the analysis of wholesale price differences. Chapter 3.8 provides a forward-looking assessment of the role long-term contracts might play in the future on the IGM. Market foreclosure risk by long-term capacity contracts is in the focus of this Chapter that also includes a case analysis of the March 2016 Prisma auction to illustrate such risks. We also provide a brief comment on the problems caused to the market integration process by local specifics in implementing third package rules (3.9), although we think these issues could and should be handled as part of the Third Regulatory Package implementation process. We close the Chapter with suggestions on how improved TSO cooperation could better help to move the market integration process ahead (3.10).

Our in-depth analysis of 2015-16 wholesale price differences within the EU suggests that the European gas market is not yet a fully integrated single market. While the wholesale gas markets of Denmark, Belgium, the United Kingdom, the Netherlands and Germany create a single price zone, the presence of different trade barriers (cross border tariffs; the lack of interconnectors; physical and contractual congestion) as well as differences in local market structure and exposure to upstream suppliers can explain remaining wholesale price differences.

While European customers with access to the most liquid markets and best priced gas paid 7 EUR/MWh over US prices in 2016, customers in the highest priced Finland paid an extra 6 EUR/MWh on that – a price almost triple of Henry Hub.

The price premium that EU wholesale customers have been paying over US prices in the last decade is largely related to the concentrated nature of the EU gas upstream sector, including extra-EU gas suppliers. The debate about the efficiency of the IGM and remaining potentials to improve it is to be evaluated in this broader context.

We also found a causal relationship between Member State level market concentration and wholesale price level, as a high concentration level leads to higher prices. This relationship is most demonstrative if we compare the North-Western countries with the rather isolated Eastern Member States.

National entry–exit systems with charging full cost for gas transit plus auction premium at intra-EU IPs or applying distortive IP tariffs at certain borders enhance market segmentation rather than market integration. The present structure of cross-border gas transmission tariff system and the related tariff 'pancaking' (accumulation of tariffs to be paid by traders when shipping gas through several borders) have an effect of trade barriers within the EU. Pancaking hits new entrants to cross-border trading, limits the use of alternative gas transportation routes so some routes may not be efficiently used and creates a barrier to develop more efficient cross-border balancing. We expect these problems to become more visible as LTC capacity bookings start expiring from 2019 onward.

Unless any regulatory or significant tariff change comes, we expect market segmentation to increase within the EU in the future. The current situation of overbooked transmission capacity by long-term contracts will change between 2020 and 2030. The transformation of the capacity market from long to short term may cause a more profound price segmentation of the IGM with greater location spreads compared to today, which will fully reflect short-term transmission tariffs and physical flow direction. This may happen because new capacity bookings after expired LTCs will come at an actual, instead of a sunk cost to traders.

Long-term capacity bookings and physical delivery to the target country by extra-EU producers create inefficiencies in the redistribution of the contracted gas volumes according to short term supply – demand conditions within Europe. To mitigate the welfare loss caused by the limited tradability of the gas along the long term contracted route, capacity bookings on existing infrastructure should be largely confined to short term (yearly or shorter) products.

At the same time, we expect the appetite of extra-EU suppliers for long-term capacity bookings to remain intense and the related risk of market foreclosure apparent. The first large scale application of CAM NC on capacity auction with new capacities provided a stark example of potential market foreclosure by long-term capacity bookings by an extra-EU producer.

3.1 Current wholesale price differences in the EU and potential explanations

There is a broad agreement that price convergence is one of the most important signs of an integrated and well-functioning gas market. High-level price convergence signals that there are no serious barriers to trade which would prevent market participants from buying gas where it is cheaper and selling it where it is more expensive. Therefore, we put the explanation of wholesale price differences to the centre of our analysis of IGM functioning.

3.1.1 Wholesale price differences and price zones

Figure 2 presents wholesale price levels in 22 EU countries[13] for the period 2015-2016 based on data published in the EU Quarterly reports on European Gas Markets. The Quarterly reports display basically two types of price data: hub prices and import prices. The latter can be estimated border prices for pipeline gas which are deemed to be representative of long-term contracts, and LNG landed prices. In cases of countries where different import prices are published in the Quarterly reports, we calculated an average import price using import volumes data from the BP Statistical Review and Eurostat as weights. Hub prices were used as the complementary price for the volumes with unavailable import price data.[14] In cases of countries, where both hub price and import price(s) are available, for calculating across-the-border price differences, we used the two types of prices separately (see below), but for presenting price levels, we used the simple average of the hub prices and the estimated average import prices.[15] In cases of countries with only one price (hub or LTC), we used that value, regardless of the volume associated

[13] The Quarterly Reports do not publish prices for the following Member States: Croatia, Cyprus, Ireland, Luxemburg, Malta and Portugal.

[14] In the case of Belgium and France.

[15] In the case of Belgium, France, Germany, Italy and the United Kingdom.

with that source.[16] Yearly and two-year average prices are consumption-weighted averages.

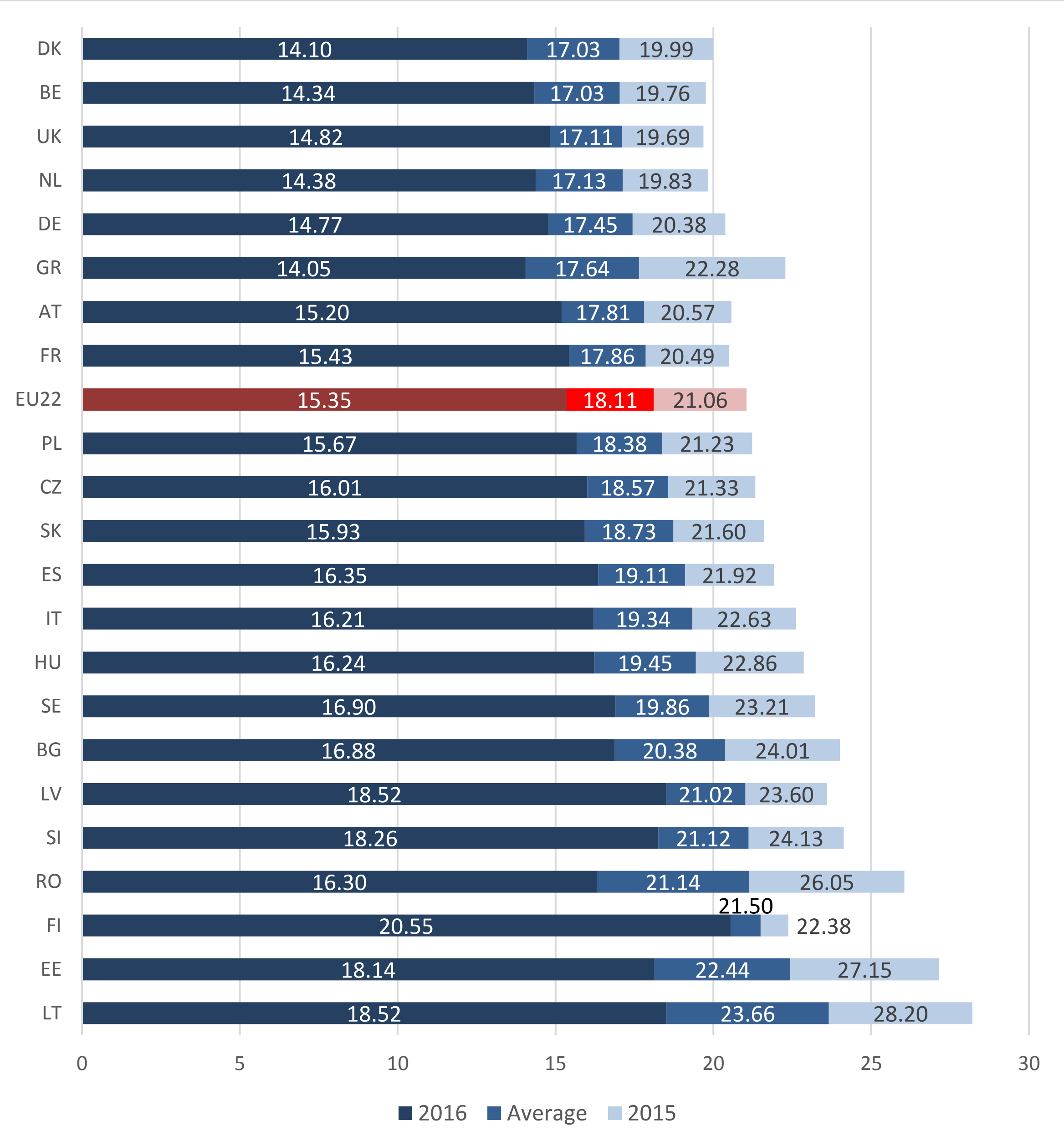

Figure 2: Gas wholesale price levels in the EU (EUR/MWh)[17]

Source: REKK analysis based on EU Quarterly Reports on European Gas Markets

[16] The scarcity of available data raises a limited problem in cases where one importer has a quasi-monopoly status but leads to inaccurate estimates in cases where other sources are also available in great volumes. E. g. the inland production covers most of the consumption in Romania (97 and 87% in 2015 and 2016 respectively), and therefore the price of the Russian LTC has limited effect on sourcing cost. A similar problem emerges when the Quarterly reports publish prices of liquid hubs with limited traded value compared to the consumption (e.g., for Poland). We note in the following if the possibly inaccurate price data can affect our results.

[17] In the case of Bulgaria, the Quarterly reports publish prices reported by the Bulgarian regulator for the period 2016 Q2 – 2017 Q1, while for the previous and subsequent quarters the price estimates are based on Eurostat data. As significant differences can be observed between the two datasets, we checked the Eurostat data for that period, and decided to use own calculation based on Eurostat data for that period.

Gas wholesale prices dropped in 2016 by 27% on average compared to the previous year, but the reduction varied between 8% and 37% across countries. Although the spread between the cheapest and the most expensive country narrowed from EUR 8.5 to EUR 6.5, in relative terms it widened from 46% to 49%. The average price level differences suggest that the European gas market is not yet a fully integrated single market. However, we can observe that:

- Countries with prices below the average are adjacent North-Western European countries[18] (except for Greece), and the spread within this territory is less than EUR 1 (or 5%) regarding the two-year average prices, and below EUR 0.5 among the five cheapest (core) countries;
- Prices above the average have a EUR 5.3 (or 29%) spread;
- The North-Western countries are followed in the ranking by their Southern and Eastern neighbours[19], with a EUR 1-3 price level difference on the respective border;
- Countries with the highest prices have no direct access to the North-Western region, except for Slovenia (to Austria), and have significant differences even compared to the mid-priced countries or each other.

Based on this first look, the European gas market has a large, considerably integrated part, there are countries with moderated connection to it, and there are countries which can be considered rather isolated.

To have a more precise picture at the level of market integration, across-the-border price differences are calculated at the quarterly level as well, taking the average of the absolute price differences from every quarter.[20] We assume neighbouring countries are not integrated enough to belong to a single price zone, if the average prices are similar only for a longer period, but the quarterly prices show significant differences (including the case when similar averages are due to the presence of positive and negative differences over the longer period[21]).

Figure 3 summarises the remaining wholesale gas price differences across neighbouring EU countries for the period 2015 Q1 - 2016 Q4. Only borders with existing interconnectors are analysed (26 borders, 9 of which are considered unidirectional[22]). Price zones are defined based on average quarterly across-the-border price differences, and not on

[18] Denmark, Belgium, the United Kingdom, the Netherlands, Germany, Austria and France.

[19] Poland, the Czech Republic, Slovakia, Spain, Italy, Hungary and Sweden.

[20] Using the same type of price data from the compared countries (making hub price to hub price and import price to import price comparisons), if possible. As only hub price is available for the Netherlands, Denmark and Austria, the above-mentioned North-Western countries are compared to each other based on hub prices. However, comparisons are made based on import prices on the German-Czech and on the French-Spanish borders (and obviously on the Central and Eastern European borders, where only import prices are available). In some cases, hub price to import price comparison had to be made because of the availability of data (e.g., on the Austrian-Slovenian and Czech-Polish borders). Therefore, the availability of data leads to even smaller price differences in the North-Western region, because hub-to-hub price correlations are generally higher than import-to-import or hub-to-import price correlations. However, we argue that the sufficiently liquid hubs send the right price signals, so the results for the North-Western region are sufficiently accurate. Accuracy issues are more likely in the case of import prices, especially when only the price of one source is available from many.

[21] If one country is cheaper in one period than its neighbour, but more expensive in another period, the average prices for a longer period can be very similar. The level of correlation can be a sign of such price diversion. As a result of global price trends and other common external factors, correlation is high in general terms (>0.7) in almost any relation (including the non-neighbours, e.g., Spain/Estonia), and even higher (>0.8) in the case of neighbours. Price correlations are almost perfect within a price zone (>0.99 in most cases).

[22] Based on factual non-existence, insignificant capacity or lack of administrative permission.

average price level differences. However, price levels within the price zones are also indicated on the figure.

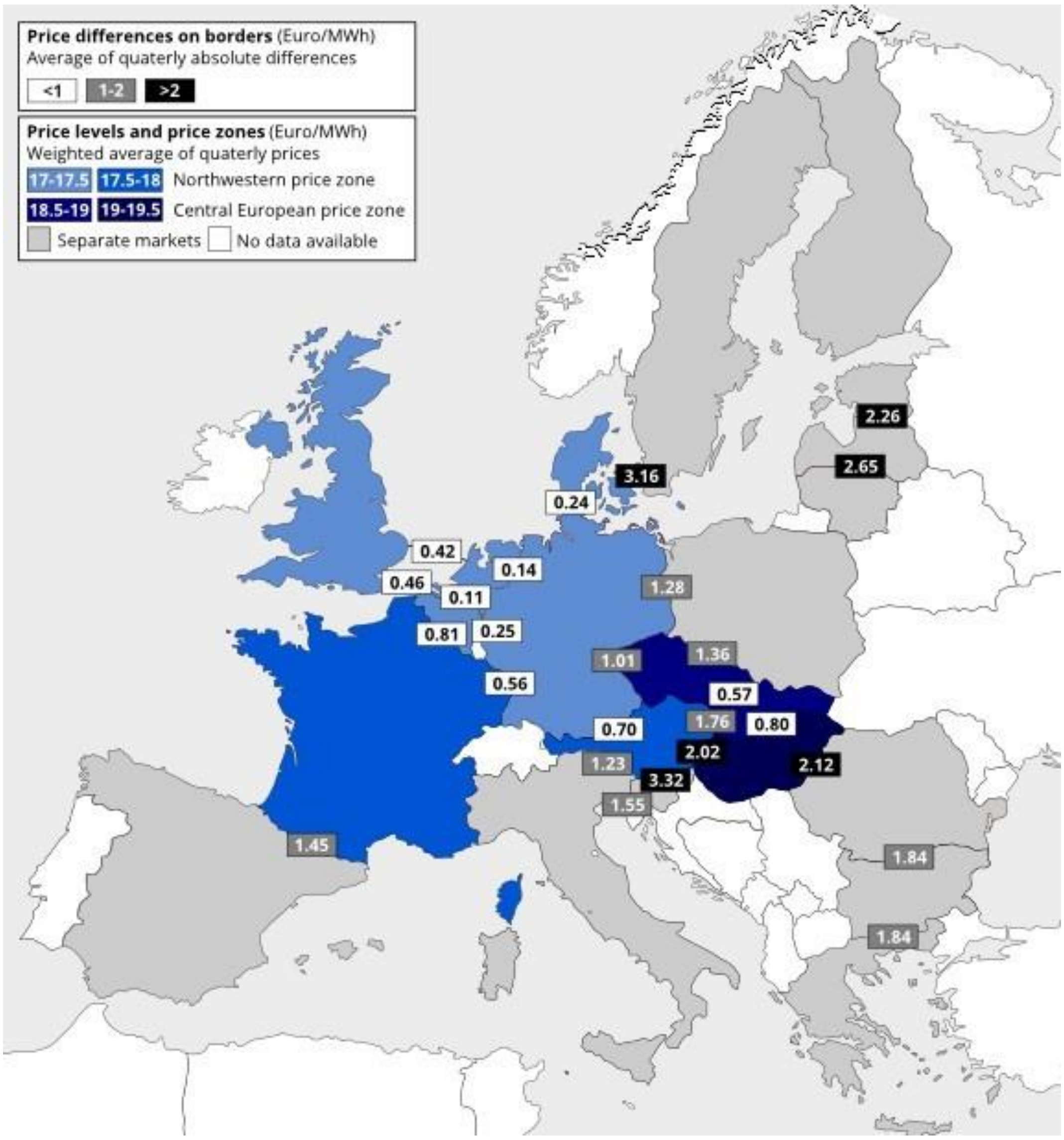

Figure 3: Gas wholesale price differences and illustrative price zones within the EU (2015-2016), without correction for cross-border tariffs

Source: REKK analysis based on EU Quarterly Reports on European Gas Markets

The results confirm the existence and the borders of the North-Western price zone, as across-the-border price differences are smaller than EUR 0.5 within the core of the region, and EUR 0.5 to 1 on the borders with France and Austria.[23] The price differences on the outer borders of the price zone exceed EUR 1. According to our analysis, the Eastern and Southern borders of Austria play a major role in maintaining price differences in the EU, especially towards Hungary and Slovenia.[24]

[23] Price correlations are in the 0.994-1.000 range within the core, and in the 0.989-0.998 range on the borders with France and Austria.

[24] Hub-to-import price comparison had to be made on the mentioned borders of Austria.

The price differences are also below EUR 1 on the Czech-Slovak and on the Slovak-Hungarian borders, indicating the presence of a Central European price zone. Although the Czech-German across-the-border price difference (1.01) raises the possibility for the Czech Republic to merge with the North-Western price zone, the country is clearly closer to Slovakia and Hungary, which are obviously not in one price zone with Austria.[25]

Poland would belong to the Central European price zone based on the two-year average price levels, but average absolute across-the-border price differences indicates barriers to trade on the Czech-Polish border. The quarterly price differences exceed EUR 1 on 6 occasions (out of 8), 2 of which exceed EUR 2. The average price level difference is small on that border because the direction of the difference changed over the period (with the Czech Republic being cheaper 5 times out of 8). We argue that these kinds of diverse price trends are signs of lower level market integration.[26]

In sum, we conclude that:

- The wholesale gas markets of the five cheapest countries (Denmark, Belgium, the United Kingdom, the Netherlands, Germany) are fully integrated, and can be considered together as a single market;
- The somewhat costlier French and Austrian markets can be classified as second line members of the North-Western price zone, whose integration is not perfect;
- Within the mid-priced Southern/Eastern belt around the North-Western price zone, the Czech, the Slovak and the Hungarian markets shows signs of higher level integration (with each other)[27];
- Other mid- or high-priced markets (e. g. Italy, Slovenia, Poland, the Baltic states) are not integrated enough with any neighbouring market to classify them in the same price zone, indicating significant barriers to trade on their borders.

In the following, we first compare the current European gas wholesale price level and development to that of the US.[28] We comment on the consequences of the EU's high and growing import dependence and simultaneous high upstream market concentration, though we understand that these largely exogenous conditions that are difficult to directly

[25] The average price difference in the CZ/HU relation (0.95) is smaller than in the CZ/DE relation, while correlation is higher (CZ/HU: 0.992, CZ/DE: 0.952).

We note that defining distinct price zones based on bilateral price differences are difficult in general, because if one country has small price differences towards two different neighbouring countries, it does not mean that the price difference between those two neighbours is small as well (e.g., in the case when price increases or decreases from country to country by a small amount, but the last country is also adjacent to the first. Thus, defining price zones has a rather illustrative role, and the borders of the price zones are not impassable.

[26] Price correlation is 0.890 on that border, which is significantly lower than in the above-mentioned cases (the fifth lowest correlation among 26 borders). We note that this result can be associated with the difference in available price data (Russian LTC import price for the Czech Republic and hub price for Poland). We also note that the moderated traded volume on the Polish hub raises the question whether the hub price is a good proxy for wholesale/import prices. The German-Polish border shows slightly lower across-the-border price difference and significantly higher correlation (0.995), which suggests that the Polish gas market is more integrated with the German market than with the Czech.

[27] Although this result can be associated probably more with the similarity of accessible external import sources than with the high level of trade with each other, price discrimination (by the dominant supplier) is possibly prevented by the sufficient level of market integration (the existence of the secondary market). The SK-HU interconnector can be a good example for that: The commercial usage started in July 2015. The price difference was EUR 3.14 in 2015 Q1 and EUR 1.25 in 2015 Q2, which decreased to EUR 0.1 (2016 Q1) and EUR 0.52 (2016 Q2), despite the very low utilisation rate. The average across-the-border price difference was EUR 1.14 in 2015, but only EUR 0.47 in 2016 on that border. (The case is the same in the CZ/HU relation, the difference dropped from EUR 1.42 to EUR 0.48.)

[28] It is the US gas price benchmark that has the most significant impact on the competitiveness of European large industrial gas customers and their investment location decisions.

address by gas sector specific EU regulatory measures. Still we think that the efficiency of the IGM's internal functioning and remaining potentials to improve it is to be evaluated in this broader context.

Next, we go through the potential explanations for the remaining price differences within the EU. We start with assessing the impact of upstream market concentration on wholesale prices across Member States. Then we examine the following barriers to trade that we think contribute to market integration problems and related increase in upstream market concentration: (i) physical constraints to infrastructure access, (ii) the current level and structure of cross-border tariffs, (iii), regulatory and contractual constraints to infrastructure access and (iv) local specifics in implementing the Third Energy Package rules.

3.2 EU level upstream market concentration

Despite improvements in IGM functioning, even those EU wholesale customers from the North-Western price zone with access to the most liquid market place of the EU have been paying significant price premium over US prices in the last decade (see Figure 4).

Wholesale gas price development in the US and the EU was strongly correlated with each other and with the oil price before 2009. Since then, however, prices in the two regions diverged significantly. While the US price has decoupled from oil price development due to increased supply competition[29] and related spread of GoG pricing, the same process has been slower in the EU.[30] Even after a major narrowing of the EU-US price difference, due mostly to the collapse of the oil price after 2014, EU gas wholesale prices were about the double of that of the US in 2016 – despite significantly higher gas production costs in the US compared to that of in Russia and most probably also in Norway[31].

[29] The shale gas revolution as well as the limited LNG export capacity of the US have largely contributed to this development.

[30] The predominantly oil-indexed pricing scheme of legacy commodity LTCs in the EU can partly explain this development.

[31] Statement based on REKK estimate using the following World Bank publication on natural gas rents: https://data.worldbank.org/indicator/NY.GDP.NGAS.RT.ZS.
We found no official data publication on gas production costs in Norway.

Figure 4: Gas wholesale price development in the US vs the EU (1996-2016)

Source: BP Statistical Review of World Energy, 2017, IMF Commodity Database

The EU price premium is largely related to the concentrated nature of the EU gas upstream sector, including extra-EU gas suppliers. The primary problem for the future development of the EU's gas market is its high and growing import dependence (over 70% in 2016) and the simultaneous high concentration in supplying its import needs (Figure 5). The market concentration index indicating the product market concentration for extra-EU gas import[32] was 2508 in 2016, indicating significant market power related risks.

This situation is not likely to improve in the future. The EU is developing its competitive internal gas market without the hope of having a truly competitive domestic upstream sector. Domestic gas production is forecasted to decrease 30% by 2030, while the future of non-conventional gas production seems to fade away from the EU.

In 2016, 77% of gas imports to the EU were controlled by three major government-owned companies[33], which supplied the EU predominantly through their pipeline systems, while LNG providers played the role of a competitive edge. Beyond traditional LNG suppliers, the US entered the EU market in 2016, though with marginal volumes (H1 2017 US LNG sales in the EU were 1.2 bcm).

[32] Since the participation of intra-EU gas production in EU cross-border gas trade, and thus its competition with extra-EU imports is very limited, in this Section we restrict the market concentration analysis to extra-EU producers serving residual EU gas demand. The very high and growing gas import dependence of the EU provides further relevance to focus the analysis on imports.

[33] Only two third of Norwegian gas is controlled by Statoil. One third is owned by Petoro (100% owned by the Norwegian State). This gas is sold by Statoil. One third is owned by Statoil (67% owned by the Norwegian State. Listed on the stock exchange in Oslo and New York). One third is owned and sold by other producers like Shell, Engie and DEA.

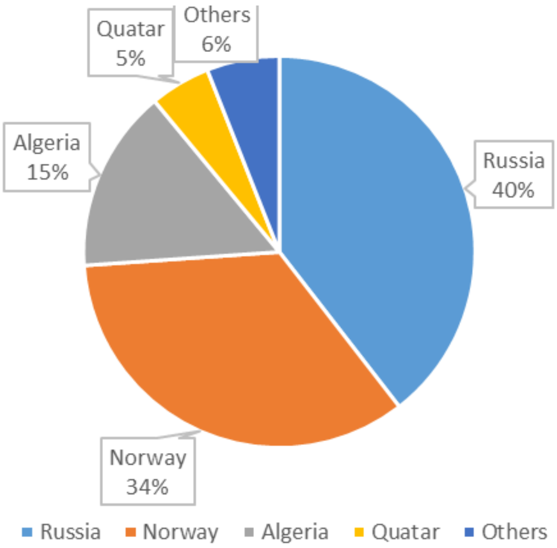

Figure 5: Extra-EU gas import shares by supplying country, 2016

Source: Eurostat

This upstream framework is in sharp contrast to the US gas market where market functioning and wholesale price development relies on an extremely competitive upstream sector.

To illustrate the critical importance of this point from an EU-wide welfare point of view, we investigated the potential impact of a simple but speculative upstream scenario on the EU gas wholesale market.

We estimated the change in the market concentration index for product market concentration for extra-EU gas import assuming gas upstream and export liberalisation in Russia. This scenario would allow three separately owned and competing companies to equally share Gazprom's 2016 export volume instead of keeping Gazprom monopoly. In this scenario, the HHI value drops to 1,468, a value indicating a fully competitive situation on the EU import market. The results of this thought experiment are illustrated in Figure *6*.

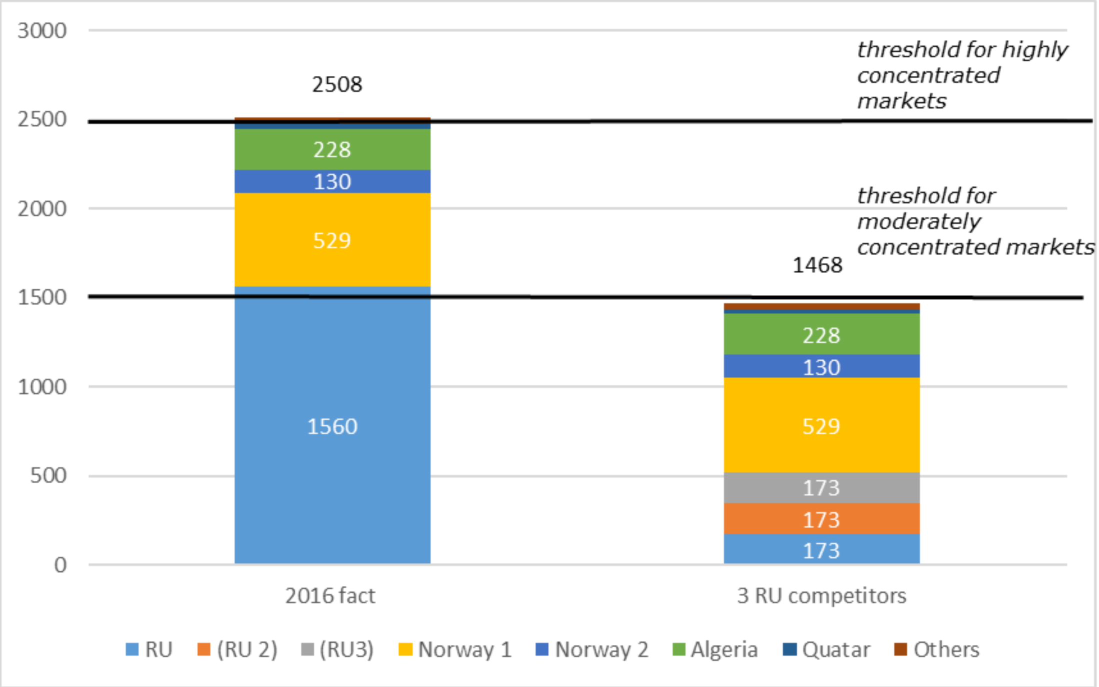

Figure 6: Extra-EU import concentration: Market concentration index scenarios for serving residual EU gas demand (based on 2016 data)

Source: REKK analysis

We assume that a shift in the competitive dynamics of the extra-EU upstream sector like the illustration above could bring significant gas wholesale price reductions and related benefits for EU gas customers. For this reason, we return to further investigate this option in Chapters 6 and 7.

3.2.1 The significance of LNG to foster EU wholesale market competition

Increasing global LNG oversupply as well as large volumes of regasification capacity helps competition to unfold between LNG and pipelined gas in the EU. LNG has the potential to put continuous and significant competitive pressure on dominant pipeline suppliers and deter them from oligopolistic pricing strategies.[34] Low oil prices and increasing LNG – pipeline competition benefited continental EU gas customers by a 30% TTF price decrease in 2016 compared to the previous year. The current strategy of Gazprom to stabilise its market share by keeping LNG away from the EU wherever and until it credibly threatens its position implies a very flexible pricing policy on its side.

Given its outstanding significance for an efficiently operating future EU IGM, obstacles to allowing for a full wholesale market impact of LNG across the EU are to be identified and addressed. There are at least two major obstacles and an additional regulatory issue to address in this regard.

i. Physical evacuation of LNG from certain regions or countries is currently strictly limited. The lack of sufficient pipeline connection between Spain and France, internal congestions in France and the lack of bidirectional capability of French

[34] In a former analysis on the likely impacts of a coming "LNG glut" on the internal gas market REKK (2016) concluded that the doubling of LNG inflow to the EU gas market – due e.g. to lower Asian demand making the EU more attractive to LNG exporters or decreasing LNG costs – could decrease average EU gas wholesale prices by around 2 EUR/MWh.
http://rekk.hu/downloads/projects/The%20prospects%20for%20LNG%20in%20the%20Danube%20Region_discussion_paper_REKK.pdf

interconnectors with Germany and Switzerland limits the availability of about 100 bcm of Portuguese, Spanish and French LNG regasification capacities to the rest of the IGM; on the other hand, due to existing supply and pricing situation such capacity has not been demanded from the rest of the IGM up to now. Greek and Lithuanian LNG regasification assets are mostly serving local market needs and their evacuation options are still missing or limited. Finally, conditions of access to UK LNG regasification assets might change for the worse after Brexit.[35] Table 3 below illustrates that about half of the EU's potentially available LNG regasification assets face evacuation problems. In addition, Brexit might make the access to the UK natural gas market (including its 48 bcm LNG regasification capacity) complicated or expensive. It is Dutch, Belgian, Italian, Polish and part of the French LNG that, if necessary, could physically be evacuated to the rest of the IGM.

Total LNG regas capacity, bcm, 2016	**209,3**
Evacuation constraints	
Spain+Portugal	76,8
France	24,3
Lithuania	4,0
Greece	4,8
UK – depending on Brexit	48,1
Available for remaining 19 MSs + Malta + Cyprus	**51,3**
France	10
Belgium	8,8
Netherlands	12,0
Italy	14,7
Poland	5,0
Rest	0,8

Table 3: The accessibility of EU LNG regasification terminals

Source: REKK analysis

ii. Accessibility of LNG for countries further away from EU LNG entry points is also limited by accumulated cross-border tariffs along necessary transportation routes.

iii. A closer look at the recent performance of the limited, more accessible set of LNG regasification assets mentioned above, exhibits a significant variation in the third party access regime, capacity utilisation and long-term capacity booking levels (see Table 4 below). High tariffs and the high level of long-term capacity bookings at LNG terminals with key locations might limit the access of new upstream LNG suppliers to the EU IGM. Vertical integration between LNG regasification facilities and production and supply businesses might create incentives to foreclose competitors from access to these essential facilities.

[35] Thierry Bros: Brexit's impact on gas markets. January 2017

Terminal name	Country	Nom. Annual Cap. billion m^3(N)/year	Start-up year	TPA regime	Tariff, €/MWh	Peak month utlization 2016	Average Utilisation (2012-2016)	Capacity booked long term 2020
Zeebrugge LNG Terminal	Belgium	8.81	1987	regulated	0.87	15%	19%	100%
Dunkerque LNG Terminal	France	13	2016	exempted	n.a.			77%
Gate terminal, Rotterdam	Netherlands	12	2011	exempted	n.a.	9%	6%	92%
Panigaglia LNG terminal	Italy	3.4	1971	regulated	0.69	29%	9%	0%
Porto Levante LNG terminal	Italy	7.58	2009	hybrid (20% regulated, 80% exempted)	3.16	99%	73%	82%
FSRU OLT Offshore LNG Toscana	Italy	3.75	2013	regulated	3.22	58%	6%	0%
Swinoujscie LNG Terminal	Poland	5	2016	regulated	2.2	50%	36%*	65%

**Average of 2015 and 2016*

Table 4: Main characteristics of continental LNG regasification terminals at non-isolated locations

Source: IEA Gas Trade Flows in Europe

To ensure sufficient access to LNG regasification assets for upstream LNG suppliers and EU midstream market participants, and thus creating continuous and significant competitive pressure on dominant pipeline suppliers to deter them from oligopolistic pricing strategies, the EU could consider at least the following regulatory actions:

- Assisting the completion of missing infrastructure to make the evacuation of LNG from currently isolated regions possible, conditional on a supporting social cost-benefit assessment given these can be costly solutions.[36]
- To eliminate cross-border tariffs to ensure a seamless flow of LNG within the IGM (see the Tariff Reform Scenario in Chapter 6).

Besides LNG, it is a combination of ambitious energy efficiency and renewable support policies that could significantly decrease gas demand, and thus improve gas import competition in the EU.[37] A detailed discussion of this topic is however beyond the scope of our current study.

We conclude that even after a major recent drop, due to decreasing oil prices and improved efficiency in IGM functioning, European wholesale gas prices are still relatively high when compared to the US. The debate about the efficiency of the IGM and remaining potentials to improve it is to be evaluated in this broader context.

Due to its outstanding significance for the future development and performance of the IGM, we develop future sensitivity market scenarios related to LNG availability and cost for Europe and test how the proposed alternative regulatory scenarios developed in Chapter 6 perform under those sensitivities (Chapter 7).

Now we turn to the analysis of wholesale price differences within the EU and barriers to trade that hamper further market integration and wholesale price convergence.

3.3 Member state level upstream market structure and wholesale price differences

While European customers with access to the most liquid markets and best priced gas paid 7 EUR/MWh over US prices in 2016, customers in the highest priced Finland paid an extra 6 EUR/MWh on that – a price almost triple of Henry Hub.

Figure 7 depicts the statistical relationship between the Member State level wholesale price estimates presented in 3.1 and the upstream market concentration levels of the Member States (measured by the Herfindhal-Hirschman Index, HHI) published by ACER[38]. The left

[36] GIPL cost is estimated at EUR 0.5 billion; MIDCAT cost estimate is EUR 3 billion

[37] For a recent analysis on this topic see Selei et al (2017)

[38] The index is calculated at the level of the importing companies

plot presents the original ACER values, countries are coloured according to the price zone they were classified in the analysis in 3.1.[39] The right plot contains only one little modification: the countries that belong to a price zone got a uniform concentration level, which is the lowest concentration level within the respective price zone. The consideration behind this method is that the defined price zones are integrated to such a high extent that it is more consistent to calculate market concentration indices at that level, and while raw data is not available to do that, it is reasonable to assume that such a concentration level cannot be much higher than the lowest level within the price zone.

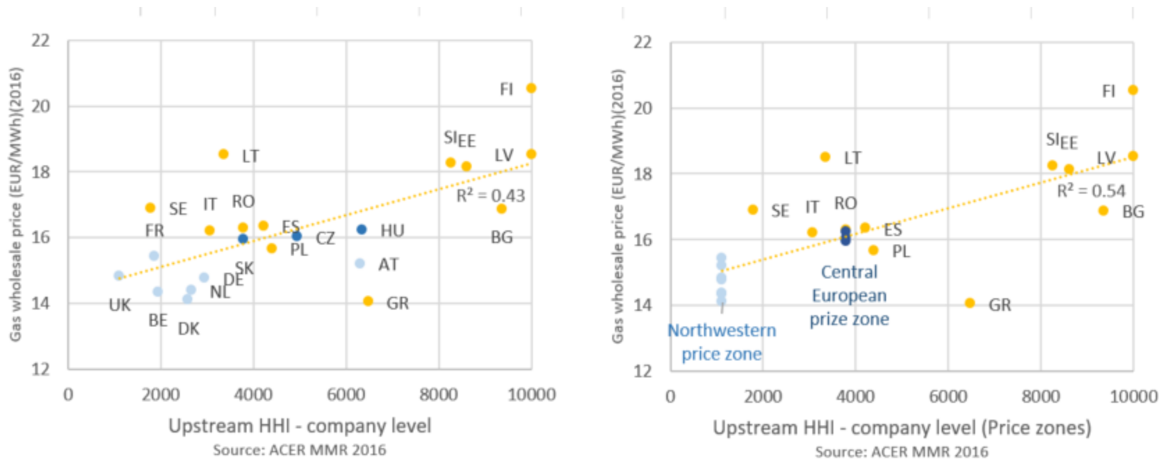

Figure 7: Connection between prices (EUR/MWh) and market structure at upstream level (2016)

Source: REKK analysis based on ACER data and own calculations

The plots reveal significant differences in market concentration levels among countries, from 1,100 (which is generally considered as a sign of a highly competitive market) to 10,000 (the pure monopoly case). Only four countries meet the ACER's related criterion (HHI<2,000), a large group of the markets perform between 2,500 and 5,000 (which is already a high concentration level), while there are five markets with a quasi-monopolistic market structure (over 8,000). Therefore, it is clear that if these markets are separated by barriers to trade, then significant price differences can emerge.

The plots suggest there is a causal relationship between market structure and price level (which is in line with economic theory), as a high concentration level leads to higher prices.[40] This relationship is demonstrative if we compare the North-Western countries (light blue dots) with the rather isolated Eastern states (in the top right corner). However, the connection between market concentration and price level is less clear in some cases, as prices are too low or too high in comparison with similarly concentrated markets.

Sweden and Lithuania are well above the trend line, which means that these countries are more expensive than the market concentration levels would indicate. On the other hand, Greece and some countries from the North-Western price zone (especially Austria) perform much better as they are well below the trend line.

An explanation for the case of Austria is suggested by the right plot. Since the Austrian gas market is not fully but sufficiently integrated into the North-Western markets, the high HHI can be misleading. Taking the lowest HHI from the price zone gives a better fit for

[39] Light blue: North-Western price zone; dark blue: Central European price zone; orange: Separate markets

[40] The R^2 is 0.43, the correlation is 0.652

most of the participating countries, including Austria, and therefore a somewhat higher statistical relationship.[41]

For the other outlier cases, ACER's number of supply sources statistics provides more clarification. Exporter companies have access partially to the same original sources, so the company level market concentration presumably does not catch the market power problem entirely. Figure 8 presents the number of supply sources in terms of the geographical origin of the gas, and the calculated sourcing cost of the respective country. The right plot summarises the minimum, the median and the maximum prices for a different number of supply sources.

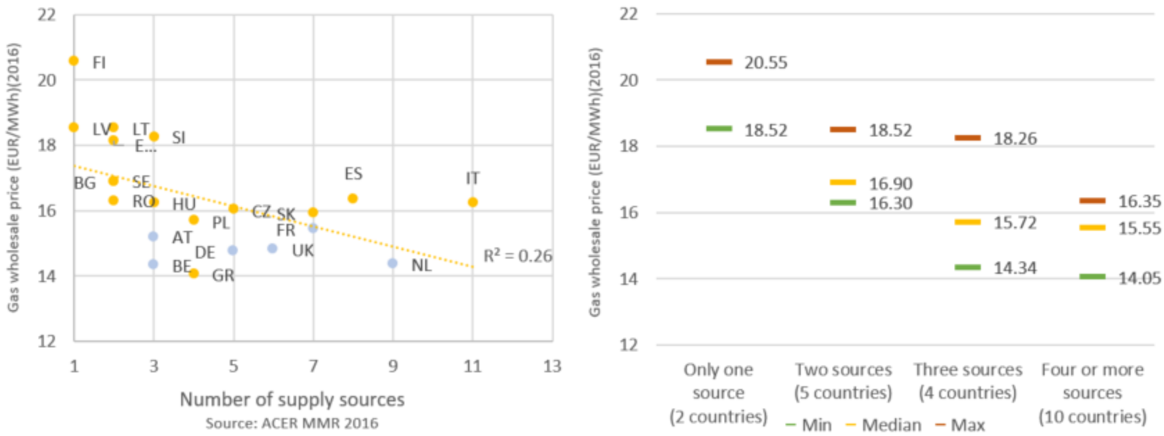

Figure 8: Connection between prices (EUR/MWh) and supply sources (2016)

Source: REKK analysis based on ACER data and own calculations

The left plot suggests that the import diversification can have a significant effect on prices if a country has access to a small number of sources, but after a certain level, more diversification cannot bring lower prices. Therefore, the statistical relationship is not linear but rather logarithmic.[42] According to ACER's related criterion, having three different supply sources is likely to ensure enough diversification. Our conclusion is in line with the ACER recommendation. However, we find that the fourth supply source can have an additional effect, especially regarding the maximum prices. Although the group of countries with four or more sources is more populous, the price spread is much lower in that group than in the group of countries with three sources. The relationship is even stronger if we consider only the sources with a sizeable share.[43]

The plots explain the above-mentioned outliers. Sweden and Lithuania import gas only from two countries (each). In these cases, we can assume that high prices are associated with the insufficient competition between the importer companies from the same country. At the same time, the costs of the importers can have an effect too (the Lithuanian main source is an LNG source, while the cross-border tariff on the Danish-Swedish interconnector is well above the average tariff based on our estimation).

Regarding the low-priced outliers, Austria meets, while Greece outperforms the number of supply sources criteria of ACER. Together with the relatively high company level HHIs, it

[41] The R^2 is 0.54, the correlation is 0.733

[42] The logarithmic trend indicates higher R^2 (0.46)

[43] The number of supply sources with a sizeable share (>10%) does not exceed four in any country and equals to three in the majority of competitive markets. The R^2 is 0.66 in this setting

means that these countries purchase gas from a limited number of export companies, but they are independent from each other regarding their sources.

Finally, we put this analysis in the context of the findings of the EU upstream market concentration analysis presented in Section 3.2. For the sake of comparability, we calculated the extra-EU import concentration indicator (HHI-based) for the countries of the North-Western price zone and for the whole price zone as well.[44]

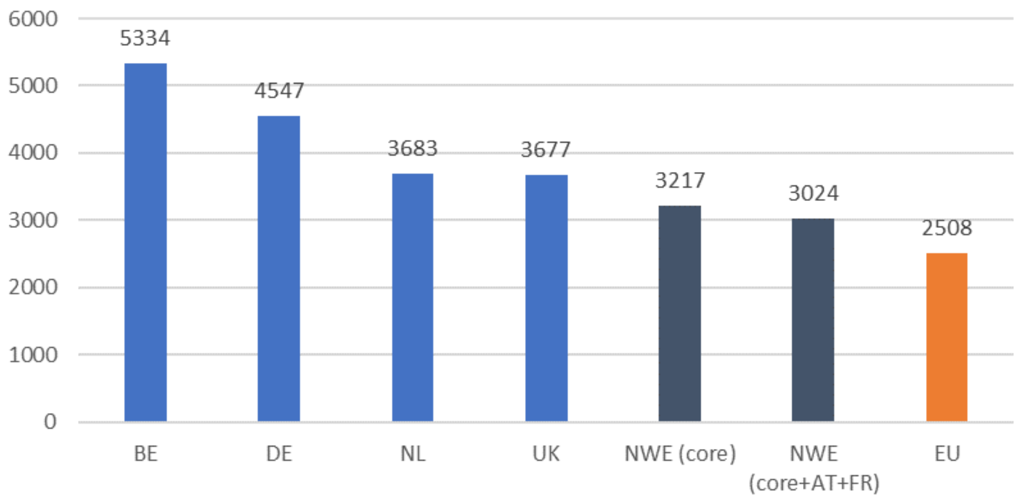

Figure 9: Extra-EU import concentration for North-Western countries and for the North-Western price zone in comparison with the EU level HHI (2016)[45]

Source: REKK analysis based on Eurostat and BP statistical review

Figure 9 demonstrates how market integration can decrease the market concentration at upstream level, as the market concentration indicator is lower at the level of the price zone than at country level.[46] The figure also suggests that even the high EU level market concentration value gives a favourable account of the actual market situation, since at the current level of integration, the extra-EU suppliers have presumably greater market power even on the most integrated and least expensive part of the EU market, than the EU level HHI suggests.

As we stated in the methodology Chapter, we believe that barriers to trade contribute maintaining the diverse supply and demand conditions, especially the market power of the upstream companies in the Member States and thus can largely explain price differences. Therefore, we turn now to barriers to trade analysis. In the following Sections we examine different trade barriers that constrain the effective utilisation of the existing infrastructure. Lack of interconnectors, cross-border tariffs and cases of physical and contractual congestion are identified, and their impacts assessed.

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[44] By excluding intra-EU import at national level, the market concentration index values are obviously higher than in the case when all import sources are taken into account. However, considering intra-EU imports would indicate lower market concentration at national level than at EU level, which could be misleading. The presentation of market concentration index values this way serves illustrative purposes and comparison with the EU level concentration indicator.

[45] Denmark is excluded from the analysis since it does not have a sizeable import. The NWE (core) value is calculated based on the sum of extra-EU import volumes of the four presented countries.

[46] Although it is not necessarily true for every case if countries have imports from the same sources.

3.4 Lack of interconnectors

Table 5 summarises the terrestrial borders between the Member States (included in Table 5) where there are no interconnectors, or the transmission is factually or practically unidirectional, while the price differences indicate a potential need for trade in the other direction (at least in 2 quarters out of 8 in 2015 and 2016). We note that the interconnectors listed below are not definitely required (from a welfare point of view) and/or economically viable.

Country with lower price (occasionally)	**Country with higher price (occasionally)**	**Occurrences of potential need for trade**[47]	**Average price difference** (EUR/MWh)[48]
No interconnector			
France	Italy	8 / 0	1.37
Poland	Lithuania	7 / 1	5.32
Hungary	Slovenia	7 / 1	2.22
Austria	Czech Republic	6 / 2	1.28
Poland	Slovakia	4 / 4	1.70 / 1.67
Unidirectional interconnector (with need for the other direction)			
Greece	Bulgaria	8	1.84
Poland	Czech Republic	3	1.87
Romania	Hungary	2	0.84[49]
United Kingdom	Netherlands	2	0.27

Table 5: Missing interconnectors and directions between Member States and respective price differences (2015-2016)[50]

Source: REKK analysis based on ENTSOG data

Based on our findings above, the France-to-Italy, the Poland-to-Lithuania, the Hungary-to-Slovenia and the Greece-to-Bulgaria connections would provide the most possibilities for trade. Further, the Poland-to-Lithuania pipeline would have the largest role in fostering price convergence.

Nevertheless, the lack of connection explains some of the results regarding the borders of the price zones defined in 3.1.1. Firstly, the insufficient integration of the Czech and Polish markets (noticeable price differences and low correlation) can be justified with the missing Poland-to-Czech Republic and Poland-Slovakia (both directions) interconnectors. Based on that, Poland cannot be considered as a member of the Central European price zone.

[47] The number of quarters when price differences indicate a need for trade from the first country to the second / from the second country to the first (the latter presented only in the 'no interconnector' part where both direction are missing). / The number of quarters when price is lower in the country in the second column (out of 8).

[48] Regarding only the periods when price is lower in the country indicated first. In the case of the Polish-Slovak border, average differences are presented for both sets of periods.

[49] The pipeline exists, but the capacity is negligible, and the transmission in this direction was not possible in 2015-2016 due to a lack of administrative permission. The Romania-to-Hungary direction could be utilised in 2016 Q3 and Q4 (and also in 2017 Q1), when Romanian prices were lower. Taking the significant Romanian production into account, the real wholesale price can be lower, and therefore this direction could be utilised regularly and could foster price convergence. However, the published cross-border tariffs are well above the calculated price differences, and significantly higher than tariffs in other IPs.

[50] Price differences are not indicating a need for gas trade in any quarter in the case of France-to-Belgium, France-to-Germany and Slovenia-to-Italy connections.

Secondly, the price difference between Greece and Bulgaria can be explained by the missing northern direction, since the existing pipeline has a transit role (from Russia through Bulgaria to Greece). In these cases, no further analysis is required to identify barriers to trade.

3.5 Current level and structure of cross-border tariffs

Cross-border transportation costs are the most obvious reasons for across-the-border wholesale price differences, because they limit the price-equaliser effect of trade.

A fundamental design component of the Third Package to foster the accomplishment of the EU internal gas market was the introduction of a regulated entry-exit access regime for transmission assets and services.[51] The principal idea of an entry-exit regime is to expand the geographic scope of the gas market place by partially decoupling gas product trading from the transmission services underlying those transactions. By allowing shippers to book and pay for entry and exit capacities separately, the system allows them to enter their gas to or withdraw it from a local virtual market place (or virtual hub) without having to contract for point-to-point transmission services with the transmission operator. Under this regime, TSOs manage the physical balancing of the market. Regulated, transparent and non-discriminatory entry and exit fees should recover the justified costs of the TSOs to invest, maintain and develop their system.[52]

Since 2010, Member States have gradually introduced the entry-exit regime at a predominantly member-state level.[53] NRAs defined entry and exit points, including cross-border interconnection points (IPs) and occasionally interconnection points between system operators within Member States, and established entry and exit tariffs for them.

While the methodology to set entry/exit tariffs is relatively straightforward, the current practical application of the methodology can seriously distort cross-border gas trading within the EU.

The removal of pancaking in the electricity sector

Essential infrastructure sectors like electricity and telecom also once encountered the pancaking problem as a barrier to cross-border trade.

Electricity sector liberalization and integration started with unclear rules on how to price the transmission of the transited electricity flows that were expected to increase with market integration. The first national solutions for pricing electricity transit during the implementation of the first Directive of 1996 often consisted of border tariffs – an import and an export fee (Merlin, 2002). However, these national policies created a situation where the more national borders a cross-border trade transactions involved, the less attractive that transaction became due to the 'pancaking' of border tariffs over the commodity price of electricity.

As a serious threat to cross-border trade development, the issue of how to move away from border tariffs was high on the EU policy agenda from the first Florence Forum back in 1998. In 2002 ETSO, the European Association of Transmission System Operators, first solved the question of pancaking by building a voluntary multilateral agreement among

[51] The EU Third Package prescribes that tariffs for gas transmission networks must be set separately for every entry and exit point (EC 715/2009, art. 13(1))

[52] For a straightforward summary on the merits and challenges of the entry-exit tariff system in the European context see Hunt (2008).

[53] For a recent review of entry-exit regimes as applied in the Member States and a review of related potential trade barriers see KEMA (2013).

TSOs. The establishment of an Inter-TSO Compensation (ITC) mechanism was meant to compensate TSOs for costs incurred by hosting cross-border flows of electricity on their networks. The ITC Fund together with a Fund distribution scheme was the major component of this agreement. From the beginning the logic of the mechanism was that transiting countries receive money from the Fund in proportion to the additional cost born by transited energy on their networks while net exporting and importing systems contribute to the Fund in proportion to their exports and imports. (Gustaffson and Nilsson, 2009). A year later Regulation EC 1228/2003 outlawed distance-related charges and implemented a transmission pricing system where border tariffs were no longer permitted to be applied by Member States. At the same time, existing long-term contracts ceased to have priority access rights to interconnection capacities. While the debate on how to structure the fairest rules for compensation from the ITC Fund continued for more than a decade after 2002, border tariffs were not there to hinder cross border trading in electricity. Today the only extra cost of exchanging energy across borders is the price of the interconnector transfer capacity. This price is non-zero only for congested capacities.

The tale of tariff border removal in electricity provides at least the following lessons for the future of gas market regulation in the EU. Compensation for the cost of hosting transit flows can be made in a non-transaction based manner, e.g., through the establishment of a specific fund. The removal of border tariffs should not prevent market based capacity allocation of cross border capacities. Finally, the removal of border tariffs does not stop the maintenance of and investment into cross-border capacities, given these activities are strictly regulated and their development is largely based on network planning in the EU.

In the natural gas sector, the problems raised by distortive cross-border tariffs are widely discussed. The replacement of cross-border tariffs by inter-TSO compensation mechanism was already considered in 2009 (KEMA 2009). In the prevailing EU regulation, the problem is addressed by both the market mergers envisioned by the gas target model and by certain provisions of the TAR NC. We believe that both have apparent shortcomings that might justify the investigation of a more radical regulatory approach to cross-border transmission tariffs within the EU.

3.5.1 Cross-border entry/exit transmission tariffs as trade barriers

Figure 10 below summarises comparable August 2017 cross-border entry and exit tariffs on the European gas transmission grid. The highest and the lowest 25% of the IP tariffs (for each IP sum of exit and entry tariffs at the given point in the given direction) are indicated with green and orange boxes, respectively. The tariff calculation methodology is explained in Annex 2.

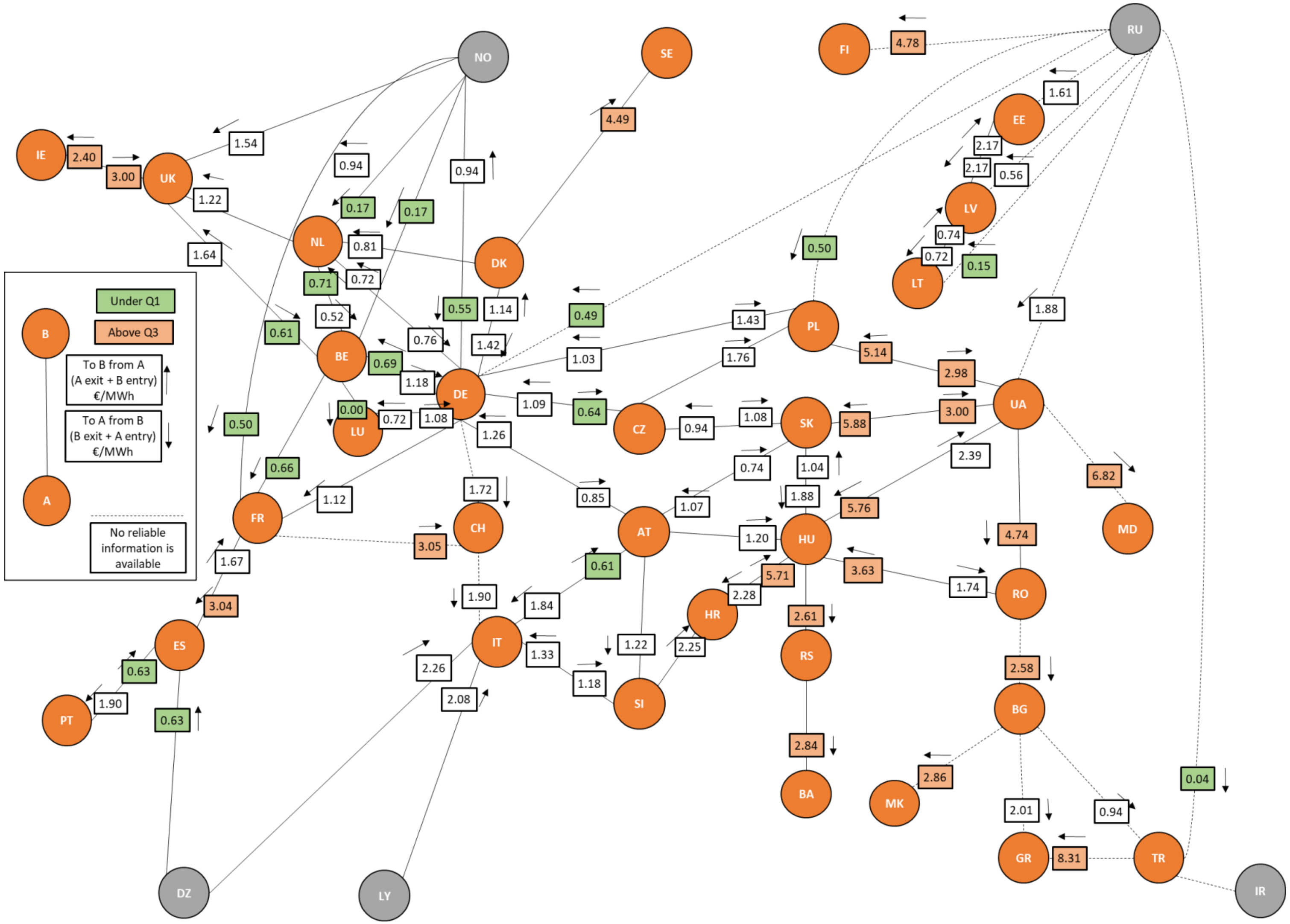


Figure 10: Transmission tariffs in the modelled countries

Source: REKK calculation based on TSO and NRA data, latest information available in August 2017

A closer analysis of individual IP tariffs indicates a more than 20 fold difference for both IP entry and exit tariffs in the EU in the first half of 2017 (see Figure 11).

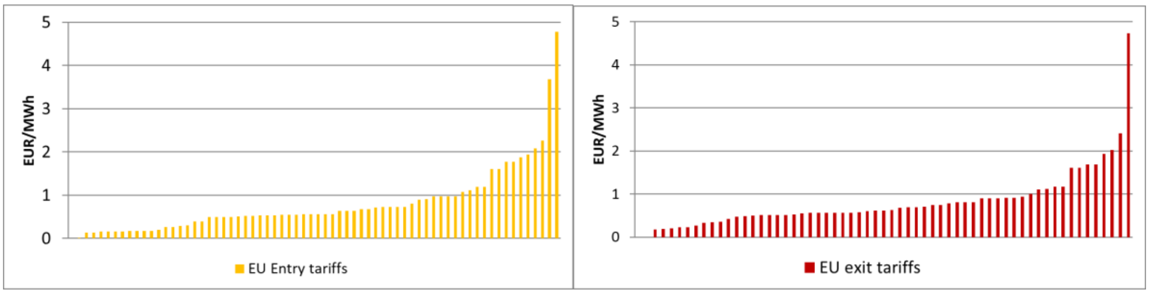
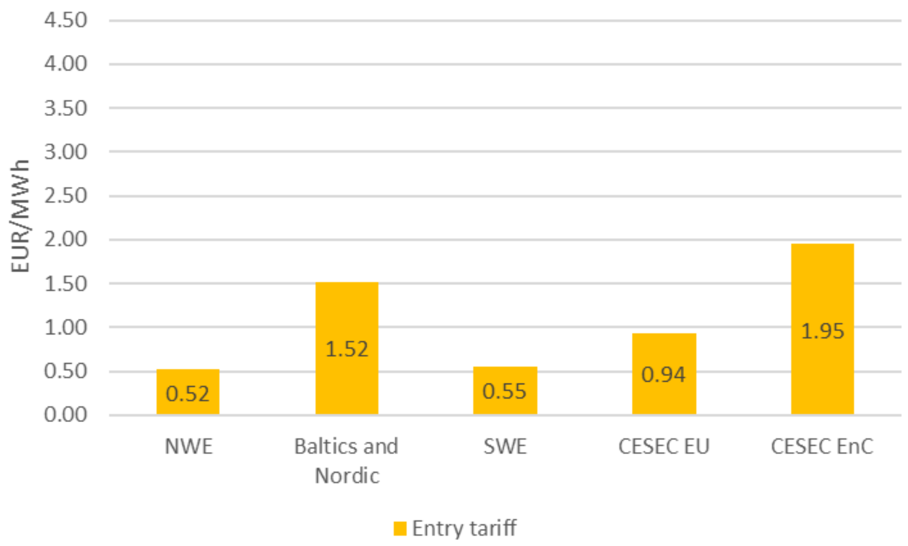


Figure 11: Distribution of IP entry and exit tariffs in the EU, H1 2017

Source: REKK calculation based on TSO and NRA data, latest information available in August 2017

Significant regional differences for both entry and exit tariffs are also present across Europe. In the following Figure 12, average entry and exit tariffs are depicted in different regions of Europe. For every country, the average tariff of all entry points was calculated, and then for every region the average of these values. Then the same calculation was carried out for exit tariffs as well.



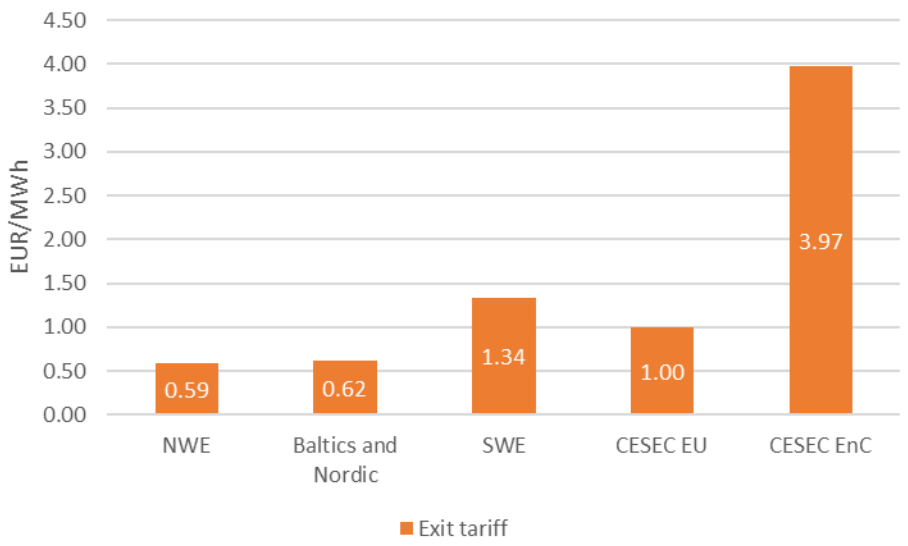


Figure 12: Average level of entry and exit tariffs in five regions, August 2017

*Countries in the different regions: **NWE**: BE, CZ, DE, DK, IE, LU, NL, UK; **Baltics and Nordic**: EE, LT, LV, NO, FI, SE; **SWE**: ES, FR, PT; **CESEC** EU: AT, BG, GR, HR, HU, IT, PL, RO, SI, SK; **CESEC EnC**: BA, MD, MK, RS, UA*

Source: REKK calculation based on TSO and NRA data, latest information available in August 2017

In the Western and Northern part of Europe, cross-border tariffs are much lower than in the South-Eastern part, mainly the CESEC region. Tariffs are particularly high on the borders between the EU and the Energy Community (EnC).

Figure 13 compares average border tariffs (exit+entry) on EU-EU and EU-Energy Community border points between 2015 and 2017, considering only IPs inside the CESEC region. On EU-EU border points tariffs decreased by 15% between 2015 and 2017, while Ukrainian cross-border tariffs significantly increased from 2016.

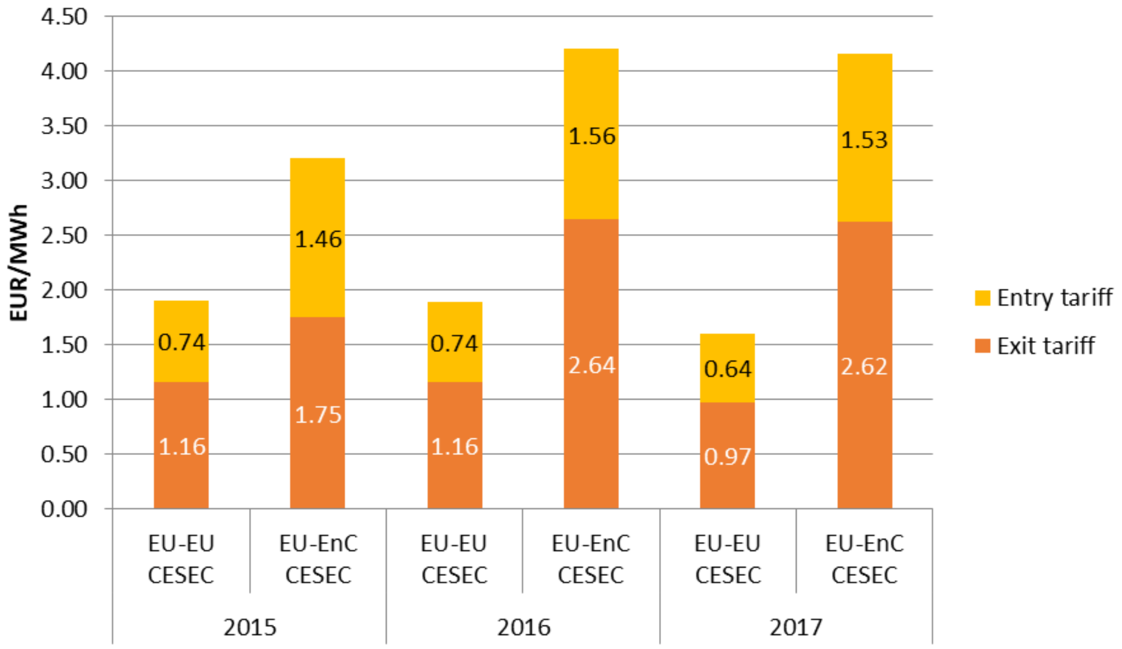


Figure 13: Average border tariffs (exit-entry) on IPs inside the CESEC region, 2015-2017

Source: REKK calculation based on TSO and NRA data, latest information available in August 2017

There might be several reasons behind individual border and regional level tariff differences. These might include the differences in the age and capacity of the pipelines, market functioning, IP related capacity booking and flow levels or tariff distortions (e.g., through cross-subsidisation).

Whatever the reasons are for the very significant cross-border tariff differences, the segmented, national entry – exit systems charging full costs plus congestion fees for gas transits at intra-EU IPs (Hecking, 2015; EWI, 2017) or applying distortive IP tariffs at certain borders (REKK, 2016) are hardly compatible with an EU-wide integrated gas market. The present structure of cross-border gas transmission tariff system and the related tariff 'pancaking' (accumulation of tariffs to be paid by traders when shipping gas through several borders) has an effect of trade barriers within the EU[54], thus we expect that their removal could support further market integration and increased price convergence across the EU.

3.5.2 Inefficiencies caused by cross-border tariff pancaking

At present, pancaking primarily hits new entrants to cross-border trading since they face the full cost of cross-border tariffs. However, for incumbent midstreamers legacy LTC capacity bookings hide the pancaking problem. Since the cost of those bookings is sunk for the LTC holders, cross-border shipping costs are close to zero for them on the relevant IPs. This can explain recent findings by ACER (ACER, 2015; 2017) on market spreads being below transportation costs between relevant hubs in North-West Europe. These findings paint an over-optimistic picture about the efficiency of wholesale market functioning and integration in the EU. We expect the accelerating dismantling of legacy LTCs after 2019 onwards to reveal a more realistic picture about wholesale market functioning. Expiring product LTCs will likely dry up the rest of the excess liquidity

[54] According to Kantor (2017) current cross-border entry/exit tariffs are considered barriers to gas trading by the market participants.

supplied by sales at LTC ToP minima by incumbent midstreamers. Expiring capacity LTCs will recreate locational spreads that better reflect cross-border transportation tariffs. Pancaking will take its full effect at that point.

Pancaking, reflecting the accumulating effect of cross-border transmission tariffs in creating significant wholesale price differences, is present between North-West Europe and Italy. Although Italy is a large and quite liquid market,[55] its wholesale price level is higher than prices in the Northwest or Central European markets. The price spread between the Dutch TTF and the Italian PSV markets is about 2 EUR/MWh, representing about 10% of the wholesale gas price. As a possible solution to reduce this spread, the Italian Ministry of Economic Development proposes, in its new energy strategy, to create a corridor of liquidity, under which the Italian TSO would purchase LT capacity to Northwest Europe, and thus increasing the liquidity of the Italian market.[56] This measure is expected to reduce the above-mentioned price spread. The size of the Italian market represents an average of 685 TWh for 2010 and 2016. Thus, the elimination of the spread would (ceteris paribus) bring an additional EUR 1.4 billion annual cost saving for Italian customers. More information relating to this measure is presented in the box below.

Italian liquidity corridor

In May 2017, the Italian Government published its Energy Strategy 2017. The strategy includes a Section on the so-called liquidity corridor, namely a proposal for reducing the price spread between the Dutch virtual trading point TTF and the Italian virtual trading point PSV. The price difference between these two trading points has stabilized at around 2 EUR/MWh. This difference is rather high compared to other more developed markets. For example, the price spread between the TTF and the German virtual trading point NCG is between 0.2 and 0.3 EUR/MWh for forward transactions.

One of the potentially considered proposals is that the Italian company SNAM (TSO in Italy) buys in its own name the long-term transmission capacity between TTF and PSV and between NCG and PSV, possibly also between PEG Nord (France) and PSV, which is expected to bring a significant price reduction by at least half of the spread.

The Italian proposal is reacting to the persistent location spread caused by tariff pancaking and also to contractual congestion at the German – Swiss border. While an alternative route via Tarvisio is, based on the last ACER monitoring report on Contractual Congestion, not congested from the side of Austria, hence partial alternative physical flow via this interconnection point could be possible[57], this route proves to be costlier due to cross-border tariffs along this route.

The current deployment of cross-border transmission tariffs also limits the use of alternative gas transportation routes so that some routes may not be efficiently used. This creates an important inefficiency in the use of the existing EU gas transmission

[55] See e.g., *European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration* by The Oxford Institute for Energy Studies (May 2017) https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/05/European-traded-gas-hubs-an-updated-analysis-on-liquidity-maturity-and-barriers-to-market-integration-OIES-Energy-Insight.pdf

[56] https://www.argusmedia.com/~/media/files/pdfs/white-paper/italian-energy-strategy-white-paper.pdf?la=en

[57] We are aware that contractual congestion was also reported for the German IPs of Steinitz and Oberkappel.

system since some congestion may be caused or accentuated by the existing tariff structure.

The following box is an illustration of how current cross-border tariffs can increase congestion related problems. It compares the cost of using two alternative routes to ship gas from Germany to Austria. Since the route with the larger pipeline capacity is priced at higher (pre-auction) tariffs, flows are motivated via the route with the lower capacity pipeline, adding to congestion problems at the German – Austrian border (Oberkappel).

Comparison of the cost of competing routes for the transportation of gas from Germany to the Austrian virtual trading point via the Czech Republic

The first route runs from Brandov/Hora Sv. Kateřiny (HsK) (the cross-border interconnection point between OPAL and Gazelle pipelines) via Waidhaus (the interconnection point between Gazelle and MEGAL pipelines) to Oberkappel (the interconnection point between MEGAL pipeline and GCA). The MEGAL route's cost is calculated on the basis of both TSOs' (OGE, GRTD) entry tariffs.

The second route runs from the OPAL gas pipeline across HsK via the Czech Republic to a cross-border point Lanžhot and then via Slovakia to the Baumgarten cross-border point.

Route costs are compared in EUR/MWh and the assumed capacity utilisation level is 85%. This utilisation level approximately corresponds to the actual utilisation level of the two Austrian entry IPs. There are two unit prices for the first route due to different OGE and GRTD pricelist tariffs. We did not consider the actual capacity booking options and only considered the tariffs for 2017 and the fact that the physical gas flow is possible.

Both routes are illustrated and quantified on the following picture.

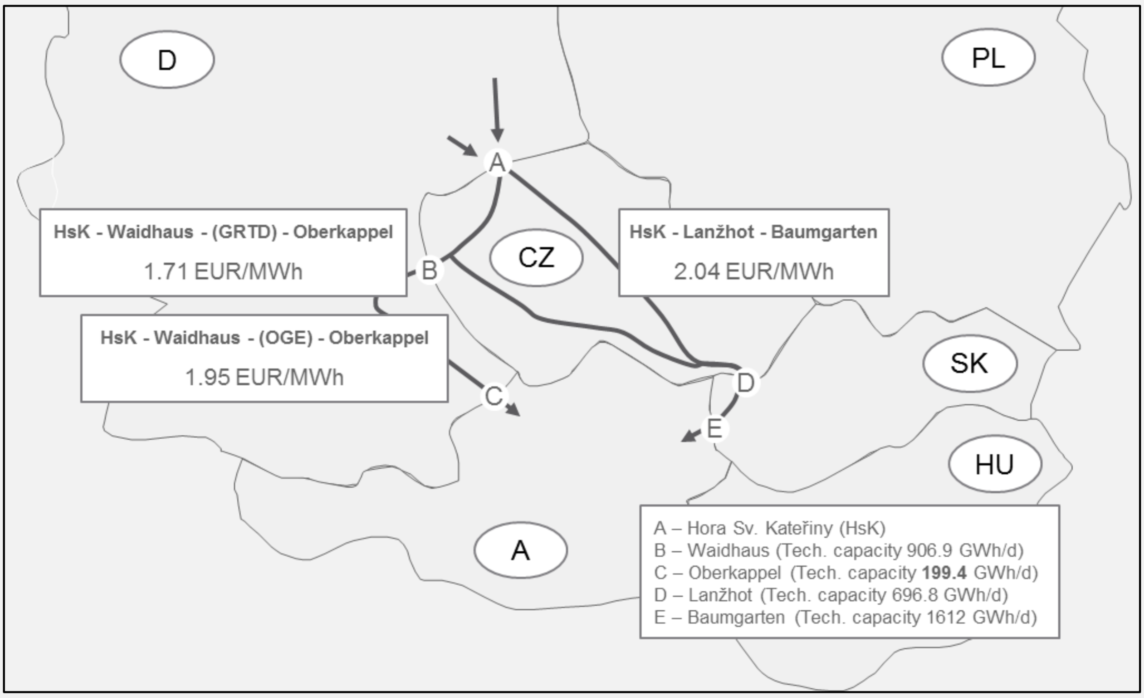


Figure 14: Cost of competing routes for the transportation of gas

Source: EY based on data from TSOs and/or National regulatory authorities

Current IP transmission tariffs limit the availability of flexibility services across the borders. An important parameter of gas supply is its flexibility; that is how quickly and at what cost it can cover unexpected demand or supply fluctuations. The flexibility need of a market can be supplied from domestic sources (storage, production flexibility or line-pack) or by importing it from other zones. Current flexibility prices are low and many zones experience underground gas storage abundance. An increased use of gas-fired power plants to balance the production of intermittent renewable producers could increase the need for short-term gas flexibility. Nevertheless, today it is relatively expensive to transfer this flexibility to the zone where it is needed, precisely because of the size and structure of cross-border tariffs.

We have analysed the current cost of importing/exporting daily flexibility from one EU market zone to another under the current tariff system to assess if a tariff reduction or its complete elimination will have a material impact on flexibility sourcing. Since day-ahead and within day tariffs are different in many countries and further depend on the flow direction (import/export), the possibility and cost of day-to-day balancing through the spot market for a trader in different zones differs across markets. We found that, for daily balancing, the import/export of flexibility is more expensive than the cost of providing it by using, e.g., local storage. Our conclusion is that elimination or reduction of transmission tariffs would foster flexibility transactions across zones.

The current practice of short-term capacity price setting creates a barrier to developing more efficient cross-border balancing. Currently, the entire system is set to reserve annual capacities and shorter periods are usually priced more expensively. Generally, day-ahead and within day capacities are the most expensive product (in unit price) for traders in the current system. Even in the Netherlands, the most liquid market in the EU, short-term capacity is used the least among its available capacity tenors due to its excessive cost. Also, in other gas wholesale markets, short-term capacity is only used as a last resort product when no other tools are available. The opinion is based on an inquiry carried out between market participants, summarized in the Kantor study (2017). More information relating to short-term tariffs is presented in the box below.

Short-term capacity in the Netherlands and Poland

In this case, we compare the methods of calculating short-term and long-term tariffs. Firstly, short-term tariffs are generally less favourable than long-term tariffs (one-year) from which they are derived. Secondly, monthly tariffs as well as the daily tariffs may vary considerably between TSOs. To illustrate this, we present below the monthly tariffs applied by Gasunie Transport Services (the Netherlands) and GAZ-SYSTEM S.A. (Poland) using multipliers.

The short-term tariffs (periods of less than 12 months) are calculated using time-related factors such as monthly factors and daily factors. They are calculated in the following manner: monthly tariff = monthly factor * yearly tariff; daily tariff = daily factor * monthly factor * yearly tariff. In both countries, the monthly factor also depends on the particular month in case of forward flow. The aim is to show that the use of short-term contracts (shorter than a whole gas year) is more expensive than the annual capacity across the EU gas market.

Another difference is the use of daily contracts, which, when added up to 30 days, can be more expensive than monthly contracts. The Dutch daily factor equals 1/30 of the relevant monthly tariff, while the daily factor in Poland is equal to 1/20 of the relevant monthly tariff.

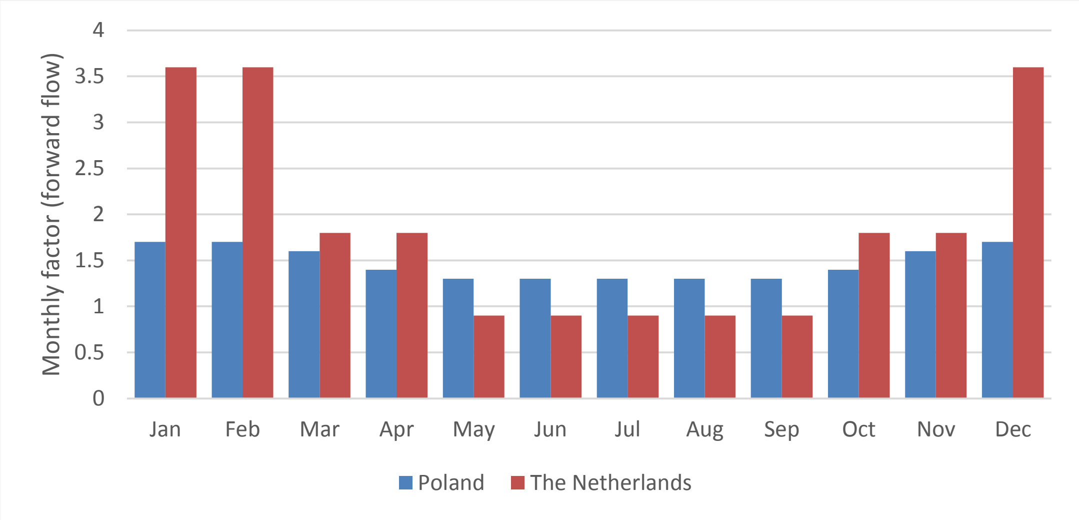


Figure 15: Short-term capacity in the Netherlands and Poland

Source: EY based on Gasunie Transport Services[58] and GAZ-SYSTEM S.A.[59]

If, e.g., capacity is booked for the month of January, then, in the Netherlands, it will be more expensive than the annual equivalent tariff, using the factor of 3.6 (i.e., twice as high as the Polish one). The same method will apply for the daily capacity. The resulting cost for one month as the sum of all individual days is equivalent to the cost of monthly factor in Netherlands[60] (i.e., the daily factor equals 1/30 of the monthly factor). In Poland, on the other hand, the monthly capacity will cost 70% more than the yearly capacity, with an additional 50% cost increase for daily bookings (i.e., the daily factor equals 1/20 of the monthly factor).

From the example data on short-term capacity pricing, it is clear that booking of short-term capacity is at a disadvantage against long-term capacities, even if we account for lower average expected use of long-term capacities. If we assume that a reasonable load factor for long-term capacity is around 80% to 85%, while short-term products are used entirely (100%), a maximum short-term factor of around 1.2 would be appropriate. We understand that it is more convenient for TSOs to sell capacity for the long-term (due to revenue planning, physical flow planning, simpler administration). NRAs may also prefer this solution owing to likely lower actual revenues volatility. High short-term tariffs may, however, further increase the location spreads once the current LTCs expire and no more sunk capacity exists as they will represent an opportunity cost of the transportation between zones.

3.5.3 Cross-border tariff adjusted wholesale price differences

To include cross-border tariffs into our explanation for 2015-16 wholesale price differences, we adjusted our estimated across-the-border wholesale price difference data with cross-border tariffs calculated originally for EGMM modelling purposes (see Figure 10). This tariff does not include congestion fees, whose feature allows us to

[58] https://www.gasunietransportservices.nl/en/shippers/terms-and-conditions/tariff-information

[59] http://en.gaz-system.pl/fileadmin/pliki/taryfa/en/Taryfa_GAZ-SYSTEM_nr_10_EN.pdf

[60] The difference caused by the number of days in January (31 days) is disregarded.

examine the effects of the "simple" transportation costs and those of the possible congestions separately on wholesale price differences.

Tariff adjusted price differences are calculated also at a quarterly level, subtracting the tariff of the relevant direction (from the cheaper to the more expensive country) from the wholesale prices. This difference has a negative value on several occasions, indicating cases for wholesale price differences being below transportation cost. This situation can be the result of different underlying reasons, e.g., similar supply and demand conditions (including the case when two countries have access to the same import sources), or as a conclusion of the sunk LTC capacity cost, which leads the traders to perceive transport cost lower than regulated cross-border entry/exit tariffs. We assume such negative values are signs of the absence of more serious barriers to trade (such as physical or contractual congestion).

To define a meaningful average of the tariff adjusted prices for the 2015-2016 period, we considered the negative values as zero. The average values calculated this way reflect the frequency and the magnitude of price differences exceeding the cross-border tariffs.[61] This methodology estimates the effects of the cross-border tariffs on price differences better than the 'average difference minus tariff' approach, because it takes the full amount of tariff into account only if it is not higher than the price difference. In cases of negative values, a certain amount of the tariff is not effective, and therefore it makes sense to exclude it. Consequently, the average of the (effective) tariffs taken into consideration are generally lower than the real tariffs. Figure 16 summarises the remaining wholesale gas price differences after adjustment of cross-border tariffs.

[61] The average of the cross-border tariff adjusted for across-the-border price differences is calculated as the sum of the quarterly tariff adjusted differences (taking negative values as zero), divided by the number of quarters when the pipeline existed in the price-equalising direction, and therefore the quarterly value can be calculated (8 in most cases). Values marked with * reflects the cases where the unidirectional nature of the pipeline affected the results highly since only differences in one direction could be calculated.

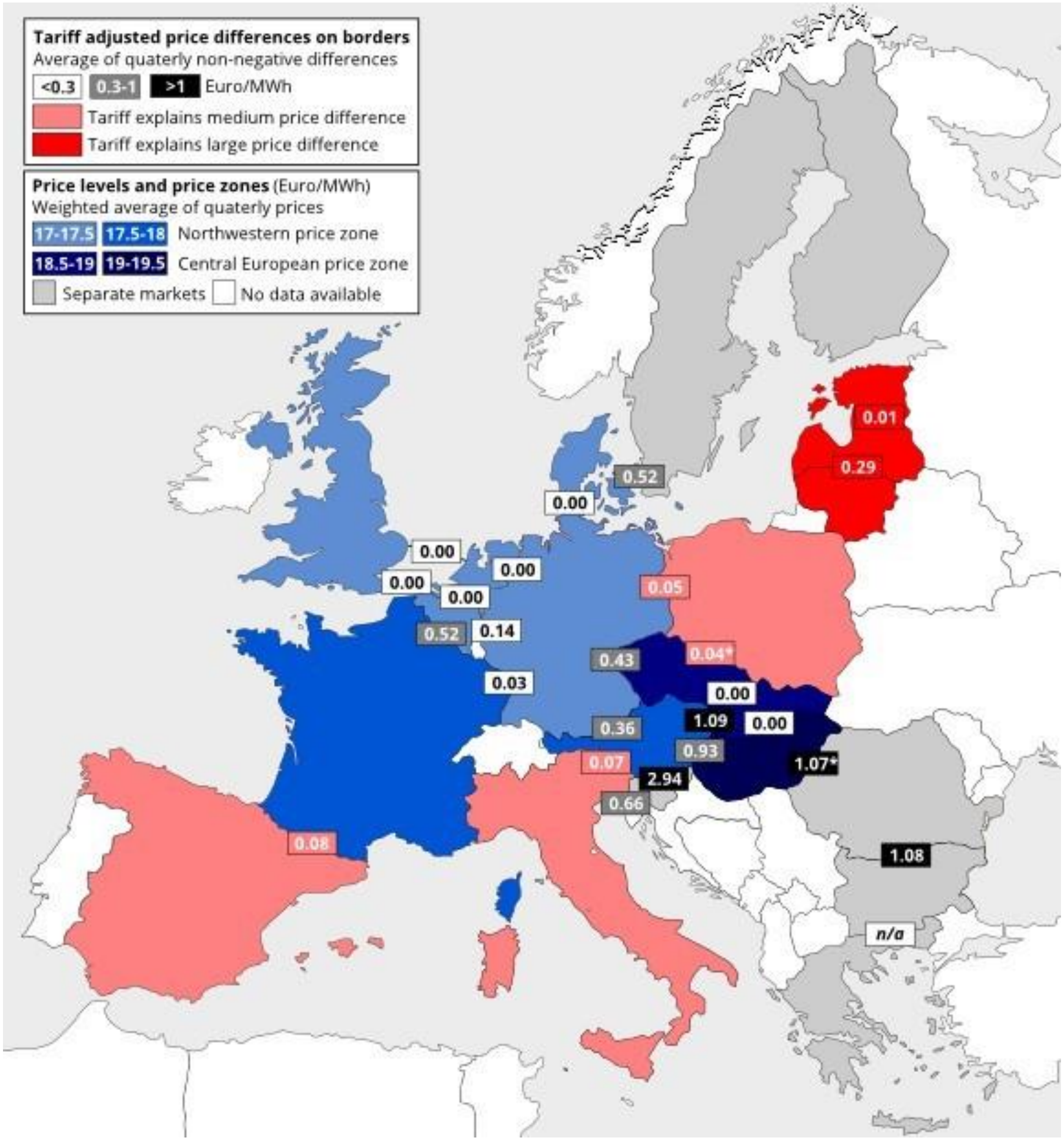


Figure 16: Remaining gas wholesale price differences after cross-border tariff adjustment (2015-2016)[62]

Source: REKK analysis based on EU Quarterly Reports on European Gas Markets

Tariff adjustment confirms the absence of serious barriers to trade between the core countries of the North-Western price zone, and within the Central European price zone, as average tariff adjusted price differences are zero in almost all intra-zone borders. The zero value means price differences were below tariffs in every quarter in the 2015-2016 period.[63] The results indicate that neither the slightly more expensive price level of France and Austria, nor the larger difference between the two price zones can be explained by higher cross-border tariffs, but some degree of barrier to trade should be there on the Belgian-French, German-Austrian and German-Czech borders, and even more serious constraints are suspected on the Austrian-Slovak and Austrian-Hungarian

[62] Tariff adjusted differences cannot be calculated for the Bulgarian-Greek border, as price differences indicate the potential need for transport from Greece to Bulgaria, but this direction is practically non-existent.

Values marked with * reflect the cases where the unidirectional nature of the pipeline affected the results highly since only differences in one direction could be calculated.

[63] The tariff adjusted price difference on the Slovak-Hungarian border was above zero in only one instance, in 2015 Q1, before the interconnector opened. Besides that, the average tariff adjusted price difference is 0.00 on that border too.

borders.[64] Likewise, simple transportation costs cannot be the (sole) reasons for the highest price difference in the sample (Austria-Slovenia border).[65]

However, cross-border tariffs seem to justify medium price differences in the case of Spain, Italy and Poland, and even large price differences between the Baltics.[66] These rose- and red-labelled borders demonstrate the cases where the cross-border tariffs are the main obstacles to achieving full wholesale price convergence.

According to the results, further analyses are required to identify the sources of the price differences on the below-mentioned borders.

- Significant barriers to trade are expected on the following borders (country with lower price indicated first):
  - Austria-Slovenia,
  - Austria-Slovakia,
  - Austria-Hungary.
- Moderate barriers to trade are expected on the following borders (country with lower price indicated first):
  - Belgium-France,
  - Germany-Austria,
  - Germany-Czech Republic,
  - Italy-Slovenia.

For sake of completeness, we also inquire the borders around the North-Western price zone where the cross-border tariff seems to explain the price difference in itself (rose-labelled borders on the map).

3.6 Physical and contractual congestion and customer market foreclosure

As part of our efforts to identify the main barriers to trade on the EU gas wholesale market, we also analysed the flows and bookings on interconnectors to find signs of bottlenecks. Two main types of bottlenecks can be distinguished, which are physical congestion and contractual congestion. By physical congestion, we mean the case when the capacity of the interconnectors is not sufficient to transmit the volume which would be needed to equalise the prices between two countries, and therefore price convergence is limited by the technical characteristics of the pipelines. Contractual congestion is a more difficult case, as it means that the physical capacity would be sufficient, but because of unused booked capacities, available transport capacity is also scarce.

[64] Hub-to-hub price comparison made on the Belgian-French and on the German-Austrian borders, and therefore we believe that the presented differences are sufficiently accurate.

[65] The high values for the the Hungarian-Romanian relation are associated with the period of 2015 Q1 and Q2 when the estimated import price for Hungary was significantly lower than for Romania. Besides that, the differences were below the cross-border tariffs. The Quarterly report publishes a lower price for Romania in the last two quarters (and also in 2017 Q1), and while cross-border tariffs are available for the Romania-to-Hungary direction too, the pipeline is not commercially operable for that direction. Moreover, Romania covered only 3% and 13% of its gas consumption from Russian import (in 2015 and 2016, respectively), and relies mainly on inland production, and therefore the analyses of import prices could be misleading in this case of Romania.

[66] The case of Sweden is unique, as it is connected only to Denmark, a net exporter country with one of the lowest price levels. This may explain the large price differences, but according to our estimations, the transportation tariff on that border is also a record high (for the year of 2015).

The following decomposition of the capacity utilization level of an IP to the product of the capacity booking level and the utilisation level of booked capacity can illuminate the difference between physical and contractual congestion risks as well as the strong relationship between congestion and the capacity booking practices of market participants.

$$\underbrace{\frac{physical\ flow}{firm\ technical\ capacity}}_{\text{physical capacity utilisation}} = \underbrace{\frac{booked\ capacity}{firm\ technical\ capacity}}_{\text{booking level}} \times \underbrace{\frac{physical\ flow}{booked\ capacity}}_{\text{booked capacity utilisation}}$$

The following Table 6 provides for a simple classification of cases for the underlying situation for observed physical capacity utilisation levels.

		Booking level	
		High	Low
Booked capacity utilisation	High	Physical congestion risk	n.a.
	Low	Contractual congestion risk	Underutilised infrastructure

Table 6: The underlying causes for observed physical capacity utilisation levels

Both physical and contractual congestion[67] are trade barriers in that they reduce cross-border trading opportunities in the presence of a price difference on the different sides of an IP.

Physical congestion is a product of simultaneous high-level capacity booking and booked capacity utilisation, indicating a real benefit potential for market participants from using an IP capacity. While physical congestion will prevent full wholesale price convergence between the related market zones, transparent capacity auctions *a la* CAM NC will extract congestion rents, indicate the scarcity value of the IP and can encourage future investment to alleviate the congestion.

Contractual congestion, on the other hand, will potentially foreclose new entrants from using the related unused capacity.

It is important to note, however, that neither physical nor contractual congestion is a necessary condition for price differentials. If alternative routes and sources exist, then even with the presence of congestion it is possible to achieve a single-price zone. But the existence of these market barriers can be an important source of price differences. Nevertheless, congestion can occur not only on pipelines that transmit gas from a cheaper country to a more expensive one, but in the other direction too. It is mainly because of the transit of Russian gas, which flows from East to West, while western countries, as presented above, are typically cheaper than their Eastern neighbours. These flows are not generated by the possibility of arbitrage (but rather create them), so in the actual analysis, we do not attach too much importance to such congestion but focus on the above-mentioned pipelines which could have a key role in achieving price convergence.

[67] According to Regulation (EC) No 715/2009, contractual congestion means a situation where the level of firm capacity demand exceeds the technical capacity.

We conclude our assessment of EU wholesale price differences by identifying customer market foreclosure risk.

3.6.1 Congestion analysis

In our analysis we wanted to identify borders with price differences not fully explained by cross-border tariffs[68]. For the analysis, we used the data from the ENTSOG transparency platform for the year 2016. The dataset contains information about the firm technical capacities, physical flows[69] and bookings about several interconnectors in Europe. We aggregated the different interconnectors at one border into one pipeline, so we examined not pipeline level, but country-to-country relations. For the first check, we transformed the dataset into quarterly data. We assumed if congestion levels are high at such an aggregated level, it is a clear sign of barriers of trade.

To identify potential functioning distortions associated with physical congestion, we determined 70% and 80% quarterly average utilisation thresholds above which we considered an IP moderately or seriously congested. Then we calculated the occurrence of the cases when the ratio of physical flow related to the technical capacity exceeded 0.7 and 0.8.[70] These thresholds can be considered as strict limits. However, we think that if more than 20% or 30% of the pipeline’s technical capacity were not used at a quarterly level, than it can be congested only in short periods, which has to be analysed in detail.

To identify the potential for contractual congestion, we analysed the ratio of bookings to technical capacity as well. Because of the existence of unbundled products, it is possible that a market participant makes a booking at the exit side of the interconnector, but none at the entry side. As a result, there can be differences between the bookings on the entry side and the bookings of the exit side on the same pipeline. To simplify this problem throughout this short market analysis, we generally used the greater value of the two bookings on the same pipeline, because we think if a capacity is booked at one side of the pipeline, it is not possible to use it on the other side as well. As we compare the maximum booking to the technical capacity (which was a minimum) with this method it is possible that we get a ratio which is greater than one. In order to get a

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[68] Our analysis thus complements related recent ACER work. In its latest annual report on contractual congestion, ACER found that in the reference period of 2016-2018, 23 (or about 9%) of the 247 IP sides in scope of the CMP GL were contractually congested. 60% of the contractual congestion at the 23 IP sides is due to the non-offer of firm products with a duration of at least one month of use in 2016/17. In addition to the 23 IP sides that are “certainly” contractually congested, there are an additional 55 IP sides that ACER regarded as “formally congested”. At these points, no yearly capacity product for 2017/18 was offered in 2016. This non-offer does not necessarily hint to contractual congestion, as some TSOs have either decided not to offer capacity beyond one gas year ahead or the CAM NC capacity quota prevented the offer of the Gas Year 2017/18 product. Taken together, the “certainly congested” and the “formally congested” IP sides, their number increased to 78 from last year’s 64. According to the report, many of the congested IP sides are the only ones connecting two entry-exit zones, and thus their congestion may be critical in terms of restricting the free flow of gas across the Union (ACER 2017 Implementation Monitoring Report on Contractual Congestion at Interconnection Points)

[69] In the ENTSOG dataset, the interpretation of physical flow is not obvious, as three different indicators try to capture the usage of a pipeline. These are physical flow, renomination and allocation. In the case of bidirectional pipelines, allocation and renomination are not netted, while physical flow is a netted value. For this reason, using physical flow data would be misleading, as we can measure low utilisation simply because of bidirectional trade. Allocation is post-trade while renomination is before trade data. However, for TSOs it is not obligatory to report allocation data, so there are many missing values in this category. Because of the above-mentioned reasons, we were using renomination data in our analysis, but because of simplicity issues, we will refer to it as physical flow.

[70] As in the ENTSOG data, technical capacities were given both at the entry and the exit point of the pipelines, we considered the minimum of these two values for a given pipeline and summed these capacities at the given border.

picture about the differences between the bookings on two sides, we considered the minimum booking value (bookings on both sides) as well.

We considered a pipeline contractually congested if more than 80% of the technical capacity were booked at quarterly level, so there was no (or very little) freely accessible capacity available, while the pipeline was not physically congested. As a stricter criterion, we also checked that at which pipelines the minimum booked capacity was higher than 80% as well (these cases are also referred to as symmetric contractual congestion). Physically congested pipelines are obviously highly booked as well. It is important to note that even meeting these criteria do not necessarily mean contractual congestion because it is possible the one player booked the capacity and did not use it, but there was no other market participant on the market, who wanted to use that capacity.

Figure 17 summarises the results of this aggregated congestion analysis. On the first part of the graph, borders with high price differences (sum of the dark and the light blue parts of the bar) are listed in order of the unexplained price differences (dark blue bar).[71] In the case of France-to-Spain, Czech Republic-to-Poland, Germany-to-Poland and Austria-to-Italy pipelines, the unexplained price differences are under our previously defined threshold value, but as the raw differences are relatively high, it is reasonable to check whether barriers to trade are also present at these borders.

The second part of the graph shows in how many quarters in 2016 the utilisation of the pipeline was higher than 0.8 (dark red) and 0.7 (light red). In similar logic, the third part presents the number of quarters when the minimum booked capacity (dark yellow) and the maximum booked (light yellow) capacity exceeded 0.8.[72]

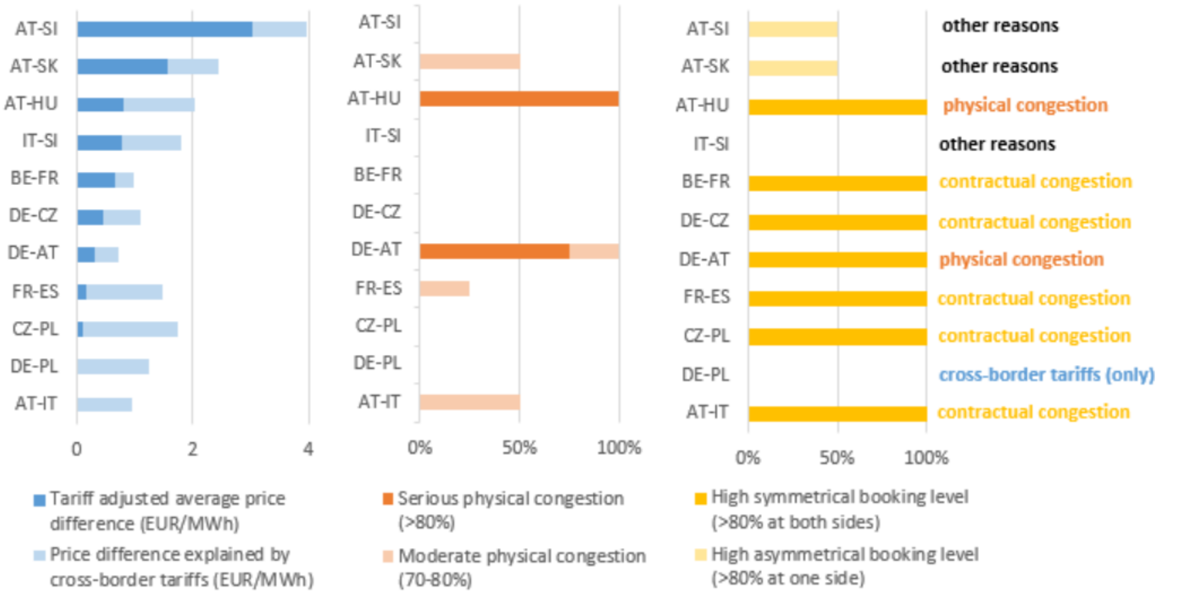

Figure 17: Occurrence of physical and contractual congestion on borders with high price differences (2016)

Source: REKK analysis

According to our results, existence of trade barriers seems obvious in many cases where we identified wholesale price differences in Chapter 3.1. Serious physical congestion is

[71] The graph presents values for 2016, not for the 2015-2016 period as the previous map.

[72] As it was stated earlier, these values are different because of the different technical capacities and bookings on the entry and exit side of the given pipeline.

identified on the Austria-to-Hungary and Germany-to-Austria pipelines, and moderate physical congestion occurs in certain periods on the Austria-to-Slovakia, France-to-Spain and Austria-to-Italy pipelines. The presence of contractual congestion is more frequent and more serious. It affects almost all the examined pipelines, including two borders where the cross-border tariff could explain the price differences too. There are only two borders without sign of barriers to trade, but on the German-Polish connection, the tariff adjusted price difference is zero in 2016, and close to zero for the 2015-2016 period.

However, many of the borders where the price differences are estimated to be the highest are still lacking explanation completely (Austria-to-Slovenia, Italy-to-Slovenia) or at least partially (moderate physical congestion on the Austria-to-Slovakia direction). For this reason, we analysed all the above-mentioned pipelines one by one using daily flow and booking data from ENTSOG, to identify possible congestions.

Perhaps the most interesting case is the Austria-to-Slovenia pipeline. In the case of Slovenia, only the price of the Russian long-term contract was available from the EU quarterly data, which was compared with the Austrian hub price. As in 2016, approximately just half[73] of the Slovenian import came from a Russian long-term contract, and the rest has been reported mainly as import from Austria. Therefore, the real price difference between the countries was probably smaller than the data indicates.

Even with this fact in mind, it is interesting that congestion is not frequent on that interconnector. Figure 18 shows the utilisation rate of the pipeline, by presenting the technical capacity, the bookings and the actual physical flows in 2016 and 2017.

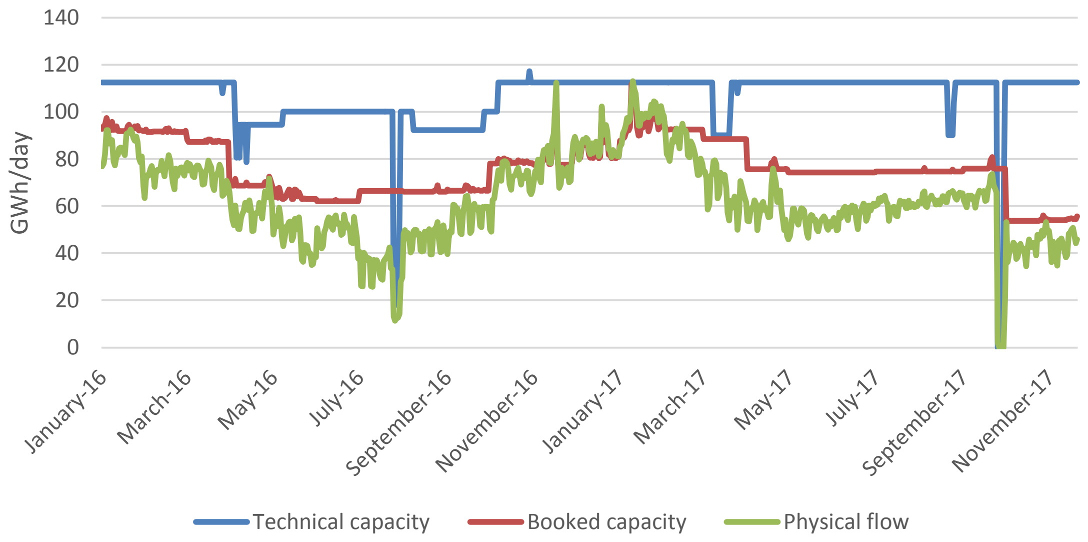

Figure 18: Utilisation of the Austrian-Slovenian interconnector (2016-2017)

Source: REKK analysis based on ENTSOG data

It is visible that congestion only occurred on some days in 2017 Q1, when the interconnector was almost completely utilised. On top of that, the average utilisation rate of the pipeline was around 60% and it often occurred that the booked capacity was lower than the actual usage, and both were significantly lower than the technical capacity. This means that both in 2016 and 2017, there were periods in the year, when with the actual market conditions there was no demand for the usage of the pipeline,

[73] It is below 40% based on the ACER market monitoring reports for the year 2015 and 2016, but ca. 60% based on the Gazprom export data (Factbook "Gazprom in Figures 2012–2016").

which to some extent contradicts our price analysis as price differences existed in those cases.

There are several questions which emerge with respect to the Austria-Slovakia border as well. For Slovakia, the EU quarterly reports provide only the price of the Russian long-term contract. However, in the case of Slovakia, the majority of the country's gas supply was coming from Russia, so it can be considered as a good indication of the actual wholesale price. The main gas flow direction on the Austrian-Slovakian border is the Slovakia-to-Austria direction, since it is a transit route of the Russian gas to Austria (and to Slovenia, Italy, and in certain periods and amounts to Hungary and Croatia). However, as the gas prices are higher in Slovakia than in Austria, we expect the need for transport in the other direction, which means the gas had to be transported back to Slovakia, until the price differences disappear, otherwise some barriers to trade must be there. By looking at Figure 19, it is visible that at some period the booking rate reached the technical capacity. On the other hand, in general there was plenty of available capacity present on the interconnector most of the year, so the periodical potential contractual congestion does not explain clearly the significant price difference between the two countries.

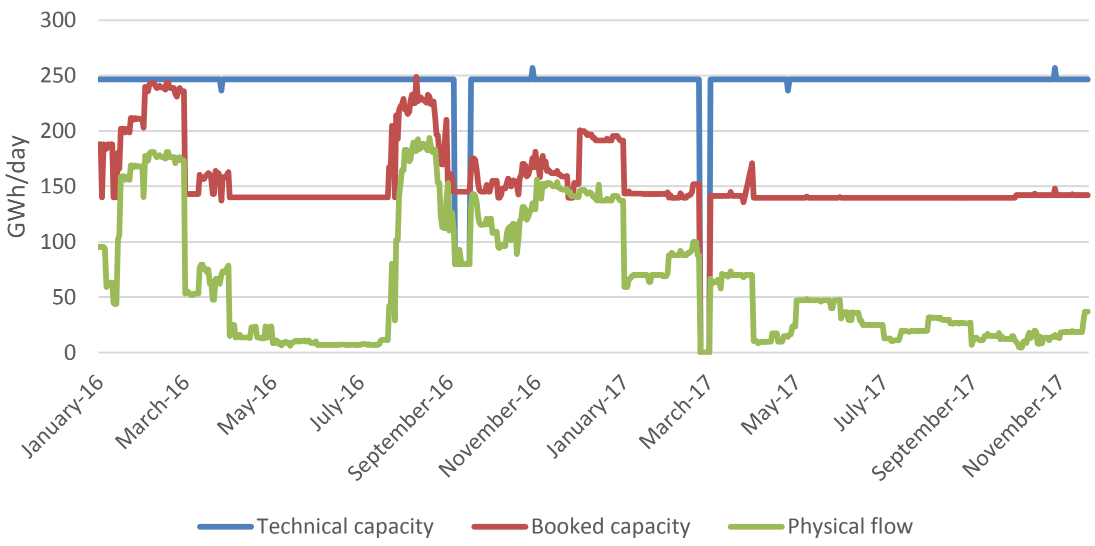

Figure 19: Utilisation of Austrian-Slovak interconnector (2016-2017)

Source: REKK analysis based on ENTSOG data

The third critical pipeline which was identified is the Austrian-Hungarian interconnector. There is no need for deep analysis for this relation as in all quarters in 2016 the average utilisation rate was higher than 85%, and in 2017 Q2 and Q3 even higher than 90%. That means that in line with our price data, the pipeline is indeed physically congested, so price differences cannot be diminished because of the physically constrained trade opportunities.

There are several interconnectors in the Figure 19 where price differences still occur even after the subtraction of transportation tariffs, but the differences are not that critical as with the above-mentioned three relations.

The Slovenian market is overpriced not only in comparison with the hub-priced Austria, but also with Italy, where import prices are available (for almost the whole import volume, including the Russian import). According to the Quarterly reports, the Russian LTC price is also lower for Italy than for Slovenia. However, it is still possible that if we consider the Slovenian spot trades as well, the price differences would be much smaller.

Nevertheless, Italy is largely supplied with natural gas through Austria, so the situation on the Italian-Austrian border is possibly affecting the Italian-Slovenian pipeline as well.

With these factors in mind, perhaps it is not that surprising that the utilisation of the Italy-to-Slovenia pipeline was close to zero in the investigated time period. Some minimal flow occurred in 2016 Q1 and 2016 Q3. It is also interesting to note that some minimal flow occurred in the other direction as well in 2016 Q3, which weakly supports the theory that maybe there were no actual price differences between those countries.

The following Figure 20 shows the utilisation of the Austria-to-Italy interconnector in 2016 and 2017. From the data, it is difficult to tell whether physical or contractual congestion is more frequent as in some time periods the pipeline is almost fully utilised, while in others there is no usable capacity because of the bookings. But we can clearly conclude, that the Austria-to-Italy interconnection point is generally congested, which possibly hinders trade on the Italy-to-Slovenia pipeline as well.

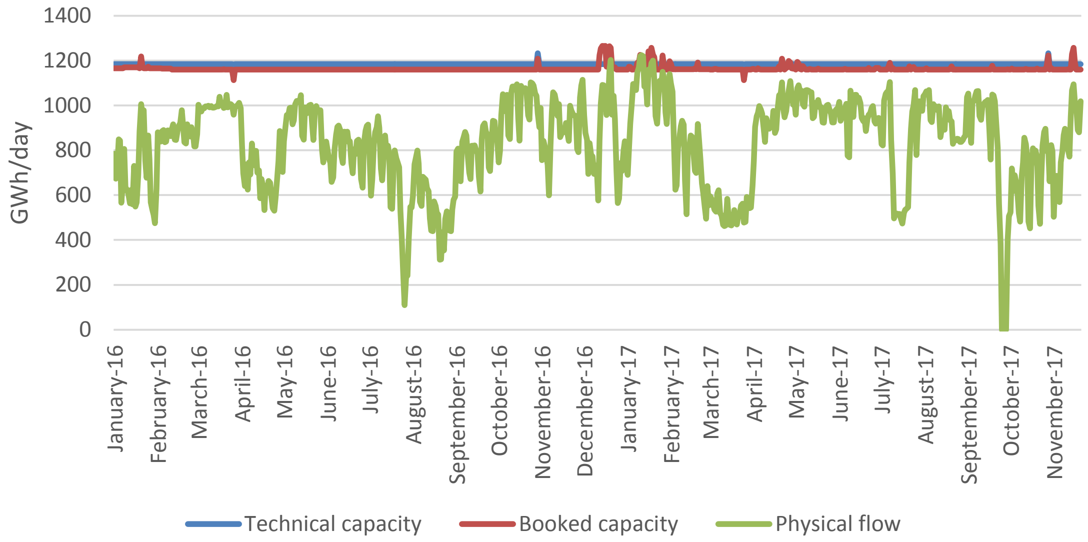

Figure 20: Utilisation of Austrian-Italian interconnector (2016-2017)

Source: REKK analysis based on ENTSOG data

Figure 21 presents the utilisation of the Belgium-to-France pipeline.[74] The graph clearly presents that the actual usage of the pipeline was never close to its technical capacity. However, the maximum booked values are close to the interconnector's technical capacity and even the minimum values are very close to it. This means that the rate of available capacity was low, so there is a significant threat of contractual congestion on this pipeline.

[74] At the Belgian-French border, there are three exit and two entry points that we have aggregated into one pipeline. This aggregation, however, implied some difficulties as on the Blaregnies (H) pipeline, the technical capacity at the entry and exit side is different, and the bookings on the two sides are different as well. For this reason, similar to our earlier analysis for the technical capacity, we used the smaller value, while for booking, we report the minimum and maximum (depending on whether we considered the entry or the exit side bookings) bookings as well. Blaregnies (L) is almost symmetric, so on that pipeline, there are no significant differences between the two sides.

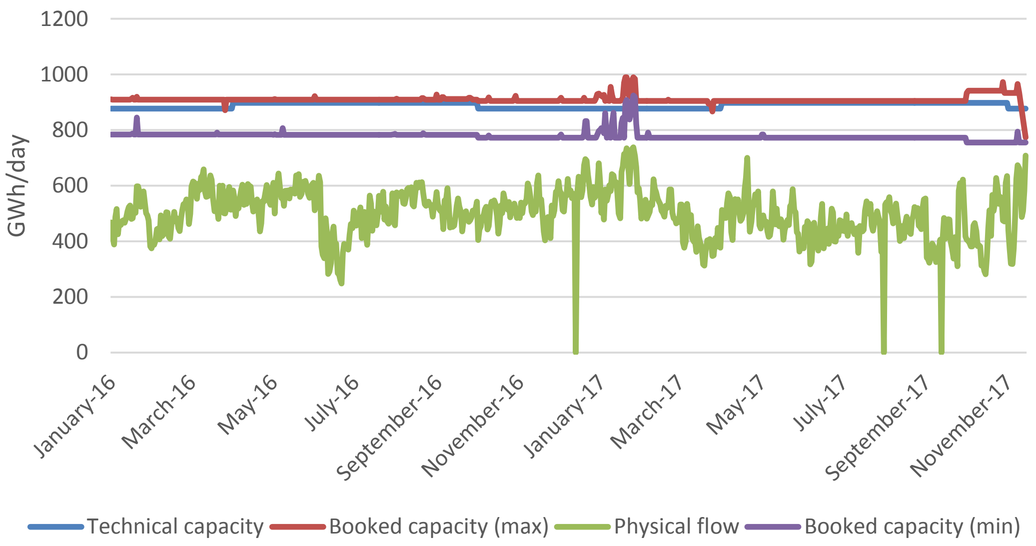

Figure 21: Utilisation of Belgian-French interconnector (2016-2017)

Source: REKK analysis based on ENTSOG data

There are many interconnection points on the Germany-Czech Republic border that were aggregated into one pipeline. A similar problem emerges on that border as on the Belgian-French one. Because of the high number of interconnection points for this relation, we only present aggregated average data for quarters in a similar structure as we used in this current analysis.

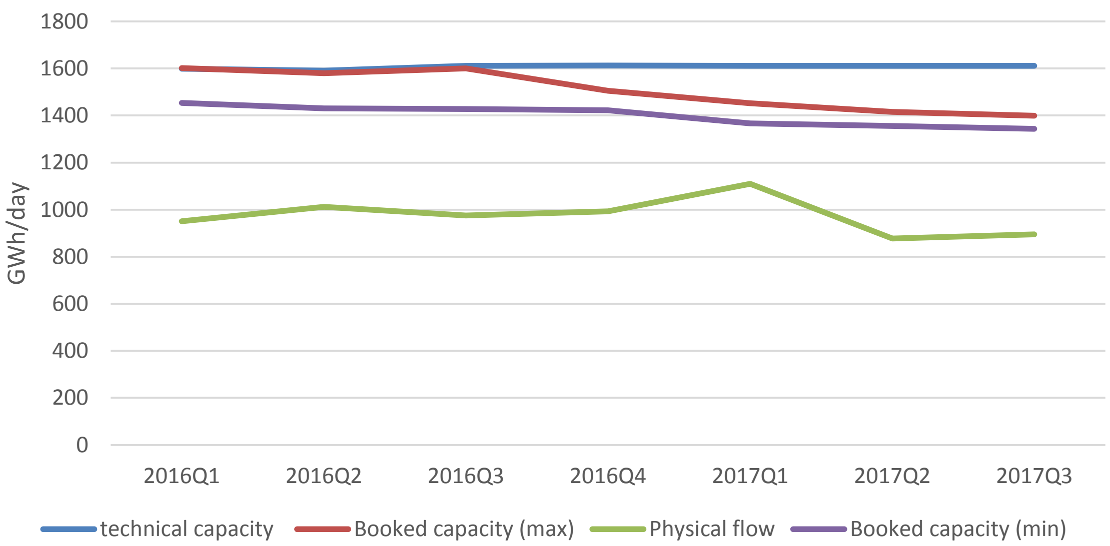

Figure 22: Utilisation of German-Czech interconnector (2016-2017)

Source: REKK analysis based on ENTSOG data

From Figure 22, it is identifiable that the German-Czech interconnector is not heavily utilised. The average quarterly utilisation rate never goes near to the technical capacity. On the other hand, it is also evident that the booking rate on the pipeline is much higher. The maximum booked capacity is generally the same as the technical capacity until 2016 Q3, while the minimum booked capacity is also relatively high, which is a strong signal for potential contractual congestion. The rate of booked capacities (both maximum and minimum) started to decrease in 2017, which decreased the threat of contractual congestion on that border. It is interesting, however, that massive convergence is observable between the maximum and minimum booked capacities, which is likely to be associated with the EU regulation that supports bundled products.

The case of the German-Austrian border is similar to the Austrian-Hungarian one: the presence of congestion is obvious. The average utilisation of the pipeline in 2016 was higher than 80% in three quarters, while in Q4 it was "only" 75%. So, the barriers to trade exist between Germany and Austria.

We also investigated the Czech-Polish interconnection point. The situation is very interesting at this border, because in some quarters the wholesale price in Poland was higher while in others the wholesale price in Czech Republic was significantly higher. A significant issue in this relation is that there is no pipeline from Poland to Czech Republic, which can seriously hinder price convergence. The technical capacity from Czech Republic to Poland is also small, at around 28 GWh/day.

Generally, the Czech Republic-to-Poland pipeline was not used for gas transport in 2016, but the possibility of contractual congestion still emerged on the pipeline. The reason for this is that in all quarters of 2016, the booked capacity of the pipeline was higher than 90%. This fact is more complex as the firm technical capacity of this pipeline is seasonal, but in all seasons almost all capacity was booked. It is possible, however, that market players simply did not want to use the pipeline for gas transport. This theory is supported by the fact that since the end of October 2017, the pipeline has been heavily utilised.[75]

We also analysed those pipelines where raw price differences were big, but these were generally explained by transmission tariffs. We already showed that the Austria-to-Italy interconnector is congested. However, it is not the case with the German-Poland pipeline. At this border, both the booking and the utilisation rate are very low, so despite the significant raw price difference, there is no barrier to trade other than the cross-border tariff. Finally, it was visible from our summarising table already that the booking rate (both maximum and minimum) on the French-Spanish border was higher than 80% in all quarters of 2016 (even higher than 90% in two quarters) which indicates the threat of contractual congestion.

To conclude, in most of the analysed cases some form of congestion is possibly present. We identified three interconnectors where our data does not indicate congestion, but price differences were observable in 2016, which are the Austria-to-Slovenia, Italy-to-Slovenia and the Austria-to-Slovakia relations. In all other cases, price differentials were to some extent explainable.

3.6.2 Duration of long-term bookings on contractually congested IPs with unexplained price difference

We also investigated interconnectors on those borders where the threat of contractual congestion emerged, and how long the current bookings will hold. For the analysis, we used a dataset provided by ENTSOG, which summarises the currently booked capacities for future dates. The similar problem of asymmetry emerged with bookings for this dataset as was presented earlier, so in this analysis when we refer to bookings, we are using the maximum booking value for the given relation. Pipelines were aggregated to

[75] The Czech NRA argues that the IP is not used due to a large increase of entry tariff on the Polish side which occurred after binding open season. As explained by the Polish regulator, the general tariff increase was due to the implementation of ambitious investment plan of the Polish TSO. The expected business model has been completely changed for the capacity owner who booked 90% of the capacity. In most cases, this entry-exit point (together with gas price) is uncompetitive compared to the other entry points to Poland due to a combination of local prices and entry/exit tariff combination. This statement could be justified by the fact that there is no demand for the capacity which is offered via a congestion management procedure (long-term UIOLI).

country level interconnectors as well. As in the modelling, we will present results from 2020 and 2025, we used these for dates as well, when we considered bookings. For the calculation, we used the technical capacity values from 2017.

Table 7 collects the results of this small comparison. It shows the extent of the technical capacity to what it is currently booked for 2020 and 2025.[76]

From country	To country	Booking 2020	Booking 2025
Austria	Italy	100%	17%
Belgium	France	98%	42%
Czech Republic	Poland	93%	93%
Germany	Czech Republic	71%	74%
France	Spain	89%	47%

Table 7: Bookings on those interconnectors where the threat of contractual congestion existed in 2016 (2020, 2025)

Source: REKK analysis based on ENTSOG data

Most of the investigated interconnectors follow a similar pattern. Until 2020 most of the bookings that currently exist will remain in place, but by 2025 these values will fall below 50%. The dynamics of the Czech Republic-to-Poland and Germany-to-Czech Republic pipelines are different, as on the former the ratio of booked capacities does not decrease until 2025, while on the latter after a drop to a 71% booking rate in 2020, it increases to 75% by 2025.

3.6.3 *Market foreclosure through commodity long-term contracts*

We also examined the possibility of market foreclosure since the long-term commodity contracts with take-or-pay clauses are able to lock the customer base (customer foreclosure) for a longer period, which decreases the short-term contestability of the market. If the minimum take-or-pay levels in these contracts are close to the consumption or the import need (consumption minus inland production) of the country, then the national wholesalers have limited incentives to purchase gas from more competitive sources and have limited ability to react to price movements. We focused on the countries with borders where price differences couldn't be explained neither by cross-border tariffs nor by any kind of congestion, but we also present the situation for other net importer countries.

Figure 23 presents the estimated ratios of minimum take-or-pay quantities to consumption and to import need. We argue that the ratio to import need is a better proxy for customer foreclosure since production has generally a prioritised role before imports. The estimation is conservative; therefore, the presented values are likely to be lower than the real ratios.[77] However, we note there are examples when even the

[76] The maximum of entry and exit booking rates are shown in the Table.

[77] The minimum ToP quantities are derived from the ACQ values by using 15% flexibility in every case (minimum quantity = ACQ*0.85). We note that such high flexibility is not general. The presentation of two-average values reflects also on flexibility since it assumes that the demand and the supply have to meet only in longer term (it flattens the yearly differences in consumption and production). The ACQ values are collected from several sources (e.g., Commission database and REKK EGMM inputs) and in case of differences we take the lower value into consideration.

minimum ToP quantities were not effective (or at least the takeover could be delayed), so it is reasonable if we consider the ratios close to 75% or even higher to 100%.

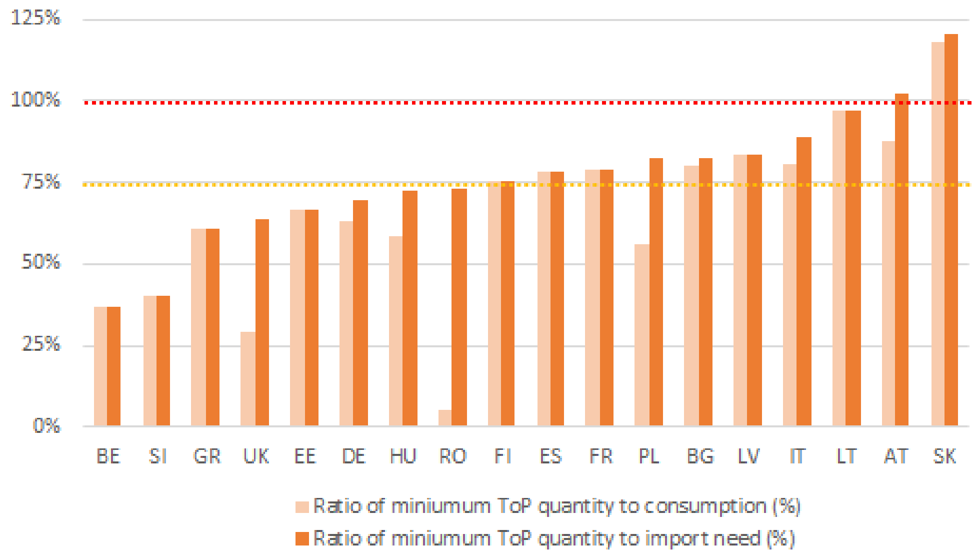

Figure 23: Estimated ratios of minimum take-or-pay quantities to consumption and to import need (combined values for 2015-2016)

Source: REKK analysis based on Commission database and REKK EGMM inputs

Based on the results, one of the unexplained questions seems to be clearly answered: the price difference on the Austrian-Slovakian relation can be justified by the fact that the contracted minimum quantity for Slovakia is significantly higher than the consumption (the production is not significant in the country). Even if the takeover of minimum quantities can be delayed for later, it is hard to imagine that a wholesaler with such a long-term contract will look for other sources and has incentives to purchase gas from Austria.

A close to 100% minimum ToP quantity to consumption ratio can give an additional reason for explaining high prices in some countries, on the borders of which some kind of trade barrier is already identified (Lithuania), but we argue that even a 70% ratio can limit the contestability of the market. The high value for Austria is somewhat surprising based on the price differences, especially if we consider the physically congested Germany-to-Austria border, which brings extra supply to the country. At the same time, these volumes flow onward to Hungary, Italy and Slovenia, and regarding the prices, it is reasonable to assume that the better access to western sources influences the price negotiated with extra-EU suppliers.

On the other hand, the price differences regarding the Slovenian borders cannot be explained by the excessive long-term contract. If the available prices are reliable for Slovenia and its neighbours, then another (probably institutional or regulatory) issue must be in place.

3.7 Conclusion on our in-depth analysis of 2015-16 wholesale price differences

Our in-depth analysis of 2015-16 wholesale price differences within the EU suggests that the European gas market has not yet reached full integration. While the wholesale gas markets of the five cheapest countries (Denmark, Belgium, the United Kingdom, the Netherlands, Germany) create a single price zone, the somewhat costlier French and Austrian markets can be classified as second line members of this North-Western price zone, whose integration is not perfect. Within the mid-priced Southern/Eastern belt around the North-Western price zone, the Czech, Slovak and the Hungarian markets show signs of a higher-level integration with each other. Other mid- or high-priced markets (e.g. Italy, Slovenia, Poland, the Baltics) are not integrated enough with any neighbouring market to be classified into the same price zone, indicating significant barriers to trade on their borders.

The presence of different trade barriers (the lack of interconnectors; cross-border tariffs; physical and contractual congestion, customer foreclosure) as well as differences in upstream market structure and exposure to upstream suppliers could explain remaining wholesale price differences.

We identified eight examples where remaining price differences could have justified cross-border trading, but the lack or unidirectional capability of the interconnector prevented transactions. Specifically, potential connectors of France-to-Italy, Poland-to-Lithuania, Hungary-to-Slovenia and Greece-to-Bulgaria would foster cross-border trading, of which the Poland-to-Lithuania pipeline (addressed by the GIPL project) would play the largest role in fostering price convergence.

Cross-border transportation tariff adjustment confirmed the absence of serious barriers to trade between the core countries of the North-Western price zone and within the Central European price zone, as average tariff adjusted price differences were zero in almost all of these intra-zone borders. Cross-border tariffs seem to justify medium price differences in the case of Spain, Italy and Poland, and even large price differences between the Baltics. However, neither the slightly more expensive price level of France and Austria, nor the larger difference between the North-Western and Central European price zones could be explained by higher cross-border tariffs. Additional trade barriers should explain remaining price differences on the German-Austrian, Belgian-French and German-Czech borders and the borders of Austria with Slovakia, Hungary and Slovenia.

Physical congestion explains the remaining price differences at the German-Austrian and Austrian-Hungarian borders, while contractual congestion seems to be the likely explanation for remaining price differences at the Belgian–French and German-Czech directions. The remaining price difference for Slovakia compared to Austria is explained by a very high Russian-Slovak contract ToP quantity.

Since the presence of barriers to trade is a necessary but not sufficient condition for price differences, we also demonstrated the significant differences in market structure both at country and price zone level. We found that both company level market concentration and the diversification of supply sources may have an effect on prices, at least to a certain extent.

Our analysis showed that a diversified import portfolio can result in low prices even if a country is poorly integrated into the internal EU market (Greece), while high upstream concentration does not lead to high prices if a country is well-integrated into the internal market (Austria). However, the whole analysis has to be interpreted in the context of the EU level upstream market concentration, which suggests that even the fairly well integrated and relatively low-priced North-Western gas market(s) cannot be considered highly, just sufficiently well-functioning.

3.8 The future of LTCs in the EU and its consequences for market development

Until the end of the 2000s, natural gas trading in continental Europe had been built on long term commodity and capacity contracts. Access to Member State level gas markets for outside suppliers has historically been granted by LTCs between the suppliers and the local incumbent gas companies. Since market access provided by legacy LTC has often been exclusive and since the majority of these LTCs are still valid, a discussion of the current and future role of LTCs on the EU gas wholesale market is necessary to formulate a vision about the future of the IGM.

We are interested in to what extent market foreclosure, relying on long-term commodity and/or capacity contracts, can restrict further market integration.

Commodity contract-based foreclosure might prevail if minimum LTC take-or-pay quantities cover close to the full consumption or import needs of a country or market zone.

Long-term and large-scale capacity contracts on intra-EU IPs that are critical in supplying certain countries and regions by suppliers with significant market power can permanently restrict access to key supply routes for alternative suppliers or producers. We will discuss market foreclosure risk by long-term capacity contracts in Section 3.8.3.1.

To support this understanding, we summarized the brief history, main features and the conclusions of their recent renegotiations of legacy LTCs in Annex 4. Before we turn to the discussions on congestion and market foreclosure, we briefly summarize our conclusions on the likely future of long term commodity and capacity contracts on the European gas market.

3.8.1 The future of commodity and capacity LTCs and their impact on EU gas market development

The objective of this assessment is to formulate alternative visions on the future of commodity and capacity LTCs in the EU and to select the one that will underlie our quantitative welfare analysis in Chapters 7. The analysis also supports the development of alternative regulatory proposals in Chapter 6. We are particularly interested in the expected duration, contracted quantity, flexibility and pricing of future long- or mid-term contracts.

Based on the analysis provided in Annex 4, Table 8 below summarises our conclusion on how the major characteristics of LTCs have changed due to renegotiations and recent new contracts.

	Duration	ACQ	Pricing	Price review option	Arbitration clause	ACQ / Flexibility	Delivery point
Legacy LTC characteristics	15-25 years	60-100% of import needs	Netback market value to cheapest alternative; typically oil-product (or partly coal) indexation	Only once in every three years	If parties fail to agree to a new price level following a price review	Take-or-pay obligation with ± 15%	Border of buyer's country IP
Renegotiation impacts	Duration reduced to 3-15 years	Maintained or occasionally reduced	Temporary discounts and structural changes to the pricing formula. Introduction of full or partial, direct or indirect hub-indexation	Possible much more frequently	n.a.	ToP obligations have sustained by and large; first ToP obligations were temporarily lifted by Gazprom to prevent mid-streamer partners going bankrupt. In the renegotiation round ToP has lost importance as volume certanity of the seller was eroded by all means (increased flexibility, prolongation of contracts, reduced ACQ).	EU border for Sonatrach, Statoil and LNG. Intra-EU (hub or IP) for Gazprom
Renewed contract characteristics	3-10 years when no new transmission investment involved	Related to flexibility	Hub-linked (direct or indirect)	No need	n.a.	Reducing with decrease in ACQ and increase in hub-indexation share	EU border for Sonatrach, Statoil and LNG. Intra-EU (hub or IP) for Gazprom

Table 8: Change of major LTC characteristics due to renegotiations and in new contracts, 2010-17

Source: REKK / EY analysis

We expect long-term (or we would rather call multi-year) commodity contracts to remain part of the EU's gas wholesale trading structure up to at least the mid-2030s. Multi-year commodity contracts can reduce volume risk for sellers and can fit the portfolio of buyers with large customer portfolios.

3.8.2 Future LT commodity contract characteristics

Contract duration

Neumann, Rüster and Hirschhausen (2015) investigated both European and Asian gas supply contracts. They concluded that contract duration has reduced from 35 to a maximum of 15 years in the last decade. According to the study, 'very long contract durations of 30 or more years - even up to 40 years - are no longer common. In contrast, shorter agreements covering five to ten years increasingly complement the typical 20-25 years contracts'. Asian and LNG contract durations tend to be longer than European and pipeline contracts.

The trend of decreasing contract duration is common irrespective of the region and can be observed namely on the deliveries to Europe and Turkey, where a drop to five to ten years from the original 25 years has occurred, as well as on LNG supplies to Europe. The European situation is illustrated in Figure 24.

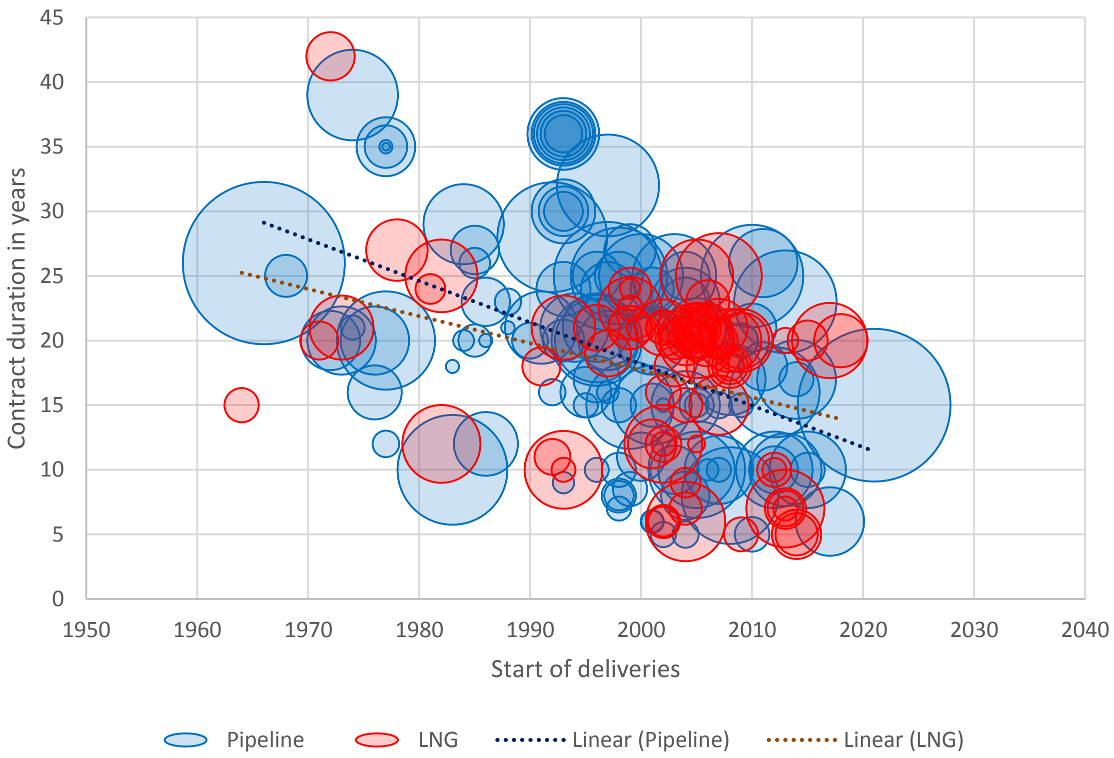

*Figure 24: Contract duration by start-up year of deliveries of individual long- and mid-term commodity contracts in EU and Switzerland**

** The size of the circle corresponds to the size of the annual volume of the closed contact.*

Source: EY analysis based on data of Neumann, Rüster and Hirschhausen (2015)

During the 2000s, four CEE countries re-contracted with Gazprom (Austria, Poland, Slovakia and Romania). Contract duration at that time was still in the 20-25 years range. However, after 2010, new contracts with Gazprom shortened significantly. Figure 25 depicts the development of LTC contract duration in this region.

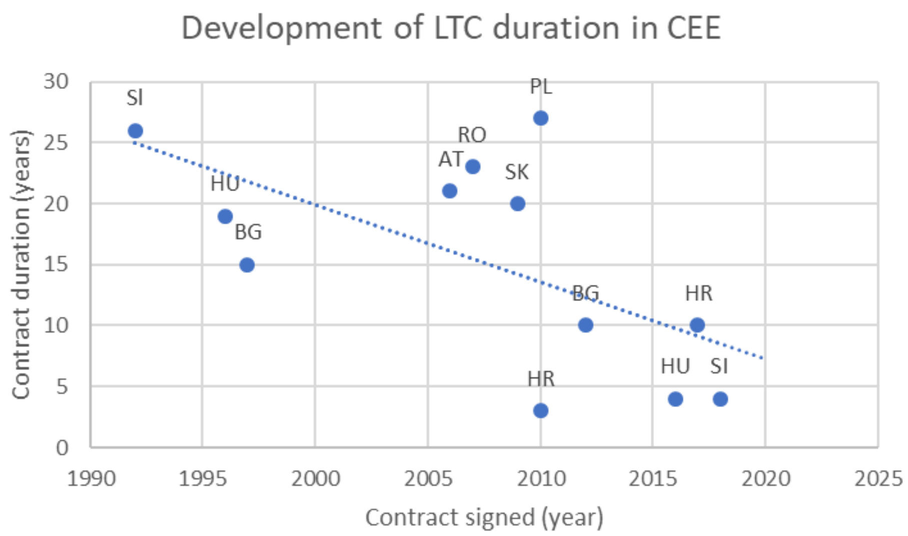

Figure 25: The development of LTC duration in CEE

Source: REKK analysis

According to recent contracting trends, we expect a reduced duration for multi-year commodity contracts of 3-10 years, although producers and buyers might have a different idea of the optimal contract length.

Contract quantity and flexibility

Due to the negative recent experience with being over-contracted, and the remaining uncertainty regarding European gas demand, buyers might want to minimise their volume risk by covering only the "baseload" gas consumption of their portfolios from LTCs, while covering the rest from more flexible sources.

If producers accept that buyers seek shorter and sliced contracts instead of a single one and they have limited appetite to take the LTC vs hub price risk, they might offer a more diversified product portfolio. Products with different volumetric and price risk combinations are expected to be offered, while the contractual price may also depend on the market share provided by the contract. We expect sellers to offer reduced volume flexibility in case of a small contract relative to the market size, and in case of increased share of hub indexation.[78] However, in countries with less supply diversification options, longer and larger contracts might prevail.

Contract pricing

Most of the new contracts are committed to full hub indexation. For example, Azerbaijan confirmed that part of its Shah-Deniz 2 gas will be priced on the basis of gas-to-gas competition. Statoil also signed new hub-linked supply contracts with European buyers. Sonatrach is also reported to be retreating from oil-indexation and is also willing to reduce the length of its contracts.[79] However, Gazprom seems to prefer not to give up oil-indexation fully, but rather apply an "indirect spot pricing" regime when oil-indexed prices apply for settlements if they remain within a pre-defined range around forward

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[78] This vision is a bit contradicting to that of Stern and Rogers (2014) saying that '*International oil companies (IOCs) and European pipeline exporters will tend to sell gas at hubs, but may continue to supply larger customers on up to 10 (but probably 1-5) year, hub-related contracts with significant volume flexibility.*'
[79] https://www.platts.com/latest-news/natural-gas/algiers/algerias-sonatrach-to-revise-down-length-of-long-26672039

hub prices, and prices at the border of the range otherwise (see Figure 26 for an illustration).

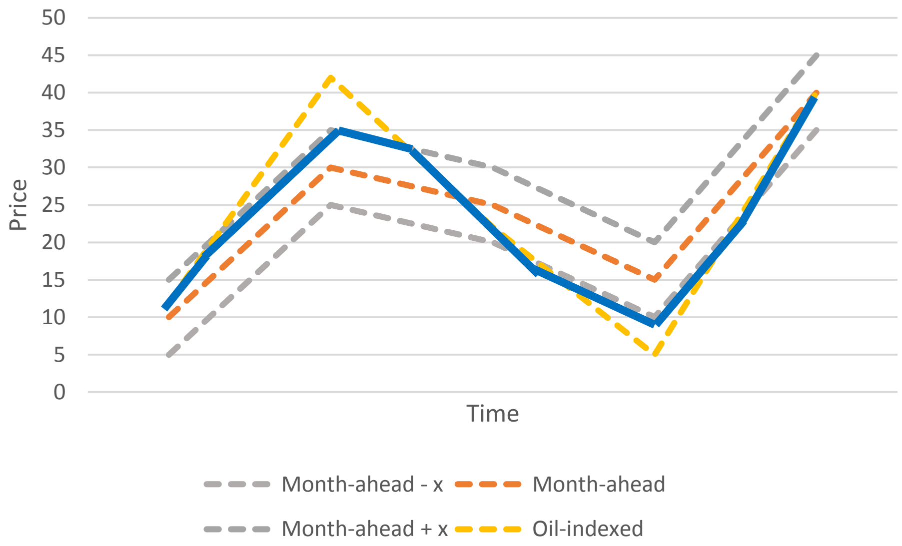

Figure 26: The mechanism of "indirect spot pricing"

Note: The solid blue line indicates the applied settlement price that moves within a pre-defined range around the forward hub price.

Source: Franza (2014) p. 15.

Up to 2025, we expect LTC pricing to remain location and contract dependent and to adjust to the closest competitive threat for the seller. In well interconnected and liquid market areas like North-West Europe, the pricing benchmark is hub-pricing.[80] In more isolated regions (e.g., the Baltic states), it might be the LNG drop-off price at the closest terminal or the price of the competing pipeline gas (e.g., TAP in Greece).

We conclude that mid-term (3-10 years) commodity contracts are likely to remain part of the EU's gas wholesale trading structure up to at least the mid-2030s. Contract size is difficult to forecast because of the conflicting interest of sellers and buyers. We expect a portfolio of contracts with different duration and different volumetric and price risk profiles to replace single LTCs. We expect producers to offer reduced volume flexibility in case of smaller contracts compared to the market size and in case of increased share of hub price indexation. Up to 2025, we expect LTC pricing to remain location and contract dependent and to adjust to the closest competitive threat for the seller (liquid hub for more interconnected regions; LNG or competing pipeline for more isolated regions).

3.8.3 Future LT capacity contract characteristics

Legacy long-term commodity contracts used to be complemented with long-term capacity contracts. Delivery point clauses of LTCs define the route and point of delivery for the traded commodity. Figure 27 depicts the current and likely future development of capacity booking ratios on the European grid as at October 2017.

[80] https://www.engie.com/en/journalists/press-releases/statoil-gas-supply-contracts/

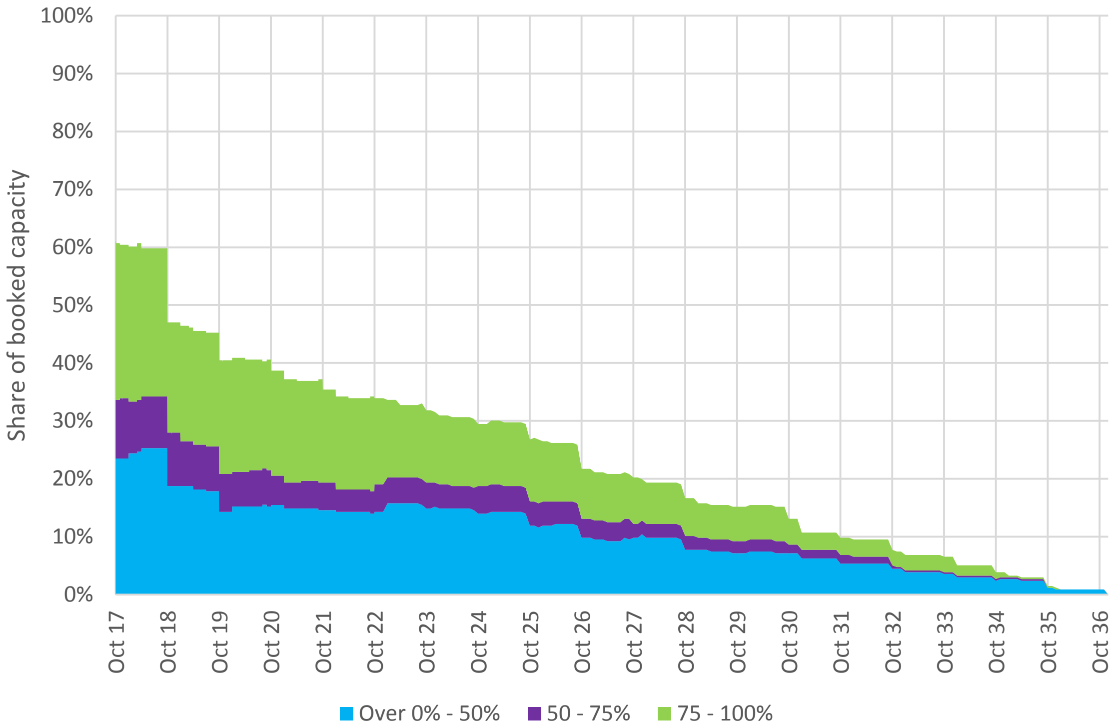

Figure 27: Firm booked capacity / firm technical capacity ratios on EU IPs as at October 2017

Source: ENTSOG data analysed by EY

Long-term capacity contracts are traditionally needed to ensure financing for new, large-scale infrastructure investments and to provide revenue certainty for TSOs. In addition, LTC holders require them to contain the risk arising from access and costs of transmission services.

- Both arguments are valid for new pipeline investment. However, they are not fully justified in the case of existing pipelines. TSO's exposure to revenue volatility is rather limited. Demand for transmission services is driven by aggregate annual consumption that is rather stable in the medium run. Long-term bookings would be replaced by short-term bookings where the transmission service was required, and thus bringing the actual use of the system closer to actual customer needs. In addition, TAR NC ensures a compensation mechanism for revenue shortfalls. The risk of revenue shortfalls is, however, limited by the fact that short-term capacities are usually priced higher.
- If sufficient transmission capacity exists, the risk exposure of LTC holders is also limited. They don't have to engage in long-term capacity contracts, as hedging instruments can also offset potential losses arising from volatility of the transmission fee in case of any potential shortage of capacity at IPs.[81]

While it is not indispensable to contain TSOs' and LTC holders' risk exposure, the system of long-term capacity bookings is hardly compatible with an efficient capacity allocation, when allocation is more closely related to the actual use of transmission capacities.

[81] Similar instruments (financial transmission rights) have already been developed on electricity markets, and more widespread use is foreseen after full implementation of the CACM network code.

Additionally, long-term capacity bookings create contractual congestion and market foreclosure risk.

We think that the gradual dismantling of LT capacity bookings due to the expiry of existing contracts creates an opportunity for the future EU gas market. The system of incremental capacity allocation, according to CAM NC, ensures financing for needed new infrastructure. However, regarding existing infrastructure, decreasing long-term bookings could decrease contractual congestion and capacity hoarding, and thus improve the efficiency of the use of the existing transmission network.

If long-term bookings are replaced by short-term bookings, depreciated assets with very low or no utilisation could be gradually decommissioned[82] or, if kept for security of supply or strategic reasons, could be paid by the customers of those market zones enjoying these benefits. The revenue certainty of the TSO to recover their justified costs will be ensured by the national regulators.

Delivery point

Based on their experience with stranded and unused long-term capacity bookings, we do not expect EU midstreamers to take additional risks and book existing intra-EU IP capacities for the long term, knowing that optimal supply routes can rapidly change due to changing supply-demand conditions.

However, we expect that extra-EU suppliers with significant market power will wish to continue with long-term capacity bookings on intra-EU IPs, and thus strengthening their market position downstream. However, for market development this would create unnecessary risks.

3.8.3.1 *Market foreclosure risk by long-term capacity contracts - the results and lessons of the Prisma auction in March 2017*

A large scale capacity auction applying CAM NC principles took place on 6 March 2017. In this Section we provide a brief analysis of the auction results of the PRISMA platform, which covers most of the European Union's natural gas transmission grid. Available data (ENTSOG, Prisma) on capacity reservations at cross-border points show that before this auction the largest long-term capacity bookings were within a one- to three-year horizon. Capacity was noticeably reserved until 2036.

In our view, the auction of 6 March 2017 led to distorted outcomes. True competition took place among midstreamers only in the 2017-2018 gas years, while after 2019 only one market player booked capacities. Moreover, the network capacity usage for the most important West to East transportation route was booked for 20 years in favour of Europe's dominant external supplier. By paying about EUR 9 billion capacity booking fees for the post-2020 period, Gazprom has again secured its control over the supply of Central-Eastern Europe and gas deliveries to the Ukraine.

Auction results

Altogether 2,165 unique auctions took place on 6 March for each point and each year, with capacity bookings performed for 345 auctions.

[82] New long-term capacity bookings are also unlikely for those assets.

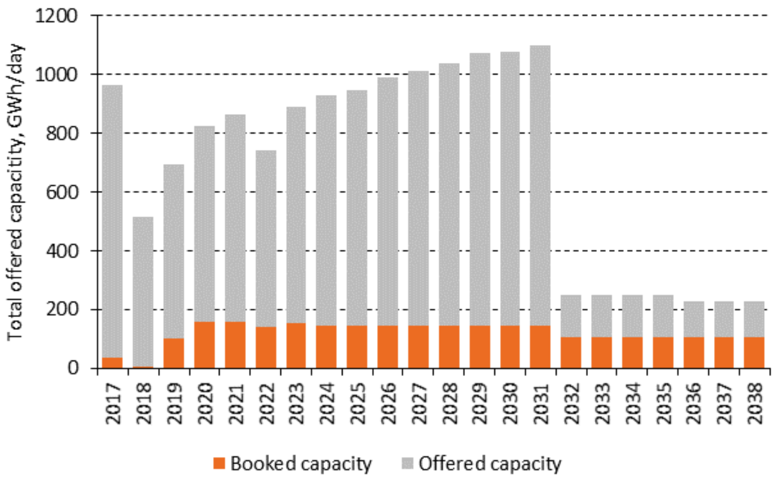

Figure 28: Share of total booked capacity compared to total offered capacities at the Prisma auction, GWh/day

Source: REKK calculation based on PRISMA results

Two-thirds of accepted bids were precisely equal to the offered capacity and the remaining one-third of accepted bids were below the offered capacity. This signals that market players were happy to obtain all the offered capacities, but not willing to pay a premium. It also means that there was no real competition for the capacities, as only one bidder took 100% of the IP's capacity.

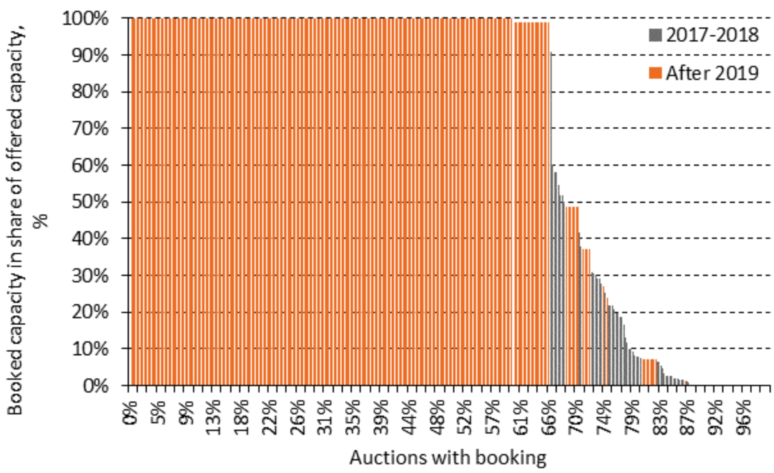

Figure 29: Booked capacities compared to offered capacities in successful PRISMA auctions, %

Source: REKK calculation based on PRISMA results

Timing of bookings

Capacity bookings for 2017-2018 are notably lower than long term bookings. In the 2020-2031-time period, the average booking was 150 GWh/day, while for 2032-2038 bookings averaged 110 GWh/day. For 2017, yearly bookings were only 39 GWh/day, and in 2018 only 6 GWh/day. This implies that long-term (post-2018) bookings are carried out by different market players than those in the near term (2017-2018), which is further corroborated by the geographical location of bookings.

Location of bookings

From 2019 on, only the entry point of Nord Stream 2 and the new and already existing IPs connected to Nord Stream on the gas corridor from Germany via the Czech Republic and Slovakia to Ukraine were booked. This covers multiple IPs but relates to three distinctive borders: the entry of Nord Stream to Germany (RU-DE), the EUGAL pipeline on the German-Czech border (DE-CZ) and the Czech-Slovakian point at Lanzhot.[83] In 2016 and 2017 there are considerably lower bookings on the same IPs: in 2017, around one quarter of the 2020-2030 average bookings were made, while for 2018 only 4% is booked. The geographical pattern is far less concentrated: the 39 GWh/day bookings made in 2017 were made at 20 distinctive points, while the 2020-2030 bookings concentrated on three borders (RU-DE, DE-CZ, CZ-SK) establishing an easy-to-recognise gas corridor. This new gas transmission route was partly financed by the European Union after the 2009 gas crisis to improve diversification and ensure security of supply in Central-Eastern Europe, opening potential trade of new gas sources to compete with the long-term contracted Russian gas.

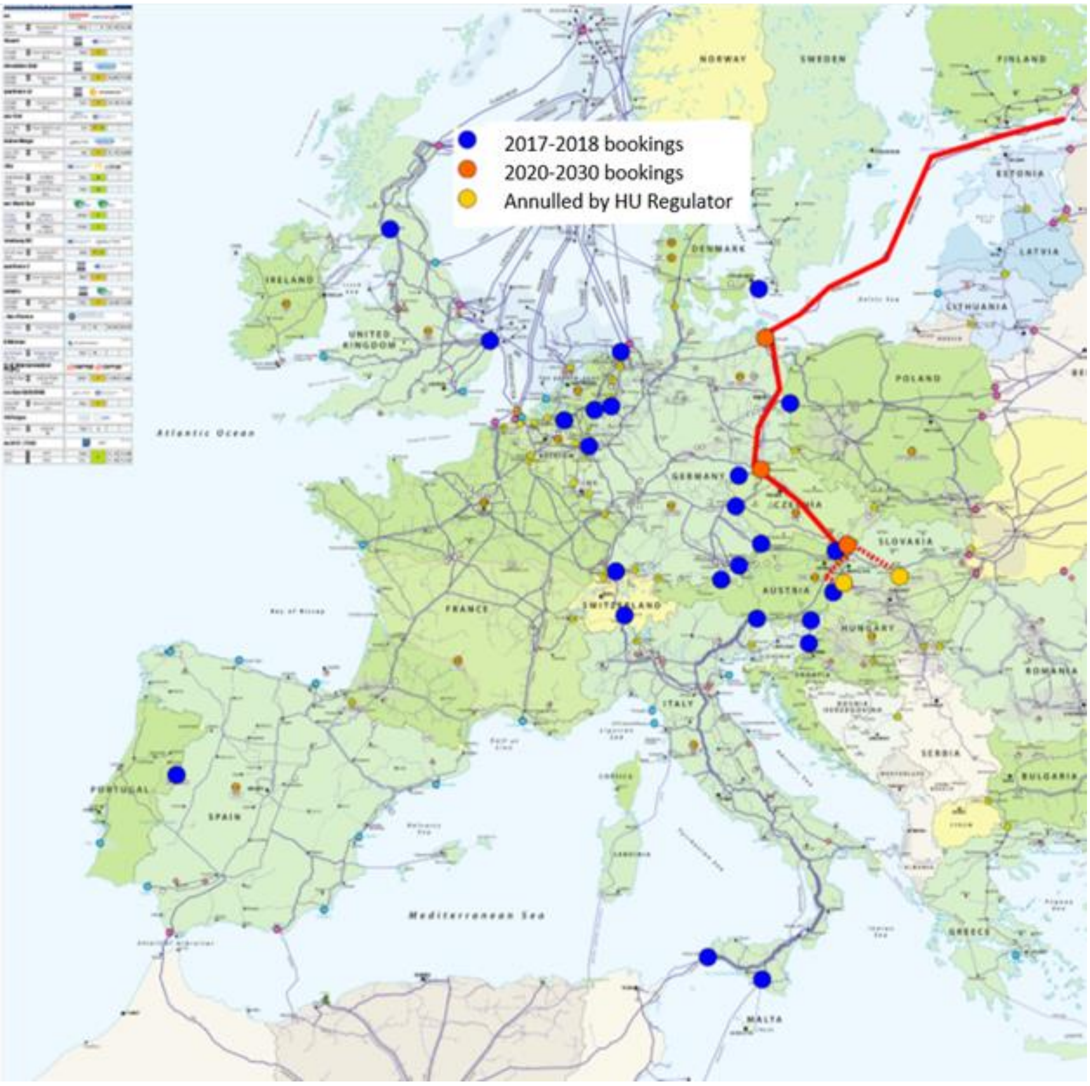

Figure 30: Location of booked IPs in 2017-2018 and after 2020

Source: REKK based on PRISMA, RBP and ENTSOG capacity map

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[83] RU-DE: Lubmin II, Greifswald, Greifswald Entry, Vierow, DE-CZ: Deutschneudorf, Oldbernhau 2, CZ-SK: Lanzhot, Lanzhot 1, Lanzhot 2,

It is worth comparing technical capacity at IPs with offered capacity at the auction. Since PRISMA does not publish the technical capacity at the IPs, ENTSOG transmission capacity maps and network development data were used.

Figure 30 below shows booked capacity against technical capacities on the horizontal axis. The size of the circles indicates the magnitude of booked capacity. According to current capacity allocation regulation in the EU, not all capacities can be booked in the long term, with at least 10% retained for yearly bookings and an additional 10% for intra-year short term bookings. It is apparent that all TSOs complied with this regulation.

Most bookings were made in relation to the future Nord Stream 2, from its planned entry point to subsequent European internal IPs booked at 80% for the 2020-2030 period. For this timeframe, no other IPs were booked at all, which can be explained by midstreamers optimising their portfolio using short-term capacity products.[84] This is underlined by the fact that for 2017-2018 (orange and grey points) different IPs were booked at a much lower share of offered capacity. The preference of market players for the shorter term is reflected by the fact that 2018 bookings are much lower than 2017 bookings. To summarize, for 2020-2030 we find 20% free capacity while on all points in 2017 close to 80% of offered capacities is available for short term trade.

Note, that offered capacity compared to booked capacity on existing European IPs shows a high variance.

[84] This result is supported by ACER's 2016 Market Monitoring Report (MMR): "A comparison with prior MMR results shows however a decrease, on a yearly average, in aggregated technical capacity being contracted and a change in capacity utilisation trends. Shippers increasingly contract capacity for a shorter term to cover needs associated with high seasonal demand (profiling of bookings). In addition, there could be a slight increase in confidence to acquire capacity as CMP measures are gradually applied (i.e., triggering the release of unused capacity). In general, capacity seems progressively more accessible for shippers."

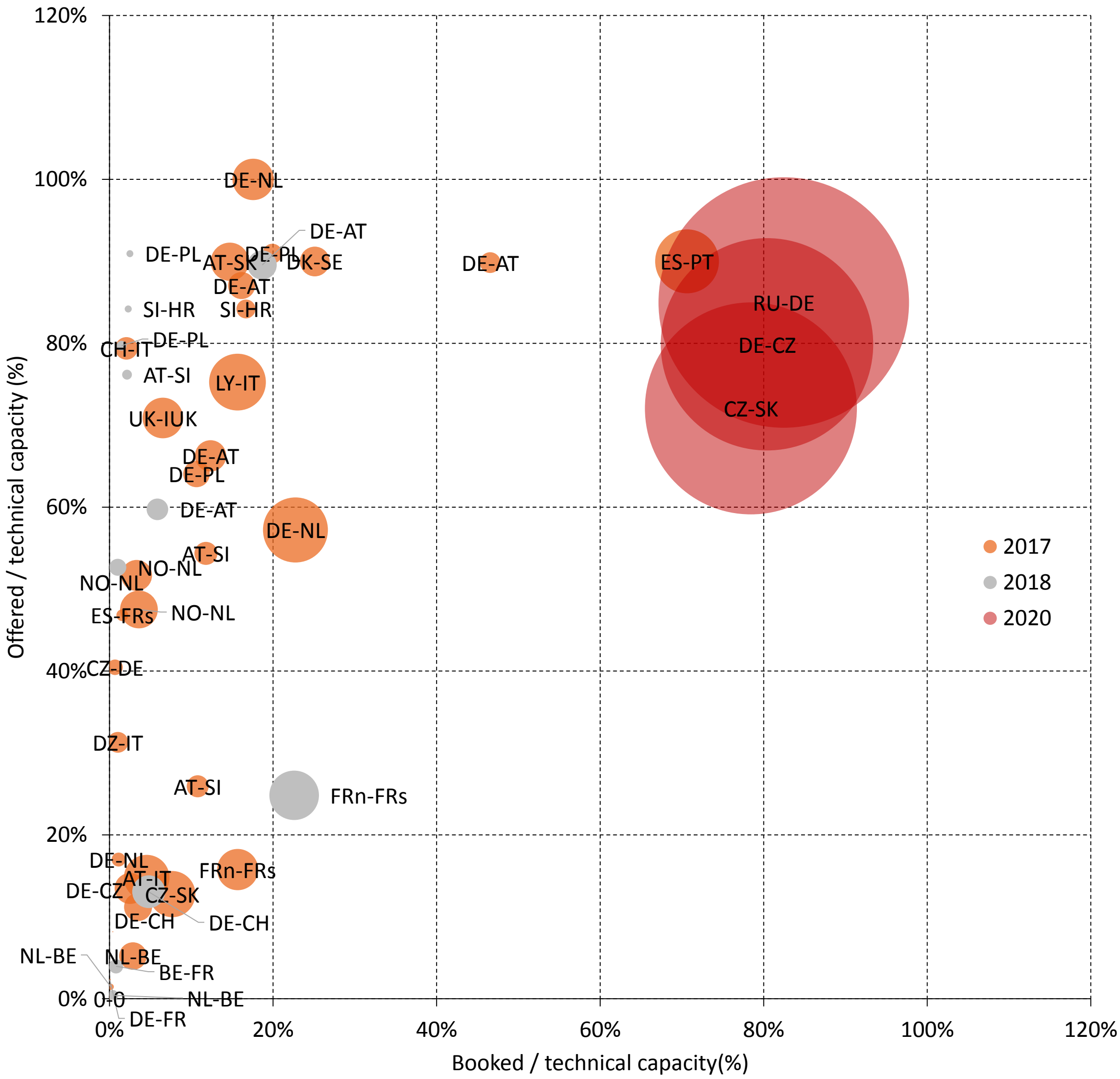

Figure 31: Offered and booked capacity compared to technical capacity in 2017, 2018, 2020, %

Size of circles reflect technical capacity of the IP.

Source: REKK calculations based on PRISMA

On the west-to-east gas transmission corridor analysed above, less than 20% of capacities were booked for 2017-2018 by midstream market participants. This capacity will be available after 2020 for yearly bookings, which could prove problematic for traders that ensure the bulk of their trades with short term deals. The bulk of this gas trade is made by short term bookings, with booked capacity in 2017 making up only 10% of annual European gas consumption (for these IPs there may be already long-term bookings present unreported by PRISMA).

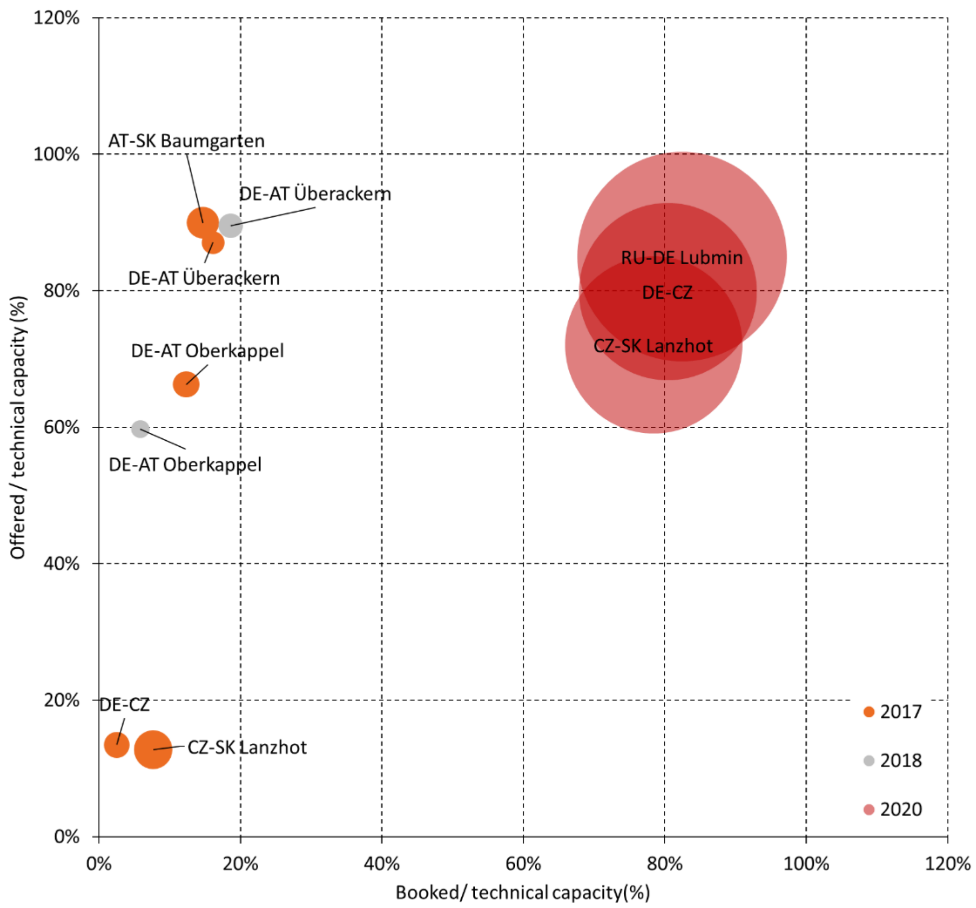

Figure 32: Bookings in 2017-2018 for the highly booked IPs, %

Size of circles reflect technical capacity of the IP.

Source: REKK calculations based on PRISMA

After 2020, 80-90% of capacities offered on the west-to-east gas corridor (entry of Nord Stream, DE-CZ border and CZ-SK border) are fully booked.

Conclusions on the first large scale capacity auction with new capacities on Prisma

Two distinctive patterns for capacity booking can be observed for the 6 March Prisma auctions. In the short term (one to two years period) only a small portion of offered capacities were booked by market players, with a more or less uniform distribution on the European gas grid. From 2019 on,[85] much higher bookings were carried out forming a distinctive route of transport: interconnection points lining up a west-to-east gas corridor after the expansion of Nord Stream to Eastern Europe. The 2017-2018 bookings were likely made by midstream traders active in the European market, while post-2019 bookings were made by Gazprom, its subsidiaries or partners – this is suggested by the pattern of bookings.

The fact that European midstreamers have not at all booked post-2019 means that the Europe’s dominant external supplier obtained these capacities practically without any competition. These capacities should be attractive to midstreamers considering the potential future expansion of Nord Stream and the change of flow patterns in Europe.

[85] The currently active gas transit agreement between Russia and Ukraine expires in 2019.

3.8.3.2 Evaluation of risks related to long-term capacity contracts

Based on the foregoing analyses, we draw the following conclusions on the current and future risks posed by long-term capacity contracts.

LTCs and related transmission and underground storage capacity bookings have a regionally different impact within the EU. In East and South-East Europe, LTCs are still providing monopolistic or quasi-monopolistic long-term gas supply from an incumbent gas producer to local incumbent gas suppliers, and the related long-term capacity bookings sometimes cause contractual congestion. In the meantime, in Western Europe, LT capacity contracts are now seen as the cause for large stranded unused booked capacity.

New long-term capacity is not booked in significant volumes based on booking platforms data. The only exception is the long-term booking of existing and planned infrastructure for the transmission of Russian gas at the March 2017 capacity auction. This has, of course, a significant effect on the eastern part of the EU, where in the Czech Republic and Slovakia, the technical West-East cross-border capacity is largely contracted on a long-term basis in connection with existing Russian LTC shipments and Nord Stream 2.

Contractual congestion due to LT capacity bookings impedes further gas market integration in the EU. However, currently, LT capacity bookings do not pose a general EU-wide problem regarding the availability of bookable cross-border capacity, because much of the long-term capacity booked within the EU is not actively used, especially in Western Europe. Moreover, contractual congestion is expected to lose significance due to the gradual dismantling of legacy commodity and capacity contracts and to the unwillingness of midstreamers to contract new capacity long term.

EU midstreamers' appetite for future LT capacity contracts is fading away. Capacity bookings by them have become more and more short term. Over-contracting and related low-cost cross-border shipping will disappear, and locational spreads adjusted to short-term cross-border tariffs will return.

The competitive situation of midstreamers in a liberalised market[86] is very different from what it used to be. These companies have borne significant losses from previous years, when commodity LTCs were priced above the market prices. Often, the same companies or groups have faced a serious impact from the substantial fall in electricity prices, being large producers, so their financial position has also weakened. Nevertheless, a future possible LT commodity contract priced at market index is not an LTC in the original meaning and does not pose high market-to-market risks anymore. With the assumption of continuous availability of spot gas supplies, midstreamers' motivation to enter into such a commodity contract will be limited and only existent in exchange for some discount on the referenced market price. While reasons for contracting a commodity LTC are limited, even fewer would exist for capacity LTC contracting within the EU. Based on past experience with stranded unused LT capacity booking, it is hard to imagine that midstreamers would be willing to take additional risks and book capacities for the long term, knowing that optimal supply routes can change in the mid term.

In the current situation, we see that long-term booked capacity is usually a sunk cost and has a high negative price impact on the midstreamers who have held it historically. Nevertheless, even as a sunk cost, it offers additional liquidity to the market, as midstreamers can ship gas around Europe for no additional fee (close to zero opportunity cost) and can arbitrage the existent location spreads determined by the short-term capacity booking price. These trading spreads are documented to be now below the respective tariffs.

[86] Without implicit or explicit regulatory or government support.

Producers, who are the largest potential beneficiaries from the possibility to book long term, can use LT capacity bookings for foreclosing competition from their target markets. This raises serious concerns about the justification for long-term capacity bookings on existing infrastructure.

Since market liberalisation and establishment of the traded wholesale markets, the producers do not necessarily need midstreamers. The producers can either sell at the traded market themselves to suppliers servicing the end customers, or they can establish their own daughter companies for the supply of the end customers.

Based on the assessment of the position of a midstreamer, LT capacity contracts are the most attractive for producers. The producers do not need the midstreamers any more as they can deliver themselves at individual trading zones and do not need to have end customers contracted through intermediaries, in contrast to the past when end customers could only be supplied by one local incumbent. Local suppliers can purchase at the local spot/forward market, at prices supplied by the producers at the available location spreads which reflect the transmission tariff.

We assume that capacity LTCs will be either expiring in the coming years or recontracted to actual needs resulting in lower capacity overbooking, making shipping at close to zero variable cost not any more possible. As a result, we expect that the cost of shipping gas around the EU will increase and short-term, physical flow related tariffs will determine the location spreads. If tariffs remain unchanged (in liquid market areas), the location spreads will increase when compared with the current situation.

Considering that producers are the likely holders of LTCs, we can deduce that the new situation with tariff-based location spreads would best benefit LTC-holding producers. They would have the capacity booked in several zones at long-term tariffs[87], which are lower than the short-term factor escalated tariffs. Based on the comparison with alternative market player shipping costs, they would be able to decide into which market and at what costs to deliver.

3.9 Local specifics in regulation and limited transparency

Despite the difficulties, we are seeing more and more convergence, especially in terms of transparency. This concerns the amount of information that TSOs, market operators, trading platforms and other market participants must disclose. On the basis of the published information, it is easier to compare the markets and also have a better understanding of the current local supply situation. This can ease the access to the market for other gas suppliers and strengthen competition. Another benefit for the end customers is the REMIT regulation which targets market abuse, price collusion and other controversial market practices.

Much of the EU regulation aims at simplification and harmonisation of the gas market rules and conditions (as mentioned above) including exception clauses. These allow the local regulators to argue for and keep important local specifics (as in CMP or TAR NC) that present market frictions to efficient cross-border operation and trading.

For example, Commission Regulation (EU) 2015/703 on Interoperability and Data Exchange Rules, Article 16, stipulates that gas quality including odourisation should not constitute an obstacle to cross-border gas flows. Harmonisation of odourisation practices is considered an indivisible part of a PCI project of reinforcement of the interconnection between France and Germany, which was under consideration as of June 2016 (expected commissioning in 2022) and which creates a reverse flow between the countries.

[87] Can be fixed tariff for incremental capacity or under price cap regulation.

In addition, there are obstacles in terms of local specifics and regulatory or even governmental support to some local gas market participants (e.g., TSO, supply incumbent).

In discussions with the stakeholders active in the EU gas market the observation was put forward that the current gas market EU regulation is very much focused on unbundling, market transparency, the TSO responsibilities and the gas market rules. The feedback was that the applicable network codes function more or less well and have helped the market to gain liquidity and become more transparent.[88] Any additional improvements into the content of the network codes may likely not add fundamental market improvements. But there are other areas that mean significant obstacles to the formation of one EU gas market, especially at an individual local level. The individual regulatory authorities as well as the gas market regulations differ from one country to another and also other administrative barriers exist.

The combination of the different shortcomings described above causes the internal gas market to be fragmented, and impacts the local market pricing so that it consequently does not transmit correct market signals and incentives, or it creates additional costs for the market players to bear for accommodating local specifics. Next to the NC implementation differences discussed already in the previous Sections, we mention here several areas and examples of administrative local specifics in regulation and limited transparency:

- A wide range of different regulatory differences in the local markets was identified to exist that constitute market inefficiency. They are defined by local legislation or NRA, and mean additional costs incurred for the energy supply companies. Among the examples of the specific approaches we can mention implementing restrictive market limitations by arguing they stem from the EU legislation implementation, end customer retail price regulation, gas import/export administrative restrictions and restrictive locally specific security of supply regulation adoption.
  - Through stakeholder feedback, we understand that these issues are a sensitive topic for the market participants, though their relevance very much differs from country to country. The impact of the inefficiencies is difficult to quantify, but given the identified examples, we tend to believe, that their negative impact shall be higher in the Eastern EU part. Because they are actively raised by stakeholders we believe they are of significant value, establishing market entry barriers, reducing intensity of local market competition and preserving status quo setup, distorting efficient pricing mechanisms.
  - The newly adopted regulation 2017/1938 concerning measures to safeguard the security of gas supply widens the scope of security of gas supply to a more regional approach, which is a positive development that should reduce the space for individual country specific restrictive security of supply measures in the future. But given this regulation is new and yet to be implemented the extent of its positive market impact is not yet clear.
  - The end consumer price regulation is also a much discussed topic89 for electricity and gas supplies and there seems to be a shift in several countries to abolish or reduce it. Nevertheless in 2015, EC in its Energy Union Strategy reported that household prices remain regulated to a certain

[88] As noted earlier the TAR NC is slightly different in this respect, it is not limited to market rules and deals with tariffs and their regulation. Further, currently it is not yet implemented and market expectations were that it would be somewhat stricter.

[89] In its resolution of 5 February 2014 on the 2030 framework for climate and energy, the European Parliament called for a gradual phasing-out of regulated prices, but taking into account interests of vulnerable consumers.

degree in about half of the countries. As yet, there seems to be no conclusion to this subject.

- Persisting implementation of more strict regulatory parameters into national legislation under the cover of EU legislation implementation (unless provisioned for) nor insufficient local implementation of the EU legislation should not happen now. Nevertheless, if it happens, its correction usually requires considerable time, because it has to be brought to court or to EC attention, before enough pressure on the local government is exercised and such legislation is abolished or amended.

Duration/outlook

- Some of the issues described in this Section are not yet addressed by the current EU gas market regulation and therefore without additional regulatory attention they can prevail or occur also in the future. In particular export/import administrative restrictions do not seem to be addressed currently, nor the end customer price regulation for the vulnerable customers/household segment.

Possible measures

- The most suitable remedy for preventing or correcting market inefficiency stemming from the local regulatory specifics is to support market transparency at EU level to harmonise important regulatory principles also outside the area of market rules. With the increase in transparency, each local difference should ideally be based on disclosed arguments. With the awareness and overview of local barriers in the market, the attention of the stakeholders can effectively push for prioritised elimination of the most striking barriers.
- In our scenario analysis of the EU gas market it will not be possible to reflect individual regulatory specifics and impacts of the existing administrative barriers. Hence we will be forced to abstract from them and stick with their qualitative description.

- An additional group of local market inefficiencies is linked to local specific administrative obligations: local specific reporting duties, local licencing processes and company establishment rules (for example forcing the establishment of local entities for gas trading that make it difficult to bid for coordinated capacity cross-border products).
  - Most of the inefficiencies described under this point relate to transactional costs and market entry barriers, that make it especially for smaller suppliers and traders difficult to have presence in many countries and especially if the local markets are small with limited market opportunities.

  Duration/outlook

  - We expect these inefficiencies to also exist after the current EU gas market regulation implementation, since they are not explicitly targeted by it at present.

  Possible measures

  - To push for supply and trading unit requirement standardisation, enable easy operations of entities across EU borders and reduce or abolish local licencing requirements for supplier or trading entities. In most of the ways the relevant EU gas regulation is already of cross-border scope (network codes, REMIT, MAD, MIFID) so addressing the remaining issues would be consistent if one EU energy market should effectively exist.
  - On the local reporting requirements, we expect that certain reporting harmonisation could be achieved by reducing the regulatory obligations on the market subjects (security of supply) and by regulatory harmonisation,

several of the duties could be also streamlined across the EU market, so the reporting activities would as a result also become standard across the EU.

– Similarly to the previous group of local inefficiencies, they can also increase entry barriers, the transaction costs for operating in the market especially for smaller entities. We will not be able to reflect their impact into the market modelling exercise due to the nature of the general equilibrium market model.

3.9.1 Import & export restrictions

Examples in this Section will be devoted to gas export and import barriers linked with legislation.

The first example of gas import restrictions is the new legislation in Poland. The Legislative Act "O zmianie ustawy o zapasach ropy naftowej, produktów naftowych i gazu ziemnego oraz zasadach postępowania w sytuacjach zagrożenia bezpieczeństwa paliwowego państwa i zakłóceń na rynku naftowym oraz niektórych innych ustaw" (the Polish Act on Petroleum and Natural Gas Reserves) of Article 24a imposes an obligation to hold the required gas supplies (mandatory natural gas reserves) for all participants in the wholesale market, including importers without end customers[90]. The amendment came into force on 1 October 2017. Until this amendment to the previously mentioned Act, companies whose import is less than 100 mcm (before 2011 it was 50 mcm) of gas per year and supply the gas to no more than 100 thousand of end customers were exempt from the obligation to maintain mandatory reserves[91].

The mandatory natural gas reserves can be stored on the territory of Poland or in a third country (EU member or member state of the European Free Trade Association (EFTA)). In the aforementioned amendment is a rule, that compulsory reserves of natural gas outside the territory of Poland meet the following criteria:

- The volume shall be equivalent to at least 30-day average of daily gas imports into the territory of Poland. The gas has to be stored in storage facilities which provide the opportunity to supply the entire volume thereof to the gas system within a period of not more than 40 days.
- Importers ensure that the total volume of the mandatory reserves of natural gas maintained outside the territory of Poland can be delivered to the national transmission or distribution network within the maximum period of 40 days. It means that importers that keep their mandatory reserves abroad have to hold permanent transmission capacity on cross-border connections (interconnectors) and cannot use gas in the UGS for any other purpose.

The fulfilment of the obligation is documented by the Polish regulatory authority (URE). In case of non-compliance, entities may become subject to a penalty of 1 to 15% of the annual turnover of the company concerned.

This obligation to declare mandatory gas reserves even for companies that do not have end customers undermines the wholesale market. While it is understandable that Polish lawmakers wanted to strengthen the security of gas supply to end users, this obligation drives out companies focusing on trading on the Polish market which provide additional liquidity to the market. The measure will likely have an impact on wholesale gas prices which can be higher than in neighbouring countries.

[90] http://isap.sejm.gov.pl/DetailsServlet?id=WDU20170001387

[91] http://isap.sejm.gov.pl/DetailsServlet?id=WDU20070520343+2017%2408%2402&min=1

The second example representing restrictive conditions for importing gas is Italy. Under Article 3 of DECRETO LEGISLATIVO 23 Maggio 2000, n. 164[92], importing entities are required to apply for permits to import natural gas to Italy from the Ministry for Economic Development[93]. A permit is required to import of natural gas by LNG and by pipeline as well. The authorization process is associated with administrative burdens, which consists of the application, including government stamp, and also includes information requirements and information on the subject permits (parameters supplied). Fulfilling this duty takes time and creates a barrier to the market environment, respectively free movement of the gas. For example, imports shall be deemed released if within three months from the request the application is not rejected. Legislation update DECRETO LEGISLATIVO 1° Giugno 2011, n. 93 was in Article 28[94] meant this obligation was mitigated and the request must now be administered by importers who want to import gas to Italy under a contract longer than one year. For deliveries on an annual basis and shorter, importers are obliged to inform the Ministry for Economic Development maximum 30 days before the scheduled start of imports.

As used herein, this process is perceived as a barrier for harmonized conditions of wholesale gas markets across the EU that makes it impossible to generate more common trading areas, which have the high potential for merger. The market conditions for gas import, which are described above, are only applicable on the level of the one nation state.

3.9.2 Restrictive EU legislative application

We see the current natural gas market rules in Romania as a matter of concern. According to amendment (GEO no. 64/2016 z 5 October 2016)[95] to the Energy Act (n. 123 from 10 July 2012), there was re-movement of the obligation for producers primarily to satisfy the need for gas on the domestic market and then eventually to export gas. This could be a good shift. According to Romanian sources, the ordinance was adopted to avoid the "imminent risk" that Romania would be sued at the European Court of Justice and be forced to pay fines for violating EU legislation on blocking gas exports[96]. However, the obligation to trade gas only through a centralized trading platform (OPCOM) controlled by the State-owned market operator has been introduced. This measure justifies the Romanian side by the BAL NC compliance requirements, where the requirement for trade balancing of imbalances in the market is anchored. The measure (trading platform) is defined "in conditions of economic efficiency, based on procedures ensuring the transparent nature of the gas acquisition process and, at the same time, equal and non-discriminatory treatment of persons participating in the gas acquisition procedure as tenderers". However, this measure will probably result in liquidation of bilateral and OTC trades and ultimately to deviation from the standard rules in the EU. It is very difficult for any trading platform to create conditions for the realization of the entire spectrum of different forms of gas trades. Under Paragraph 124 (1e) of the Energy Act the producers must meet the delivery quotas for the supply of

[92] http://www.normattiva.it/atto/caricaDettaglioAtto?atto.dataPubblicazioneGazzetta=2000-06-20&atto.codiceRedazionale=000G0210&queryString=%3FmeseProvvedimento%3D%26formType%3Dricerca_semplice%26numeroArticolo%3D%26numeroProvvedimento%3D164%26testo%3D%26annoProvvedimento%3D2000%26giornoProvvedimento%3D&currentPage=1

[93] http://www.sviluppoeconomico.gov.it/index.php/it/energia/gas-naturale-e-petrolio/gas-naturale/importazione

[94] http://www.normattiva.it/atto/caricaDettaglioAtto?atto.dataPubblicazioneGazzetta=2011-06-28&atto.codiceRedazionale=011G0136&queryString=%3FmeseProvvedimento%3D%26formType%3Dricerca_semplice%26numeroArticolo%3D%26numeroProvvedimento%3D93%26testo%3D%26annoProvvedimento%3D2011%26giornoProvvedimento%3D&currentPage=1

[95] https://lege5.ro/Gratuit/geztaobgge2q/ordonanta-de-urgenta-nr-64-2016-pentru-modificarea-si-completarea-legii-energiei-electrice-si-a-gazelor-naturale-nr-123-2012

[96] http://www.ropepca.ro/en/articole/anre-the-gas-market-for-population-to-be-half-liberalized-as-of-1-april-the-final-price-for-household-consumers-will-continue-to-be-regulated/427/

natural gas to the Romanian internal market. The quotas are set to cover consumption on a regulated market in accordance with ANRE regulations.

The measure about trading platform probably cancels bilateral trading in Romania and also ends trading activities on commodity exchanges (second platform for trading). The official reason for this given by the Romanian government was amending the Energy Act to create a competitive and liquid gas market. In our opinion, this creates the opposite effect.

Commission regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks[97]

Article 3

Definitions

> (4) 'trading platform' means an electronic platform provided and operated by a trading platform operator by means of which trading participants may post and accept, including the right to revise and withdraw bids and offers for gas required to meet short term fluctuations in gas demand or supply, in accordance with the terms and conditions applicable on the trading platform and at which the transmission system operator trades for the purpose of undertaking balancing actions;

The current development in Romania is seen as problematic by the EFET Association, which published a dissenting opinion and mentions a negative impact on cross-border trade[98].

In this case, it is a misleading interpretation of European regulations into national legislation that creates new obstacles or limits the market possibilities of bilateral forward trading. We have not seen any similar interpretations in any other country we analysed, therefore by this misinterpretation of the EU requirements the new local regulation could be interpreted as an effort to make competition in the market more difficult. In order to avoid such unnecessary and market harming deviations, it could prove necessary to draw up uniform and very detailed EU gas market rules as next regulatory steps. But it is not necessarily the only way to go as the EU has several ways and likely enough instruments to enforce the current European legislation.

3.9.2.1 Individual approach to underground gas storages

Underground gas storages (UGS) are a typical example of not using a harmonized approach across Member States. Simply put, each Member State has a specific gas storage model. In some countries the access to storage capacity is regulated, in others the access is provided on market principles. In some countries market prices are determining the storage fees, in some it is up to individual bilateral contracts, somewhere it is listed in official regulated price lists. Elsewhere similar lists are only indicative and in several countries prices are determined in public auctions.

The position of gas storages in the country's gas system is also specific. Somewhere it is part of a virtual trading point, otherwise it is out of the trading point and a payment for the transmission infrastructure, when use the UGS to/from the point of virtual trading point, is paid separately. Furthermore, there are entry/exit points only on a

[97] http://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1505663987425&uri=CELEX%3A32014R0312

[98] http://www.efet.org/Files/Documents/Downloads/170502-EFET-Letter-RO-Gov-New-Gas-Law.pdf

virtual trading point or at the base of UGS or the trading point of a neighbouring country[99].

At the same time, there is a divergent approach to the essence of UGS. In some systems it is perceived as a strategic reserve for power supply, in other countries it is operated purely on a commercial basis. TAR NC also leaves open field in tariffs for using transport infrastructure to UGS or LNG at the local level.

So if we intend to have a better working and more transparent gas market in the EU, we should strive to have greater harmonisation of the UGS role and the model within the EU markets. Based on the current large divergence, we should start at the European level to agree the rules for reserving and using UGS.

3.9.2.2 Licenses for wholesale market

A common barrier to trading on the wholesale market is the requirement for a license from the relevant authority of the country. Currently there are two sub-variants, either a new country license is required, or the entity has to apply for recognition of a license already issued in another country.

For smooth trading options an automatic recognition of a license from another EU Member State could be considered, or it shall not be required to have the license to operate only on the wholesale market (e.g., the Netherlands) without deliveries to end customers. This would require common action by the Member States, for example, by way of regulation act on one side harmonising the requirements on the other side allowing for an EU-wide recognition.

3.10 Strategic role of TSOs, their cooperation and potential consolidation on a future gas market

Currently we can see that in central, western and southern Europe more than one TSO is present in some countries (e.g., Germany, Austria, Italy and France) compared to east Europe where only one TSO per country is established. This corresponds with the history of infrastructure development in the past century, when gas transmission routes from Russia were coordinated and built in east Europe to deliver gas in the requested amount to west Europe by one national gas integrated (usually state) company in the given country, from which transmission functions were subsequently unbundled in the past decade to form one TSO per country.

[99] CEER report on barriers for gas storage product development

Figure 33: ENTSOG members map

Source: ENTSOG

On the other hand, in western EU countries, where several gas sources are or were historically present, we can observe several TSOs in one country which means that in that given country, there were usually several market zones (each TSO had its own market zone). Transmission system development was carried out more on a project to project basis rather than systematic system development. This zone fragmentation did not stimulate gas market development even though there was greater supply competition, on the other hand for each TSO it was easier to calculate capacity on its own, simply structure the network and prepare a development plan. Such TSO diversity can lead to inefficiencies as infrastructure planning motivations may be different or even contradictory, gas flows need not be the most efficient etc., as each TSO optimises its own business results without respective consideration of the impact on other TSOs.

3.10.1 German case

As an example, the German gas transmission system has grown organically over the last decades and now shows a complex system owned and operated by altogether more than 10 TSOs. The transmission system consists of mixed pipelines for domestic supply and large bulk transport pipelines (e.g., NETRA, TENP, MEGAL, MIDAL, WEDAL, OPAL, NEL) connecting important cross-border entry and exit points, storages and domestic offtake points serving as the system's backbone.

Figure 34: Austrian and German gas TSOs

Source: ENTSOG

The entry-exit capacity booking model in Germany was introduced in 2005 by the German Energy Industry Act. A market area refers to a region of the gas network that realizes the entry-exit model, i.e., customers can transport gas independently of the transportation path by only holding suitable entry and/or exit contracts. The obligation to reduce the number of market areas causes the necessity of close TSO cooperation among the numerous network operators active in the German gas sector. TSOs must "*exploit all cooperation options with other TSOs to aim at a preferably small number of networks or subnetworks and balancing zones*" (EnWG 2013, §20(1b)).

The previous fragmentation of the German gas market into 19 market areas was not acceptable for the regulatory authority, so the number of market areas has been drastically reduced. Since 1 October 2011, there have been only two gas market areas in Germany, the NCG and Gaspool. Therefore the gas often has to pass several interconnection points of pipelines owned by different network operators, which are jointly responsible for the organization of the entire transport along the whole transport chain in Germany. "Internal orders" are capacity bookings between downstream and upstream network operators at an interconnection point within a single market area. All network operators are "*obliged to cooperate with one another to a degree which is necessary to enable the transport customer to book only one entry and one exit contract, even if the transport route passes several network systems connected by interconnection points*" (EnWG 2013, §20(1b)). Therefore, "*downstream network operators order from their directly connected upstream network operators firm exit capacity at the interconnection points (internal order) to guarantee the permanent gas supply of end consumers at their own network and in all downstream systems*" GasNZV 2010, §8(3)).

The German gas sector has seen tremendous changes in the last decade. It is expected that the changes will continue due to the German initiative to supply a large share of the energy demand using renewable energy sources (Energiewende). At least during the transformation phase, natural gas will play a major role in the German energy sector. These changes pose big challenges for the TSOs from not only the gas transport point of view but also from the capacity and infrastructure planning.

3.10.2 French case

Since 2003, five mergers have enabled a simplifying of the contractual architecture of the network for the benefit of end users. The French transmission network has moved from seven balancing zones in 2003 to three in 2009. On 1 April 2013, the low calorific gas (L gas) zone was added to the perimeter of the PEG Nord gas exchange point. Since 1 April 2015, the system has been reduced to two marketplaces, including the South Trading Region (TRS), shared by GRTgaz and TIGF, and PEG Nord operated by GRTgaz. The deliberation of 22 May 2014 identified the operating rules of the TRS zone, common to the GRTgaz South and TIGF zones.

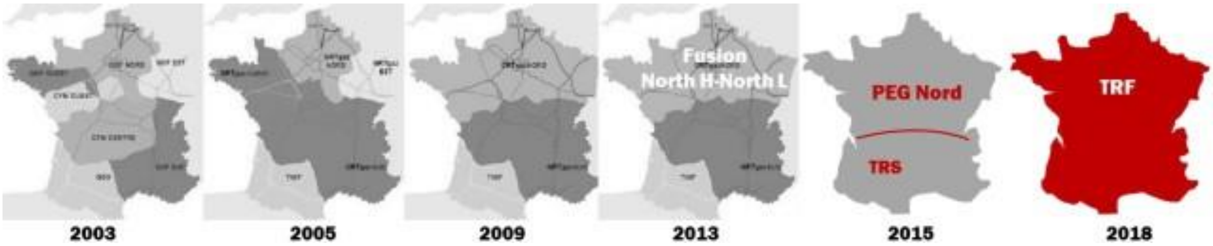

Figure 35: Development of French gas balancing zones

Source: CRE Commission de régulation de l'énergie

The main barrier against the merging of PEG Nord and TRS is physical congestion between these two markets. In 2012, GRTgaz and KEMA investigated different methods for enabling a complete merger of the current market areas, GRTgaz North and South, without having to undertake all of the investments which would be required to avoid all physical congestion in a single market area. Two of the measures which were proposed by the KEMA study were TSO-to-TSO swaps and rerouting of flows; both options may require the revision of existing, or the development of new, operating agreements between GRTgaz and other infrastructure operators.

To reduce a scheduled flow, which would otherwise exceed the technical limits, gas could be swapped with a neighbouring TSO, thus effectively creating a backhaul flow against the original flow. In its effect this mechanism is very similar to counter-trading, but in this case based on an additional exchange between two neighbouring market areas rather than a simple locational swap within a single market area.

In principle, one can imagine two options to implement such TSO-to-TSO swaps:

1. Temporary swap – where the required volume is 'lent' by one TSO to the other for a limited time and returned in kind at a later time, possibly in return for a service fee for the volume and duration of the gas lease; or

2. Firm transaction – where the required volume is sold by one TSO to the other in return for a cash-out payment for the gas itself.

An additional form of resolving the constraints of cross-border cooperation between TSOs could be the re-routing of flows through neighbouring networks. For example, in order to resolve congestion within the French network, an import flow at the French-German border might be reduced, assuming that there are free capacities at the Belgium-German and French-Belgium border as well as within the Belgium and German networks respectively. In that case, the original flow from Germany into France could be (partially) re-routed via Belgium. Within the framework of the entry-exit system, all nominations by shippers would still be 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 ignoring the potential costs of compression, this mechanism could principally be introduced based on an operational arrangement, but without any additional contractual or other arrangements. In fact, the only condition that is really required would be effective cooperation between all TSOs concerned. 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.

3.10.3 Potential consolidation on a future gas market

We do not favour the path of forced ownership change because one owner would not necessarily be an improvement on the current situation. There are several cases across the EU, where several TSO are owned by one owner, but they are in different Member States and operated individually under local national regulation creating no large synergies. Such an example would be Fluxys, where there is no voluntary one owner cross-border TSO merger (or similarly in case of electricity TSOs). Such one (majority) owner TSOs are still operated independently with their local management targets under local regulations. Due to the structure of the TSO business and balance sheets we do not expect significant potential for cost savings if TSO managements or support functions were centralised in company/ownership mergers, we see the crucial point in the assets' operations.

From the discussions with gas market stakeholders we understand that there is a strong push for operational and investment efficiency in the gas market. Hence, next to more strict TSO benchmarking and convergence of national approaches by NRAs we see a possibility to discuss the independent system operator model (ISO) introduction into managing multiple TSO assets. The idea of an ISO that can operate multiple TSO infrastructures (as is the case of Poland), is based on similar principles as proposed in the 3rd package in line with the directive 73/2009.

The establishment of the ISO allows retention of ownership but should also allow a more efficient network system operation over several TSOs. Nevertheless, in the current system, the ownership unbundling of a TSO on a national basis is the highest independence certification standard, so any introduction of a regional or EU-wide ISO would need to be implemented in the legislation/regulation (most likely directive). It would in many aspects resemble the Regional Operational Centre entity introduced by the Winter Package in the electricity sector. For those reasons we expect the ISO model under discussion to be legally viable, even if opposition from TSOs could be expected.

The issues ISO introduction should be able to tackle among others is:

- Increase in efficiency – decisions based on cost minimisation without impact on asset owners profit maximisation
  - determination of optimal gas transmission route inside a zone with multiple TSOs (only the IP with nominations are determined by shippers/traders)
  - determination of optimal gas transmission on virtualised IP with multiple connections
  - determination of optimal interconnection conditions (pressures, timings, gas composition) between TSO minimising the costs across zones/countries
  - operations benchmarking and overview on the same data basis (transparency shall eliminate danger of any unforeseen market cross-subsidisation)
  - potential reduction of overhead costs we see only as a potentially marginal impact
- Identification of sufficient and efficient cross-country investment opportunities

  - analysis and impartial identification of necessary investment increasing operational efficiency or eliminating congestions
  - unnecessary investments not sought when not increasing operational efficiency
- Enhancement of market integration
  - increased incentives for operational market and trading point mergers

By establishment of this TSO operator the efficient management of several TSO infrastructures could be performed at the same time with aligned business goals and motivation to use the provided TSO infrastructure and minimum new investments necessary across several TSOs. The operator could have clear operational cost minimisation targets making sure that the network synergies are used efficiently. The ISO could propose also new investment projects across several countries/zones that would be best investment cost efficient.

Naturally, to make this system useful the evaluation of the benefits would need to be made at a larger zone level in line with adjusted regulation. Local regulatory evaluation could again tend to focus on local optimisation instead of the overall benefits of a larger zone. The benefits and network use cost would need to be allocated back to the TSO providers. The benefits allocation between domestic and transit infrastructure inside a country would be done similarly as in a TCF by an agreed allocation key. The allocation of benefits by zone/country should be available from the ISO evidence, but even if some uncertainty interval existed, the major advantage would be a benefit to all involved zones/countries and how to exactly share it would be a technical issue in the end. An ITO (independent transmission operator) model would not work for the above mentioned purposes, because

i. Its introduction on a regional or EU-wide basis would require ownership changes

ii. It would retain the profit maximisation goal with likely priority over the operational efficiency target.

Again, cost reduction incentives and motivations could be further improved in the next stages of the ISO functioning, nevertheless, individual TSO benchmarking would not be needed as the ISO could report data across several TSOs.

4. THE EFFECTIVENESS OF THE CURRENT REGULATION TO COPE WITH MARKET INEFFICIENCIES

Declining inland gas production, high market concentration in extra-EU gas suppliers to serve EU import needs and occasional access distortions to LNG regasification assets were pointed out as major contributing factors to EU upstream market concentration problems in Chapter 3.

The issue of inland gas production is beyond the scope of this study, but institutional support of EU energy production, especially from renewable resources (e.g. biomethane, power-to-gas) can be one of available mitigation actions aimed at reduction of the EU imports needed.

In response to high market concentration in extra-EU gas suppliers to serve EU import needs, EU policy and regulation have promoted import source diversification and a fully integrated IGM by creating and implementing standardized EU-wide market rules. Ambitious policies to promote renewable energy sources and energy efficiency also put competitive pressure on gas suppliers through reduced consumption. All these are effective measures and part of the EU's current energy and climate regulatory toolkit. However, all of them are non-cooperative meaures in a sense that they do not require cooperation with powerful outside suppliers and operate through exerting competitive pressure on them.

Due to obvious political reasons, much less EU effort has recently been devoted to develop and implement mutually beneficial energy sector reform based on cooperation with its major pipeline suppliers.[100] In particular, the cooperation with Russia almost halted after 2014. In Chapter 6.5 we put forward the concept of an Extra-EU Upstream – EU Downstream Strategic Partnership to promote production and export liberalization in major supplying countries. In Chapter 7 we demonstrate that the potential positive impact of such a Partnership on EU welfare is significant.

In Chapter 3 we demonstrated that LNG has the potential to put continuous and significant competitive pressure on dominant pipeline suppliers and deter them from oligopolistic pricing strategies. However, we also pointed out occasional access distortions to LNG regasification assets (lack of evacuation option; capacity hoarding, distorted regasification tariffs) that might prevent LNG to exert its full competitive effect across the EU.

We think that part of these problems can be effectively addressed by the current regulation. The sensible application of the infrastructure package can help relaxing part of the evacuation constraints for over 100 bcm existing regasification capacity. Third package rules could address occasional access distortions. In addition, we claim that the implementation of an alternative regulatory measure, the Tariff Reform Scenario as proposed in Chapter 6.1 could further help spreading the competitive impact of LNG across the IGM.

4.1 Tariff pancaking addressed by voluntary market mergers and the Tariff Network Code

In Chapter 3 we provided a detailed discussion on the problems the current level and structure of cross-border tariffs create for further EU market integration. In this Section we evaluate to what extent voluntary and bottom up market mergers or the implementation of the Tariff Network Code are effective in addressing these problems.

[100] The notable positive exception is the Energy Community process.

4.1.1 Addressing cross-border tariffs by market area mergers

The fundamental documents of the EU gas target model (GTM 2011 and AGTM)[101] propose and assume overcoming the segmentation of the internal market, caused partly by the applied entry/exit tariffs and related pancaking, by gradual, voluntary and bottom-up market area mergers. According to this view, IP tariffs will be dissolved during full market area mergers, since the creation of a single entry-exit zone leads to the 'loss' of certain interconnecting network points (DNV-KEMA 2013b, p. 15-6).[102] Since this would lead to reduced revenues for one or both TSOs due to the abolished entry/exit tariffs at the former IP, adjustments to the remaining entry and exit tariffs are required. This might take the form of recalculated (increased) tariffs at remaining entry and exit points either for each network separately[103] or for a single (merged) network, occasionally complemented with an inter-TSO compensation (ITC) scheme.[104]

However, the progress of voluntary market mergers is slow and expensive between two and more countries[105]. As described in AGTM, a full market merger entails the merging of virtual trading points and balancing zones of two or more adjacent markets, thus creating a single price zone. The implementation of market mergers therefore requires not only a high level of harmonisation and co-operation but could also create new problems. There is no indication that the bottom-up process will lead to the disappearance of numerous IP points and related entry/exit tariffs in the foreseeable future. Moreover, no provision in the Third Package guarantees this process to be ever completed.

As noted by LECG (2011), large price zones may require the socialisation of significant intra-zone constraints through re-despatch by the TSO if insufficient interconnection capacities are in place. This allocates congestion rents earned by TSOs to shippers and can create distorted incentives that lead to inefficient outcomes. If more congestion costs are socialised, tariffs may increase and become less cost-reflective. Intra-zone constraints would require TSOs to take a greater role in balancing, which is in contrast with the Balancing Network Code that gives the primary responsibility for balancing to individual network users. Also, with a single wholesale price that covers a wider area, signals for investment in certain locations would weaken.

4.1.2 Addressing cross-border tariffs by TAR NC

The main objective of the TAR NC is to create cost-reflective, non-discriminatory and objective transmission access tariffs to minimise cross-subsidization and facilitate cross-border trade. Cross-subsidization should be eliminated between intra-system and transit use and between the users of different entry and exit points. To ensure the termination of cross-subsidization, different indicators are calculated, and tests are performed, that confirm that tariffs are cost-reflective.

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[101] The Gas Target Model was developed in 2011 by the Council of European Energy Regulators (CEER), while the update of GTM 2011 was carried out by the European Energy Regulators under the umbrella of ACER, supported by CEER. For GTM 2011, see CEER Vision for a European Gas Target Model Conclusions Paper, December 2011 (https://www.ceer.eu/documents/104400/-/-/4201834c-3800-66a4-6d4b-042a97367a8b), and for ACER GTM (AGTM), European Gas Target Model Review and update, January 2015 (http://www.acer.europa.eu/events/presentation-of-acer-gas-target-model-/documents/european%20gas%20target%20model%20review%20and%20update.pdf)

[102] The abolishment of an interconnection point could result in a necessary change in delivery point in e.g., a long-term gas supply agreement if that point was named as the delivery point for LTC gas. This development can lead to parallels of the sunset clause type arrangements in the context of mandatory bundling of capacity.

[103] An example was Germany when creating the German market areas into either Gaspool or NCG (DNV-KEMA 2013b).

[104] See the proposal for an entry-exit tariff scheme for a merged Baltic gas market of Estonia, Latvia and Lithuania https://www.sprk.gov.lv/uploads/doc/PCattachmentfinal.pdf

[105] Quicker development in zone number reduction was observed when considering zone mergers within one country (e.g. Germany).

All these rules serve the elimination of transmission tariff distortions. A typical distortion is a high tariff for points where high flows are expected (e.g., long-term contract/transit routes, exit points to "dead-end" countries, domestic exit points). Another important distortion can be defined as market protection: most of the countries "let the gas in" cheaper than they "let it out" of the system. In early 2017 the average exit tariff in EU countries was higher (0.89 EUR/MWh) than the average entry tariff (0.59 EUR/MWh) (including IP tariffs only).

The commodity elements of the tariff are typically paid at the exit points. TAR NC does not set any rules regarding whether commodity-based elements should be added to entry or exit points. However, it states that the charge must be the same at all entry points and the same at all exit points, (thus if a commodity tariff is added to one exit point, then it should be added to all exit points). Commodity based tariffs can be applied to cover costs that are mainly driven by the physical flow volumes (flow-based charge), or to manage revenue under- and over-recovery (complementary revenue recovery charge - CRRC) - similarly to rescaling, (see later). CRRC, however, can only be applied on non-IPs.

		AT	BE	BG	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	NL	PL	PT	RO	SE	SI	SK	UK
Commodity fee to be paid at	Entry		x									x			x	x										x	x
	Exit		x		x		x					x	x	x	x		x				x	x	x		x		x

Table 9: Commodity based tariff components on top of capacity-based tariff in EU countries

Source: REKK calculation based on TSO and NRA data available in August 2017

The promotion of cost-reflective tariff calculation is a key element of TAR NC. The capacity weighted distance related (CWD)[106] methodology is to be used as a benchmark. NRAs can apply other methodologies, but their results should be compared to CWD tariffs and the differences explained and justified. Tariffs and their comparison to CWD tariffs and the related justifications will be monitored by ACER.

Under the TAR NC, NRAs have significant discretion over several components of the applied tariff calculations. TAR NC provides only ranges for short-term multipliers and seasonal factors, although in the case of the latter, the expected distribution of bookings should be considered. Exclusive discounts are granted to storage facilities: at least 50% (to avoid double charging), but even more is acceptable if justified, except for those storage facilities which allow for 'cross-system' use and thus compete directly with an IP (connected to at least one other TSO or DSO). Tariffs at network points relevant for increased security of supply can also be discounted – such as entry points from LNG regasification terminals, or the only entry point to "dead-end" countries. Furthermore, NRAs can use three adjustment techniques: benchmarking implies that the reference prices are adjusted at an entry or exit point so that the resulting values meet a competitive level. Equalisation offers the possibility of applying the same reference price to some or all points within a homogeneous group, while rescaling can consider the profits and losses of the last few years, and tariff levels could be adjusted accordingly.

4.1.3 TAR NC implementation is not sufficient to remove pancaking

Due to the accelerating expiry rate of legacy LTCs from 2019 onwards, decreasing capacity bookings and gas flows might put an upward pressure on IP tariffs at several interconnectors. At the same time the likely negative investment in the gas transmission networks[107] across the EU will put a downward pressure on IP tariffs. While the combined

[106] In previous versions there were six different reference price methodologies presented in detail, from which NRAs should have applied one as the basis of their tariff calculation.

[107] Depreciation exceeding the amount of new investments.

impact of these changes on individual IP tariffs will vary largely across the EU, the forecasting of these changes is beyond the scope of this study.

Regarding outlier high tariffs, we already see an adjustment process ongoing, partly due to TAR NC implementation expectations. Another possible explanation could be the better functioning of short-term markets lately: a large part of the TSO's revenue comes from short-term products, so the price of the yearly products (used in this calculation) can be lowered. In some countries cost revision can also explain part of the tariff changes. "Tariff competition" in the case of competing transmission routes might have also contributed to decreasing tariffs in the CESEC region in the last two years (Figure 36).

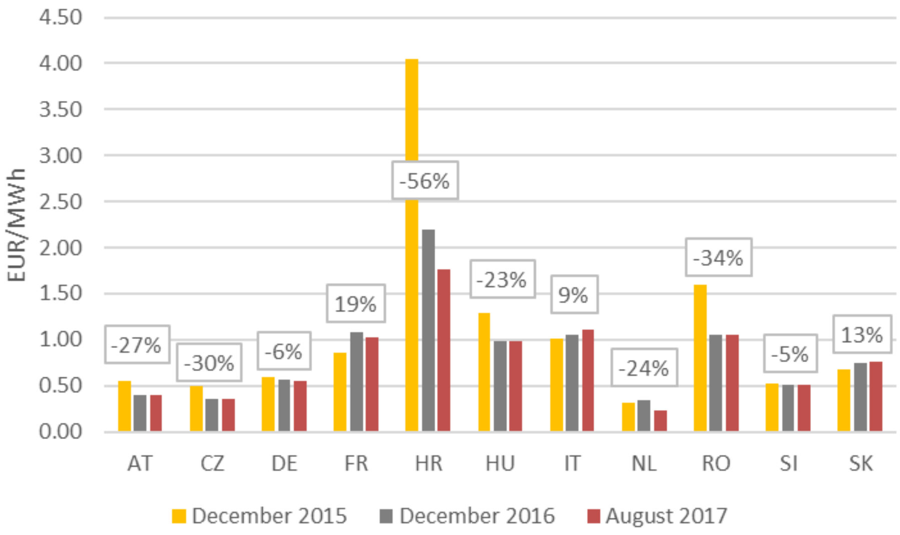

Figure 36: Evolution of IP tariffs in the CESEC region and in some other European countries (shown as a benchmark)

Note: Percentage shown is the change from December 2015 to August 2017

Source: REKK calculation based on TSO and NRA data, latest information available in August 2017

Based on the previous discussion, we expect that the most likely outcome of TAR NC implementation will be a significantly increased transparency of transmission related costs and tariff setting practices by TSOs and NRAs and the stabilization of present IP tariff levels with a parallel cut back of high outlier tariffs in the coming years. For both EU entry and exit the highest 15% tariff is expected to be cut back to the maximum of the remaining tariffs. We will use this assumption when formulating the Reference Scenario for gas market modelling (see Chapter 5).

4.2 Physical, regulatory and contractual constraints to network access

Besides cross border tariffs, Chapter 3 identified and analysed different constraints to network access as significant trade barriers with a potential to explain remaining wholesale price differences within the EU.

In this Section we ask the question of how effective the present regulation is in addressing the inefficiencies caused by the following network access constraints:

- Lack of interconnection between neighbouring market zones
- Uni-directional interconnections
- Physical congestion
- Third party access exemptions

- Contractual congestion
- Market foreclosure by long term transmission capacity contracts

Our main objective is to identify those significant inefficiencies where alternative regulatory proposals might be justified and further investigated.

4.2.1 Lack of interconnection and the infrastructure package

Lack of infrastructure connecting neighbouring market zones is rare in the EU. Moreover, Regulation 347/2013 on the guidelines for trans-European energy infrastructure and the related PCI selection and implementation process explicitly addresses this issue. Connected regional initiatives for the most affected regions are operational and effective (CESEC for the Central and South East European region or South GRI for Iberian Peninsula and France) and simultaneously, PCIs support regional cooperation within transmission corridors (BEMIP Gas for the Baltic region - Priority Corridor Baltic Energy Market Interconnection Plan in Gas, SGC - Priority Corridor Southern Gas Corridor, NSI East Gas - Priority Corridor North-South Gas Interconnections in Central Eastern and South Eastern Europe and finally NSI West Gas - Priority Corridor North-South Gas Interconnections in Western Europe).

We therefore conclude that the issue of missing gas infrastructure for completing the IGM is sufficiently addressed by the present regulation.

4.2.2 Uni-directional interconnections and the supply security regulation

The ability of major transmission pipelines to work in bi-directional mode can improve gas supply security and encourage competition simultaneously.

The supply security related feature of bi-directional capability of transmission was demonstrated during the January 2009 Russia - Ukrainian gas crisis. At a time of failure of the traditional routes for supply to individual areas, this element of the infrastructure was essential to provide continued gas supply. Hence, Regulation 994/2010 on the security of gas supply put forward an obligation to enable bi-directional capacity on all major EU gas transmission pipelines where this was technically and economically feasible.

While the implementation of firm physical reverse flow capacities intends to serve primarily security of supply purposes in (rare) crisis situations, their presence can also enhance gas-to-gas competition in the following ways.

- The transactions (both physical and contractual) made possible by bi-directional capacities change the gas trading landscape under normal market conditions. For example, the implementation of numerous bi-directional firm capacities in CEE supported gas-to-gas competition to take effect in this region, resulting in the convergence of Czech and Slovak wholesale gas prices to German price levels.
- The availability of bi-directional capacity at major interconnection points could enhance the possibility to evacuate LNG from certain locations (e.g., LNG from France towards Germany and from Greece towards Bulgaria).
- Finally, transportation routes made available by the implementation of bi-directional capacities might create alternatives to physically or contractually congested routes and thus reduce congestion related costs.

Note that newly implemented physical reverse flow capacities threaten the market position of incumbent wholesaler companies in the relevant direction in almost all cases. This might partly explain the considerable number of exemptions to the obligation to enable bi-directional capacity that have been granted under Article 7 of Regulation 994/2010, despite the moderate early cost estimates for such investments by GTE.[108]

Since the newly adopted Regulation 2017/1938, replacing the former gas supply security regulation and especially its Annex III contains detailed rules regarding the obligation to enable bi-directional capacity and to receive exemption to that obligation in the future, we disregard from the further regulatory analysis of this issue in the remaining of this study. However, in Chapter 7 we will present an estimate for the price and welfare impacts of implementing 100% availability of bi-directional capacity for each existing EU internal IP in the 2020 Reference Scenario.

4.2.3 Physical congestion management

Physical congestion happens on a piece of transmission infrastructure when the ratio of physical flow to available firm technical capacity gets very close to or exceeds[109] 100%.

Physical congestion on the EU transmission grid is quite rare today and is not considered as a major source of market inefficiency by market participants.

The technical capability of the European transmission grid to serve load in security of supply stress situations has been analysed by ENTSOG modelling and by the European Commission (EC) recently. The conclusion of the analyses is that certain network limitations can be found both in Western Europe (e.g., connection between France and Germany) and in Eastern Europe (e.g., the connection of Bulgaria with Romania or Greece), but at present physical congestion is not an EU-wide issue in this regard.

With respect to physical congestions related to the present commercial use of the EU grid, ACER identified only 8 critical IPs in 2016.[110] The actual problem of physical congestion is limited to some of the regions with insufficient infrastructure and to countries which implement a high-level zone approach to promote price and market convergence. Our own analysis in Chapter 3 concluded that physical congestion might have significantly contributed to wholesale price differences within the EU at two interconnections (AT-HU, DE-AT) in 2015-16.

The problem of physical congestion can be mitigated:

- By the application of the CAM NC auctioning mechanisms
- By improved efficiency in using the existing infrastructure
- By the construction of new infrastructure

By principle, regulatory measures to improve network use efficiency are preferable to costly investment in new infrastructure in addressing the problem of physical congestion. For example, the moderate overall utilisation level of the existing, meshed EU grid[111] provides for several potential alternative transportation routes to congested ones. We think that part of the physical congestion problem today is caused by inefficient cross-border IP tariffs that make existing alternative-to-congested physical transportation routes commercially uncompetitive (e.g., the case of the DE-AT border). Our related hypothesis is that the implementation of the Tariff Reform Scenario, proposed in Chapter 6.1, will ease physical congestion on the EU grid.

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[108] GTE+ Reverse Flow Study. Technical solutions. 21 July 2009. http://www.gie.eu/index.php/publications/gte/gte-plus/reverse-flow

[109] The availability of interruptible capacity can explain such a situation.

[110] ACER 2017 Implementation Monitoring Report on Contractual Congestion at Interconnection Points, http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%202017%20Implementation%20Monitoring%20Report%20on%20Contractual%20Congestion%20at%20Interconnection%20Points.pdf

[111] About 60% of firm technical capacity is booked for the gas year 2017/18.

Nevertheless, new infrastructure and reverse flow projects are being built or planned to address physical congestion within the framework of the PCI selection and implementation process. The incremental capacity procedure of CAM NC and the obligatory infrastructure standards of the Security of Gas Supply Regulation further promote this process.

We conclude that the issue of missing gas infrastructure both to complete the IGM and to address physical congestion on the EU grid is sufficiently addressed by the present regulation, including the infrastructure regulation and CAM NC, and also that the amount on new necessary infrastructure is limited.

Interconnection points within countries

A separate issue is the congestion at interconnection points within countries. This arises for example in France, namely Liaison Nord-Sud, Exit GRTgaz, which announced plans to merge its zones. Due to the insufficient infrastructure available in France for a functioning zone merger, additional new infrastructure will be built to reduce the congestion problem. There is a risk that the costs of the merger will increase the cross-border tariffs of France, thus increasing the trade barriers to enter the French market.

Germany has recently decided to merge its two trading zones by 1 April 2022. The cost of bottleneck removal was estimated at EUR 3 billion in 2013 for Germany and the total benefit was estimated at EUR 57 million for the first year of the merger by TSOs[112]. Regarding the possible costs and benefits, the authors of the proposal were not too specific. An expected additional cost of the zone merger of EUR 395 million was mentioned, which is just a fraction of the original sum expected by the TSO in 2013, and it is expected that part of the cost would be realized in the same way regardless of the possible merger of the zones. The quantification of the potential benefits and their allocation among zones[113] and stakeholders is missing. According to the authors of the proposal of the zone merger, the result will lead to increased liquidity, which will strengthen the German wholesale market.

In France and Germany, this objective will be achieved only by completing the infrastructure. Here it is confirmed that in some cases no regulatory measure will help (such as CMP) and costly measures in the form of new infrastructure must be used.

However, the inefficiencies inherent in explicit auctions (i.e., bookings for both directions for the same time period are common) would justify further analysis into the feasibility and the potential benefits of implicit auctions e.g. for day-ahead capacity allocation.

4.2.4 Third party access exemptions

TPA exemptions are regulatory concessions provided by the European Commission, based on Article 36 of Directive 2009/73. TPA exemptions aim to support new infrastructure development financing. They restrict the use of newly built infrastructure by third parties for the benefit of the original contracting parties.

Within the EU, there are several infrastructure projects that are exempt from the TPA rule based on Article 36 Directive 2009/73 of 13 July 2009. They can be divided into already existing and planned infrastructure. The already existing pipelines include the OPAL gas pipeline in Germany, the Gazelle pipeline in the Czech Republic (22 years until 1 January 2035), the BBL interconnector between the UK and the Netherlands (particularly until December 2022) and a few LNG terminals. There are several

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[112] https://www.icis.com/resources/news/2013/03/20/9651776/german-regulator-erases-hope-of-ncg-gaspool-natural-gas-market-zone-merger/
[113] With the north-south flow prevailing, wholesale price increase for Gaspool zone could be expected.

exemptions to pipelines under construction such as TAP or planned such as Poseidon.[114] These exemptions in the EU infrastructure network are currently not considered problematic with the notable exemption of the OPAL pipeline.[115]

We are of the opinion that TPA exemptions will not play any major role in the future as we do not expect any key infrastructure project to apply for or be granted an exemption considering the respective conditions and the CAM NC rules for incremental capacity process. We conclude that TPA exemptions currently do not imply serious market inefficiencies, therefore we do not propose to further investigate additional regulatory measures in this regard.

4.2.5 Contractual congestion management

The combination of high capacity booking levels and low utilisation rates for booked capacity results in contractual congestion with the potential of foreclosing other market participants from using otherwise unused technical capacity at some interconnection points.

Recent ACER analysis and our own assessment in Chapter 3 suggest that the threat of contractual congestion and the related risk of market separation and inefficiency is real, at least in the mid-term in the EU. There are several pipelines where bookings exceeded 95% of the technical capacity with no physical congestion occurring. We identified five borders where contractual congestion contributed to wholesale price differences in 2015-16.

Contractual congestion, during time periods without physical congestion, is tackled through the congestion management procedures laid down in the CMP GL. These procedures include a possible oversubscription and buy-back mechanism. Another mechanism to mitigate contractual congestion is the Firm Day-Ahead Use-It-Or-Lose-It (FDA UIOLI) system. These procedures were expected to at least partially alleviate contractual congestion at cross-border interconnection points. Nevertheless, national regulators have the discretion in choosing the applied CMP method, and hence these can differ on each side of the interconnection point. Further, the more the market-based method of oversubscription and buy-back is applied, the more effort and risk is placed on the TSO. Without a proper motivation for the TSO, their application of the method would be the conservative FDA UIOLI.

According to ACER, FDA UIOLI mechanism is applied at 13 of the 23 IPs found to be contractually congested. Most of the reported FDA UIOLI offers - both in total numbers and capacity amounts – occurred at the borders of NetConnect Germany, which encompasses more entry and exit IP sides than any of the other two market areas (Gaspool and Austria) where FDA UIOLI was applied in 2016. At the remaining 10 contractually congested IP sides, the respective NRAs shall require the relevant TSO(s) to implement and apply the FDA UIOLI mechanism or show that the congested situation is unlikely to reoccur in the following three years. These IP sides have not implemented Oversubscription and Buy-Back rules either; according to ENTSOG data, there was no capacity made available via any of the CMPs in 2016.[116]

The number of congested IP sides for which secondary capacity was traded remained relatively low (7 out of 23; most trades were concluded for the AT-HU and for one of

[114] https://ec.europa.eu/energy/sites/ener/files/documents/exemption_decisions2017_0.pdf

[115] Poland strongly opposed the October 2016 decision of the EC to allow Gazprom to bid for the remaining 50% of OPAL capacity alongside third parties at auctions organised by the PRISMA platform. See details on the related arguments and the final decision of the CJEU:
https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/09/The-OPAL-Exemption-Decision-a-comment-on-CJEU%E2%80%99s-ruling-to-reject-suspension.pdf

[116] According to the Czech and Italian NRAs, the FDA UIOLI is applicable at specific Czech IP sides since the beginning of 2017 and at specific Italian IP sides since April 2017.

the DE-CH IPs). Congestion management procedures have yielded additional capacity offers only at the borders of 7 Member States in 2016; no application of the Long-Term Use-It-Or-Lose-It (LT UIOLI) mechanism has been reported to ACER. We conclude that the non-application of the LT UIOLI is a result of (i) restrictive conditions set by the CMP (Article 2.2.5), which stipulates that an average use of more than 80 % of the capacity prevents potential application of the LT UIOLI, and (ii) of the requirement of long-term booking demand for the capacity to be released, so that a negative impact on TSO revenues is prevented. Oversubscription was applied in three Member States, but almost all additional capacity amounts were offered on the Dutch IP sides.

We conclude that the observed contractual congestion is mainly due to the large amount of legacy LT capacity bookings and a simultaneous poor implementation of the CMP GL mechanisms. We assume that more efficient deployment of the existing tools, together with the likely phase-out of the contractual congestion problem due to reduced future LT capacity bookings will be sufficient in addressing this risk.

Therefore, we do not propose additional regulatory measures strictly in this regard. However, the implementation of the Combined Capacity-Commodity Release Scenario (see Chapter 6.4), primarily addressing the issue of market foreclosure, could also improve market conditions with regard to reduced contractual congestion related risks.

4.2.6 Market foreclosure by long term transmission capacity contracts

A significant risk that LT capacity contracts pose for efficient market functioning is that they might permanently restrict access to key supply routes for alternative suppliers or producers. In Chapter 3 we discussed recent developments in capacity bookings and delivery point choices to argue that this is still a valid risk for the IGM.

The Third Package adopted in 2009 prohibited the application of destination clauses to relax the strict market segmentation created by the legacy LTCs.

Producers responded by triggering some modification of the contractual terms so that long term transmission capacity booking received a crucial role in blocking competition and preserving market foreclosure. In some cases, deliveries were moved closer to the target countries, selling at the VTP or at the border. Physical delivery can prevent cheap swaps and makes it more expensive to resell the gas in countries with more attractive market conditions. An example of this is when Gazprom renegotiated the delivery point of the Italian LTC from Austria to the Italian border. In other cases, redirecting of the LTC flows aimed at blocking competition. One example is Hungary, where a third of the LTC deliveries were shifted from the Ukrainian entry point to the Austrian hub. As a result, LTC volumes are transmitted on the usually congested AT-HU interconnector, which is one of the main routes for the spot traders to Hungary and the CEE region. These examples highlight the importance of long term capacity bookings in maintaining market segmentation within the EU.

A similar strategy emerged from the March 2017 capacity auction in connection with the Nord Stream 2 pipeline, where Gazprom booked long term the most important existing trading routes from Germany to the Czech Republic and Slovakia, previously used by the spot traders and also contracted for new incremental capacity on this route. Due to its outstanding importance, we provided a detailed assessment on the outcomes of the 2017 March Prisma auction in Chapter 3.

4.2.6.1 Existing regulatory measures are insufficient in addressing the risk of market foreclosure by LT capacity contracts

CAM NC unified the conditions for transmission capacity booking EU-wide. It established robust rules for booking cross-border capacities, both on a yearly and on shorter term basis (down to daily) and new products of bundled capacity. CAM NC also introduced a booking platform, through which it is possible to reserve cross-border capacity in a bundled form. Following the CAM NC, all interconnection points are auctioned transparently and in a simpler way, i.e., single purchase for bundled capacity and single nomination. Technical capacity is maximised through joint TSO capacity calculation. Furthermore, secondary trading of capacity is enhanced, and additionally reverse flows encouraged and interruptible capacity pricing standardised. Currently, there are three platforms (PRISMA, GSA and RBP), with only one at each cross-border point. According to the CAM NC Implementation Monitoring Report, the unbundled capacity was still offered for cross-border points where no more bundled capacity was available.

CAM NC addresses the risk of market foreclosure resulting from long term capacity bookings. Paragraphs 8 and 12 of the recital to the Regulation emphasizes that the capacity allocation mechanisms should be designed in such a way as to avoid the foreclosure of downstream supply markets. However, the Regulation is silent about the meaning of foreclosure and has not much to say about how to prevent capacity bookings to foreclose downstream markets. It obliges TSOs to reserve 20% of their technical capacity for shorter term bookings (10% for maximum 1 year, 10% for maximum 5 years)[117] and puts a 15 years limit on the length of possible capacity booking on annual yearly auctions.[118] It urges national regulators to increase actual reserved capacities for shorter term bookings at certain critical interconnection points.[119]

It is paragraph 6 of Article 2 of CAM NC Regulation that is the most explicit on how to address the risk of foreclosure of downstream supply markets:

"In order to prevent foreclosure of downstream supply markets, competent national authorities may, after consulting network users, decide to take proportionate measures to limit up-front bidding for capacity by any single network user at interconnection points within a Member State."

This Section provides for a very broad authorization, but no obligation, for national regulatory authorities to limit up-front the participation of certain network users in bidding for specific capacities or to limit the share of capacities a single network user might receive at the auctions.

We conclude this brief regulatory review by noting that nothing in CAM NC rules out the possibility that extra-EU gas producers or their affiliates book significant amounts of existing and new capacity for the long term (up to 15 years) on intra-EU interconnectors in upcoming capacity auctions. The first experience with the application of CAM NC provided a stark example of potential market foreclosure by long term capacity bookings by an extra-EU producer.

We conclude that CAM NC in its present form is unable to effectively address the risk of market foreclosure by long-term capacity bookings. Therefore, we propose additional regulatory measures in this regard in Chapter 6.

4.3 Conclusion

To more effectively address high upstream market concentration, the EU could:

- Intend to reduce the general gas import dependence

[117] Article 6 and 8 (6-8)
[118] Article 11 (3)
[119] "The exact proportion of capacity to be set aside in relation to paragraphs 6 and 8 shall be subject to a stakeholder consultation, alignment between transmission system operators and approval by national regulatory authorities at each interconnection point. National regulatory authorities shall in particular consider setting aside higher shares of capacity with a shorter duration to avoid foreclosure of downstream supply markets". Article 8 (9)

- Consider the removal of intra-EU transmission tariffs to further help spreading the competitive impact of LNG across the IGM
- Consider a cooperation framework to promote production and export liberalization in major supplying countries

Regarding the current level and structure of cross-border tariffs we conclude that neither the market merger process nor the TAR NC implementation process seems effective in addressing the pancaking problem they create. The most likely outcome of TAR NC implementation will be the stabilization of present IP tariff levels with a parallel cut back of high outlier tariffs in the coming years. This leads us to propose an alternative regulatory scenario, called the Tariff Reform Scenario, in Chapter 6.

On physical, regulatory and contractual constraints to infrastructure access our most important conclusion is that CAM NC in its present form cannot effectively address the risk of market foreclosure by long-term capacity contracts. Therefore, we propose:

- As a minimum, stand-alone measure to amend paragraphs 6 and 7 of Article 8 of Regulation 2017/459 to increase the share of existing technical capacity that TSOs are obliged to set aside and offer for auctioning for yearly or shorter durations to 50% or more. The same approach of increasing the share of yearly or shorter durations from 10% to 50% should also be considered for incremental capacity within the EU to prevent future market foreclosure.
- To consider an alternative regulatory scenario, called the the Combined Capacity-Commodity Release Scenario (see Chapter 6.4) to boost network use efficiency EU-wide and improve market liquidity in regions with low market liquidity and high market concentration.

Regarding all other network access constraints (third party access exemptions; lack of interconnection between neighbouring market zones; uni-directional interconnections; physical and contractual congestion) we conclude that the (improved) implementation of existing regulations can effectively address them.

Nevertheless, to improve the efficiency of cross-border capacity allocation we suggest further analysing the potential benefits of introducing implicit day-ahead auctions in the future. The idea of implicit market coupling on day-ahead basis and its discussion is part of the Conditional Market Merger scenario in Chapter 6.3. However, since the EGMM algorithm works as if implicit market coupling was already implemented within the EU, we do not include this proposal for further quantitative welfare analysis.

Finally, Table 10 summarises the process we went through from identifying market inefficiencies to formulating alternative regulatory proposals (see Chapter 6). It also includes the major conclusions we draw from the analyses in Chapters 3 and 4. Firstly, we identified the likely causes of inefficiencies (column 3) and then asked to what extent existing Third Package related regulations can effectively address the causes of inefficiencies (column 4). Column 5 contains the major alternative regulatory scenarios we identified, from which those that are indicated with green were selected for quantitative welfare analysis (see Chapter 7).

Table 10: From inefficiencies to additional regulatory measures.
*Colours: * Effectiveness of current regulation to address inefficiency indicated by colour: green - sufficient; red – insufficient; ** Green: additional regulatory measure selected for quantitative welfare analysis*

	Inefficiency description	Potential causes	Existing measures*	Potential additional regulatory measures considered and selected**
Product market	1. Upstream market concentration at the EU level	Declining inland gas production	Beyond scope	n.a.
		High market concentration in extra-EU gas suppliers to serve EU import needs	Diversification, competitive IGM framework, demand redicing policies (energy efficiency, RES)	**Strategic Partnership concept** (promoting production and export liberalization in major supplying countries)
		Occasional access distortions to LNG regasification assets (lack of evacuation option; capacity hoarding, distorted regasification tariffs)	Infrastructure package (evacuation); regulatory oversight	**Tariff Reform Scenario** can help spreading the competitive impact of LNG across the IGM
	2 Upstream market concentration at the member state level	Market protection by distorted IP tariffs	Further promoting market integration by CAM NC, TAR NC and CMP implementation	**Tariff Reform Scenario** (IP entry-exit tariffs set to zero and a simultaneous establishment of a TSO Compensation Fund (TCF))
		Market foreclosure by long term IP capacity booking by the dominant supplier		**Combined Commodity-Capacity Release Scenario** (a simultaneous increase up to 50% in the share of short term transmission capacities for both existing and new infrastructure and an obligation for gas producers/importers to sell at least 50% of their gas at the nearest VTP to their entry into the transmission grid on EU territory)
				Full EU market merger
				Voluntary Trading Zone and Conditional Market Mergers
Network access	3. Current level and structure of cross-border tariffs	Current cross-border entry/exit tariffs and related pancaking as trade barrier	Voluntary market mergers; TAR NC	**Tariff Reform Scenario** (IP entry-exit tariffs set to zero and a simultaneous establishment of a TSO Compensation Fund (TCF))
	4. Physical restrictions	Missing interconnectors to end isolation of market zones and evacuate LNG (Iberian Peninsula, Greece, Poland)	The infrastructure package, the related PCI/CEF process and regional initiatives (BEMIP, CESEC) are sufficiently addressing the lacking infrastructure issue	Regional Operation Centres (ROCs) with mandate to implement PCI infrastructure
		Often lacking bi-directional firm capacities as trade barrier	Gas SOS regulation; too many exemptions	Full bi-directional firm capacity obligation
		Physical congestion	Sufficiently addressed by the infrastructure regulation and CAM NC	**Tariff Reform Scenario** can help opening up alternative-to-congested transportation routes
	5. Regulatory and contractual restrictions	Exemptions to regulated TPA	Third Package	No TPA exemptions
		Market foreclosure risk related to LTC based capacity bookings	CAM NC; CMP	Implicit auctions
				Combined Commodity-Capacity Release Scenario (a simultaneous increase up to 50% in the share of short term transmission capacities for both existing and new infrastructure and an obligation for gas producers/importers to sell at least 50% of their gas at the nearest VTP to their entry into the transmission grid on EU territory)
		Contractual congestion related to LTC based capacity bookings	Improved implementation of CMP and expiring capacity contracts can help	
Institutional constraints to market development	6. Local specifics in regulation and limited transparency	Import and export restrictions, restrictive implementation of EU legislation, licensing	Full implementation of Third Package	Storages at virtual trading point

5. STATUS QUO AND REFERENCE SCENARIO DEFINITIONS AND QUANTITATIVE WELFARE ESTIMATE FOR THESE SCENARIOS

In this chapter we present the most important assumptions, data inputs and calibration of the Reference Scenario 2020 of the EGMM[120] model, with Third Package fully implemented. We derive the model baseline in three steps. First, we calibrate the starting point "Status Quo 2016", and compare the model output to available 2016 facts on Internal Gas Market performance. In the second step we replace major model inputs (e.g., demand, domestic production, infrastructure) with forecasts for 2020, to deliver the "Status Quo 2020". Finally, we modify the model inputs to reflect the ongoing Network Code implementation process presented in Chapters 2 and 4. The derived "Reference Scenario 2020" serves as the basis for all remaining quantitative welfare calculations for alternative regulatory scenarios in this study, their results being presented in Chapter 7.

Status Quo 2016 is characterized by rather favourable gas market conditions. Low oil prices and the increasing global LNG supply dampen import gas prices and enhance competition. It also squeezes the gap between pipeline-LTC, oil-based LNG and hub prices. As a result, the price divergence among EU 28 countries is also limited. Congestion is rare on the EU transmission grid.

In the Status Quo 2020 demand fundamentals are modified according to the Primes reference demand scenario. All new infrastructure projects with Final Investment Decision (FID) according to the TYNDP 2017[121] are also included (except for Nord Stream 2).[122] A slight 1.3% demand increase is assumed from 2016 to 2020, accompanied by falling domestic production in Europe. It implies an increased share of imports from 72% in 2016 to 76% in 2020. Moreover, even though global LNG markets are still oversupplied, Asian markets are considered to recover and attract more LNG. Consequently, LNG available for European markets gets more expensive. Traditional suppliers of Europe factor this information in their pricing strategies, marketing their production at higher level.

It is assumed that Russia pursues a strategy aiming to maintain market share close to 2016 level. They trade predominantly through the existing LTCs. Only few LTCs expire by 2020, and we assume re-contracting of 30% of the original ACQ. As a result, the volume of ACQ available for the EU-28 is only 5% lower in 2020 than in 2016. Russia is also willing to offer gas on a shorter term and hub based. Pricing of spot sales are set to maximize estimated profits of the upstream supplier with the constraint that it would retain a market share of at least 30%. As the expected changes in supply and demand conditions make the European gas market tighter, profit maximizing results in higher spot prices than the formula based LTC prices in some countries.[123]

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[120] The EGMM model description can be found in Annex 6.

[121] See the List of additional transmission and storage infrastructure in Annex 7. In addition to TYNDP 2017 a new infrastructure element was included: the Baltic Connector offshore pipeline linking Estonia with Finland.

[122] Based on the request of the Commission.

[123] Spot prices are set at the Russian market with additional transport cost to the delivery point borne by the importers

	Average wholesale price EUR/MWh, (EU28)	**Price divergence % (EU28)**
2016 Status Quo	16.6	9.4%
2020 Status Quo	20.1	8.9%
2020 Reference	20.0	7.3%

Table 11: Development of modelled EU average wholesale prices and price divergence (=relative standard deviation of national wholesale prices), 2016 and 2020

The demand and supply side changes indicated above result in a 3.5 EUR/MWh average price increase in the 2020 Status Quo scenario (Figure 37). The size of the price increase is similar across Europe. Due to the elimination of some infrastructure bottlenecks, the Status Quo 2020 scenario EU 28 exhibits a stronger price convergence, even though at a higher price level. However, due to new congestions, several price differentials re-emerge between the core and peripheral countries. In most cases it results from higher demand for spot imports due to growing demand (Romania and Finland), lower domestic production (Denmark) or the assumed lower volumes of LTC renewal (Hungary). Russian spot gas is delivered to the German and Austrian market: Due to tariff pancaking hub prices get higher with the distance from the relevant hubs.

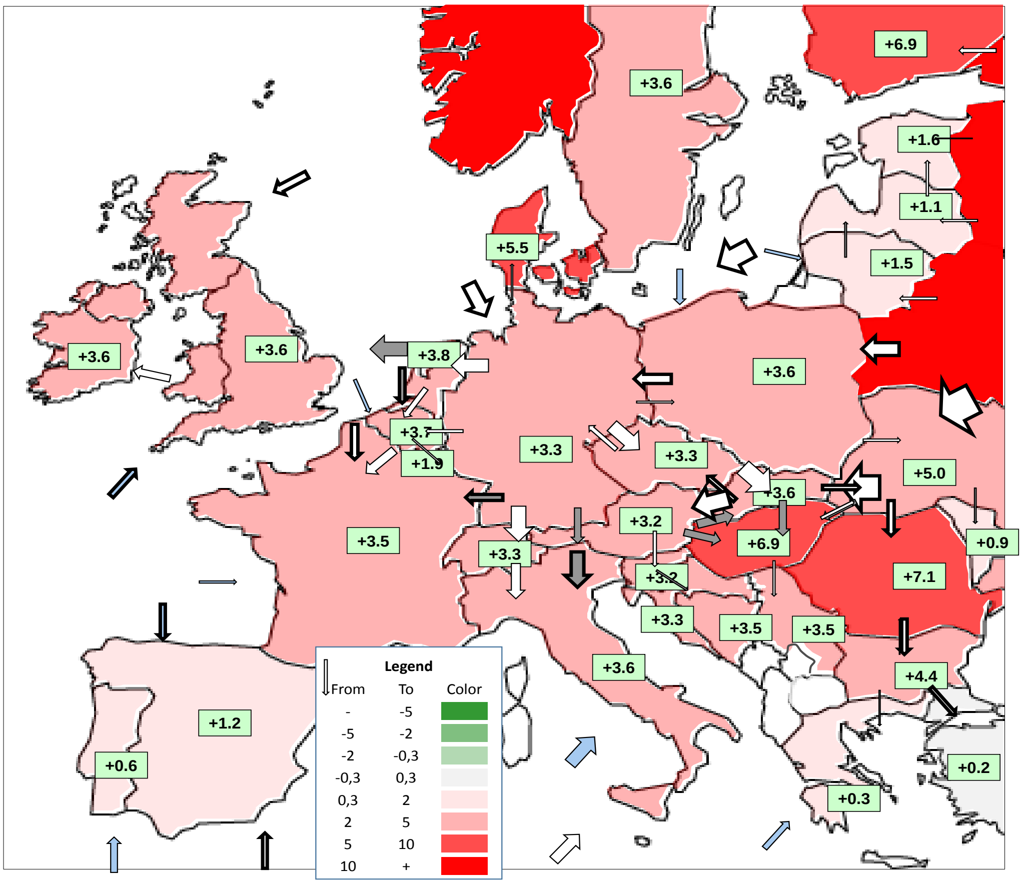

Figure 37: Modelled average yearly price change from 2016 Status Quo to 2020 Status Quo

Due to strategic pricing by the Russian supplier, LNG penetration remains constrained with imports well below the level allowed by the existing regasification capacity.

The Reference Scenario 2020 is based on the Status Quo 2020 but it also assumes full implementation of the Third Energy Package. To be able to quantify the welfare impact of the implementation of the present EU-wide regulatory framework, the implied changes had to be "translated" to modelling assumptions.

In the Reference Scenario 2020 the following assumptions represent the impact of Third Package implementation:

- The highest 15% of EU-wide entry and exit tariffs are reduced to the maximum of the remaining tariffs because of TAR NC implementation.
- Currently (2016) spot trade is restricted on certain intra-EU borders (e.g., RO-BG, BG-GR). In the 2020 Reference, no artificial regulatory barrier to trade will exist.

Third Energy Package	By 2020	EGMM
CAM NC, CMP	Implemented	Model works as CAM, CMP was implemented already in 2016 except for Trans Balkan pipeline
Incremental capacity	Implemented	No forecast available on future demand for new interconnectors
BAL NC	Implemented	Not reflected in the model – monthly model
TAR NC	Implemented	Model input will reflect implementation
Interoperability		EGMM assumes perfect interoperability (no quality, odourization, etc. technical constraints included)

Table 12: Regulatory changes of the Third Energy Package and their modelling in EGMM

As the EGMM models only monthly wholesale prices it is not able to capture the impact of BAL NC. Additionally, the model assumes perfect competition and a fully efficient utilization of transmission capacities, as if CAM NC and CMP were already implemented in the 2016 and 2020 Status Quo Scenarios. Consequently, the difference between the 2020 Reference and Status Quo scenarios underestimates the efficiency gains arising from the full implementation of the Third Package. Only the impact of TAR NC and CAM NC can be grasped numerically.

However, the Reference Scenario 2020 represents, to our best knowledge, the IGM as it looked like after a successful implementation of the Third Regulatory Package, perfectly utilizing the EU transmission grid as if implicit capacity allocation was already fully implemented by 2020. Therefore, it serves as the proper basis for quantifying the welfare impacts of alternative regulatory scenarios implementation post-Third Package (Chapter 7).

The following Figure 38 highlights the modelled prices for the 2020 Reference Scenario and price changes attributable to the above, Third Package implementation related regulatory changes. Prices decrease mostly in the peripheral countries of Eastern Europe and Ireland, characterized by high tariffs and/or trade restrictions along important interconnections.

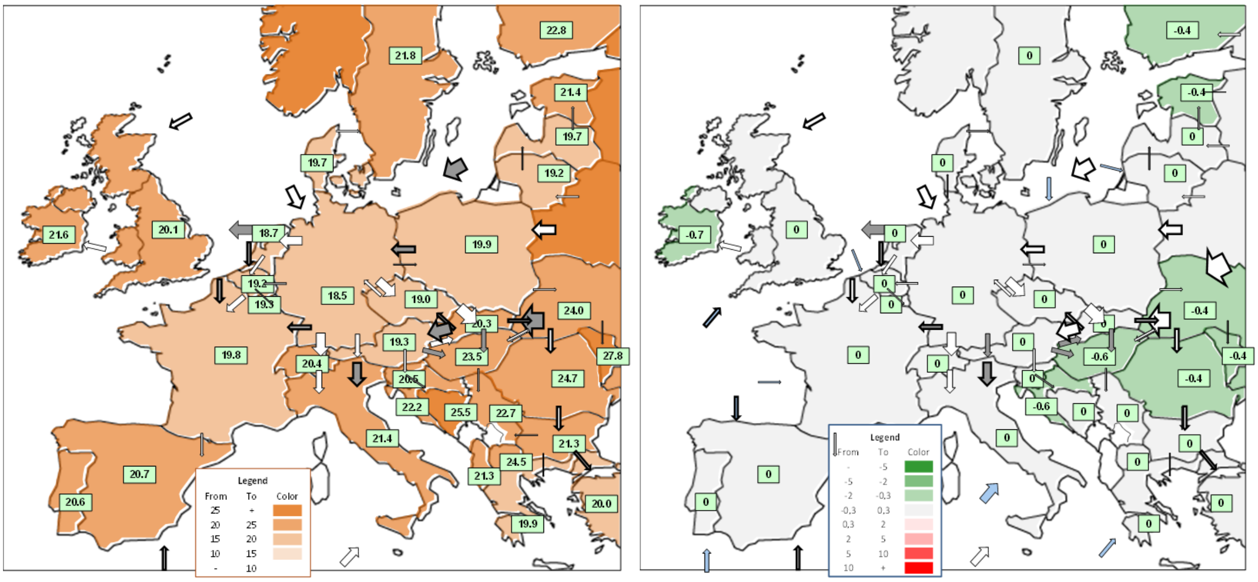

Figure 38: Modelled average yearly prices for the 2020 Reference Scenario (left) and price change from 2020 Status Quo to 2020 Reference due to Third Package implementation (right)

Source: REKK EGMM modelling

5.1 Model inputs for year 2016

Input data sources for modelling are summarized in Table 13.

Input data	Unit	Source	Comment
Yearly gas demand	TWh/year	2016: Eurostat 2020: PRIMES reference scenario	For those modelled countries not included in primes: TYNDP 2016 Green evolution
Monthly demand	In % of yearly	Eurostat	Based on fact data from 2013-15
Production	TWh/year	2016: Eurostat 2020: PRIMES reference scenario	For those modelled countries not included in primes: TYNDP 2016 Green evolution
Pipeline Capacity	GWh/day	2016: ENTSO-G capacity map, For future projects ENTSOG TYNDP 2017	
Pipeline Tariff on IP (entry+exit)	EUR/MWh	REKK calculation; regulators' and TSOs' websites: 2016: tariffs for 2016 2020: latest tariffs as of 2017 August	Uniform load factor 56.2%. new infrastructure: EUR 1.5/MWh uniform tariff UA 2020 tariffs: Naftogas data
Storage capacity[124]	Working gas: TWh, Injection and withdrawal: GWh/day	GSE	Data on each storage site – than aggregated on a country level
Storage tariff	EUR/MWh	Storage operators websites 2017 Jan	1 EUR/MWh cap is used country averages
LNG regas capacity	GWh/day	GIE	Aggregated on a country level
LNG regas tariff	GWh/day	Operators websites	Entry into pipeline network is taken into account, country averages
LNG liquefaction	GWh/day	GIIGNL 2016	Source is constrained by liquefaction capacity
LNG transport cost	EUR/MWh	REKK calculation	Distance based. Takes into account ship rates and boil off cost
Long term contracts	ACQ: TWh/year. Daily contracted quantity: GWh/day	REKK collection from press + Cedigaz	ToP flexibility except for gas islands. Delivery point on borders. Pricing based on foreign trade statistics. Delivery routes predefined based on historical flows (IEA)
Asian LNG price	EUR/MWh	Ministry of Economy, Trade and Industry of Japan 2020: Oil indexed formula	

Table 13: Input data used for EGMM model runs

Source: REKK EGMM modelling

The model was calibrated on 2016 data. For 2020 input variables PRIMES reference demand assumptions were adopted. According to the PRIMES reference case, European gas demand is projected to stabilize at the 2016 level and increase slightly over the

[124] Gas storages are represented according to the Section 1.2 of the LNG and storage follow-up study of DG Energy (2017), showing withdrawal curves, storage obligations and strategic storage.

next decade.[125] In 2016 gas consumption in the EU-28 was below 5,000 TWh and by 2020 it reaches nearly 5,300 TWh. Demand profiles vary widely across Member States, with the Baltic countries and Sweden in particular exhibiting significant demand growth compared to 2016 data. This has a small effect on the EU-28 level but is significant for country-level results. For local demand functions a uniform price flexibility of 0.1 was assumed. As indicated by the Primes reference scenario, EU domestic production is decreasing.

Regarding imports, Russia is assumed to trade on a spot and LTC basis, predominantly using LTCs for marketing its production to Europe. LTC delivery points are at the border of the importing countries[126] and allow for a flexibility of ±15%. Expiring contracts are renewed at 30% of the previous ACQ using the same pricing mechanism. By 2020 the Russian-Slovenian, Russian-Greek, Russian-Hungarian and Russian-Ukrainian contracts expire.

Norway is assumed to trade on a spot and LTC basis similar to Russia. Norway has a production cap of 1,078 TWh/year (source: TYNDP 2017). The price of this gas is set to the price of Russian spot gas.

North-African producers are considered inflexible and no option for spot trading is assumed.[127] Algerian LTC to Italy are presumed to expire by 2020. New contracts are added by TAP in the 2020 Reference: Azeri-Italian contract 80 TWh/year, Azeri-Bulgarian contract 10 TWh/year, and Azeri Greek contract 10 TWh/year.

The hypothetical maximum LNG flow into Europe according to the Follow up Study on LNG and Storage strategy estimate is 1,300 TWh in 2020, but would not be reached in the Status Quo and the Reference scenarios because the price of other sources would be cheaper.

Regarding import prices we assume exogenous LNG prices linked to oil prices. It is assumed that Europe acts as an off-taker of 'last resort', as Europe is a more competitive market than the Asian importers. The price of LNG sold to Europe is based on the opportunity cost of 'not selling' to Asia, which implies oil indexed LNG prices in Europe as well (Table 14). LNG transportation costs are calculated assuming the shortest shipment route from the liquefaction plant to the regasification facility.

From	To	Transpotation cost (EUR/MWh)	Delivery price 2016 (EUR/MWh)
US	Japan	3,8	15.0
US	UK	1.7	12.9
US	Turkey	2.3	13.5
Qatar	Japan	2.2	15.0
Qatar	UK	2.7	15.5
Qatar	Turkey	2.0	14.8

Table 14: LNG transportation costs and delivery price examples assuming EUR 15/MWh LNG price for Japan

Source: REKK EGMM modelling

[125] Note that PRIMES reported yearly gas consumption in NCV, a correction to reflect GCV was performed.

[126] Delivery point assumptions are based on PIRANI, S.–YAFIMAVA, K. [2016]: Russian Gas Transit Across Ukraine Post-2019: pipeline scenarios, gas flow consequences, and regulatory constraints, OIES Paper, 105. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2016/02/Russian-Gas-Transit-Across-Ukraine-Post-2019-NG-105.pdf

[127] We understand this might change in the future. http://www.hellenicshippingnews.com/algerias-sonatrach-eyes-jvs-with-natural-gas-traders-as-part-of-new-sales-strategy-ceo/

Russian LTC price in 2016 is based on EUROSTAT COMEXT foreign trade statistics database.[128] For 2020 scenarios prices are updated according to the estimated impact of Brent crude on long-term contracted gas prices. [129]

Spot gas in 2016 is priced at the TTF and delivered to the entry point of Nord Stream to Europe. By 2020 Russia starts spot sales in Eastern European countries as well, with delivery points in the German market for Western European consumers and on the Baumgarten hub for the Eastern and Central European consumers utilising the existing infrastructure (Nord Stream 1, Yamal and Brotherhood systems). However, Russia does not sell spot gas directly to Ukraine, non-EU countries or the Baltics.

In 2020 Russian spot prices are determined assuming profit maximization. Russian profits for different spot pricing options were estimated and compared assuming a fixed marginal cost of production. Figure 39 depicts the modelled supply structure of the EU-28 with varying Russian spot pricing strategies. It shows that up to 15 EUR/MWh no market share is lost while maximizing Russia's profits in 2020. Consequently, the Status Quo and Reference Case were calibrated to this spot price of 15 EUR/MWh. The price is set at the Russian market with additional transport cost to the delivery point borne by the importers.

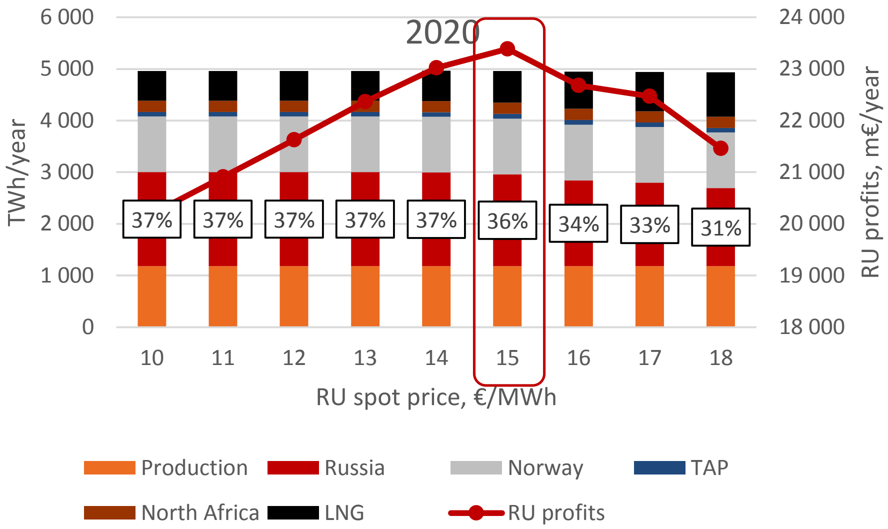

Figure 39: 2020 Supply structure in the Status Quo scenario assuming varying Russian spot price and related modelled Russian profits

Source: REKK EGMM modelling

As LNG and Russian pipeline gas compete for European market share, an alternative Russian LTC pricing assumption was also considered. The alternative formula would set Russian LTC prices marginally below LNG prices to protect Russian market share. The hypothesis would work well in countries with abundant regasification capacities. However, for inland countries further from LNG terminals pricing marginally below LNG is not a profit maximizing strategy for the LTC supplier. In addition, the original LTC pricing formula delivers the same market outcome: as both LNG and Russian LTC prices are linked to oil prices, their relative prices remain unchanged. Consequently, the

[128] EU Trade since 1988 by CN8 (DS-016890), product natural gas in gaseous state.

[129] We utilise the oil price curve of PRIMES for estimating part of LTC price development. However, PRIMES forecasts predate the oil price drop of 2014: PRIMES forecasts envisage a Brent crude oil price of 88.5 USD/barrel for 2020. PRIMES data for 2016 indicated a Brent crude oil of 86 USD/barrel, while our reference case calibration accounted for the historical price of 40 USD/barrel in 2016. For this reason, applying the absolute price of PRIMES would inflate our expectations. We opted to apply the relative price increase in the Brent crude oil price, i.e., 2% from 2016 to 2020 respectively.

Russian prices are set (although indirectly in the model) in a way to make LNG penetration contained.

Pipelines are free to be utilized up to technical capacity with no constraints except for the following interconnectors:

- For IPs connecting Europe to external markets (i.e., Russia, North Africa, Azerbaijan), suppliers are expected to market their production predominantly with LTCs, with the exception of the Nord Stream 1 and pipelines from Norway.
- Trans-Balkan pipeline is constrained by existing LTCs. Capacities got released in the Reference scenario assuming full implementation of the third package.

Pipelines from Norway have no trade constraints and Nord Stream 1 can be used up to the total capacity if long-term contracted flows allow spot trade.

Current (2016) regulatory interventions like storage obligations do not change in the 2020 Reference.

5.2 Projected market outcomes

In this Section we summarize major market development trends between 2016 and 2020, emerging from the 2020 Reference Scenario creation process. Changes in supply structure, wholesale prices, IP utilization and congestion, transit flows and TSO revenues are presented.

5.2.1 Supply structure development

To see whether EGMM can accurately reproduce the actual 2016 supply structure of the modelled region, a validation was carried out using 2016 data as published by Eurostat[130] and IEA.[131] Flows along main pipelines and LNG terminals into Europe were aggregated at the EU28 and on EU28+Turkey levels and compared to EGMM outputs. We also highlight the most important developments in main model outputs caused by the modified input sets in the Status Quo 2020 and Reference 2020 scenarios.

The results depicted in Figure 40 indicate that the modelled 2016 supply structure is almost identical to what can be derived from actual published data and reproduces the actual market share of major gas supply sources. By 2020, declining domestic production give rise to Russian and LNG deliveries so that the EU's import dependence increases by 4%. Regarding the supply structure of the EU-28, the 2020 Status Quo and the Reference case are nearly identical.

[130] Supply, transformation and consumption of gas - annual data

[131] https://www.iea.org/gtf/

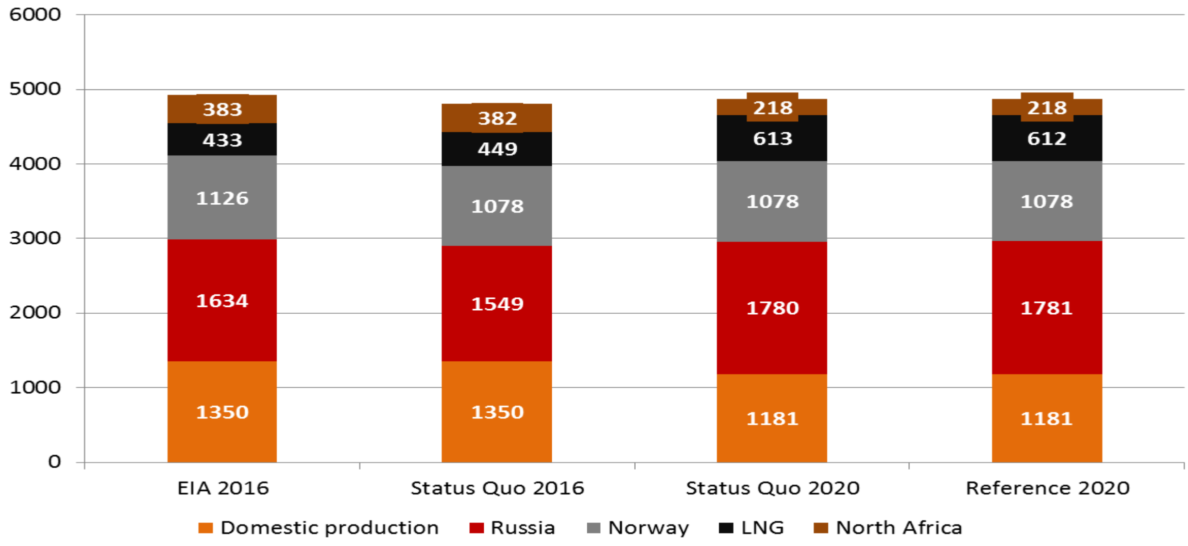

Figure 40: Supply structure in different scenarios (TWh)

Source: REKK EGMM modelling

5.2.2 *Wholesale price development*

Along with supply structure, modelled equilibrium prices were tested against actual 2016 wholesale gas prices in Europe for countries with available transparent wholesale gas price information.[132] For this purpose, a volume-weighted average European wholesale price (i.e., larger markets have more effect on this figure) was calculated from wholesale price information published in the EU Quarterly Reports and compared to the result of the same calculation from 2016 EGMM outputs (see Figure 41 below). The resulting wholesale prices were 16.27 EUR/MWh and 16.52 EUR/MWh, respectively, a difference of less than 2%. Modelled prices are 0.54 EUR/MWh above published prices according to the average absolute difference. The results confirm the accuracy of the model in this regard.

By 2020 the model indicates an increase in the average wholesale European price level reaching 20.1EUR/MWh in the Status Quo scenario. Modelled 2020 Reference prices are almost identical to the Status Quo scenario, except for countries where outlier tariffs were cut back: Bosnia and Herzegovina, Bulgaria, Estonia, Spain, Croatia, Ireland, Macedonia, Serbia, Sweden. Country-specific wholesale price development between 2016 and the 2020 Reference is depicted in Figure 41.

[132] Wholesale price comparison covered the following countries: AT, BE, BG, CZ, DE, DK, EE, ES, FI, FR, GR, HU, IT, LT, LV, NL, PL, RO, SE, SI, SK and UK.

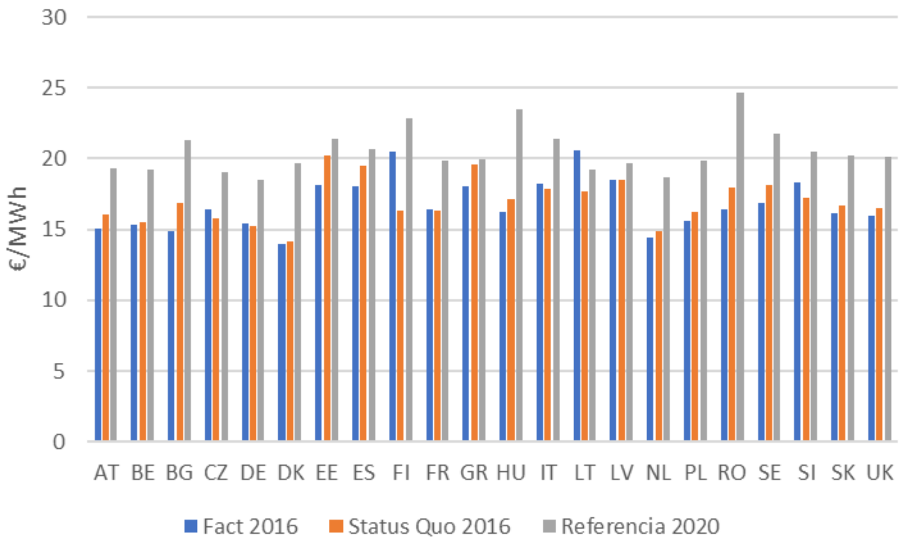

Figure 41: Wholesale price development from 2016 to 2020 Reference for countries with available EU Quarterly Report data

Source: EU Quarterly Reports and REKK EGMM modelling

5.2.3 IP utilization levels and congestion

The 2016 modelled results show little congestion across the European network. Norwegian pipelines supplying France and Belgium, Nord Stream 1, the France-Spain and the Austria-Hungary interconnections show permanent congestion.

However, in the 2020 Reference more congested pipelines emerge. The primary reason for that is higher import need to meet growing demand and replacing decreasing domestic production. In addition, growing reliance on spot gas instead of LTCs redirects import flows.[133] As a result, congestion occurs along the traditional supply routes for Norway (to France and Belgium) and Russia (Nord Stream 1, Yamal and the Ukraine-Slovakia Brotherhood IP) and transit routes to deliver Russian gas to Austria, Italy, Germany and France. The supply routes to serve the region South to the Brotherhood pipeline become seriously congested (Table 15).

[133] Russian LTC gas is delivered to the border of contracting countries while spot gas is distributed from to the German and Austrian hubs.

2016 Status Quo		2020 Reference	
NO-FR	100%	RU-DE	100%
RU-DE	100%	RU-PL	100%
NO-BE	99%	SK-AT	100%
FR-ES	97%	BG-RO	100%
AT-HU	89%	PL-UA	100%
		SK-HU	100%
		SK-UA	100%
		AT-HU	100%
		NO-FR	100%
		NO-BE	100%
		AT-IT	98%
		DE-FR	98%
		UA-SK	96%
		PL-DE	91%

Table 15: IPs with higher than 85% utilization in 2016 and 2020

Source: REKK EGMM modelling

5.2.4 Transit flows for modelled countries

For 2016 EGMM simulates considerably lower transit flows[134] than the actual transit observed: IEA gas trade flows database suggests ~4100 TWh of annual transits, while modelling can only deliver 3000 TWh a year. Again, the discrepancy can be attributed to more 'efficient' trades on the existing infrastructure in the model compared to the 2016 reality. By 2020 transit flows intensify as import dependency increases in Europe.

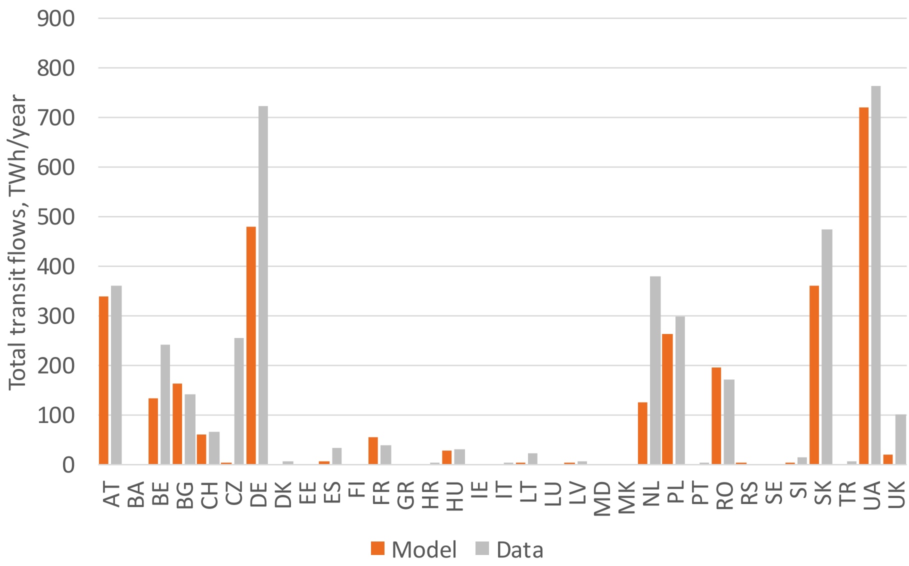

Figure 42: Modelled and actual transit flows by country, 2016, TWh/year

Source: REKK EGMM modelling and REKK based on IEA

[134] Country-level transit flows are considered to be the minimum of imports and exports since producer countries may export more than they import (e.g. Netherlands).

5.2.5 TSO revenues

TSO revenues are difficult to determine. For 2016 available data shows an annual income for EU-28 TSOs of EUR 10-15 bn[135], while REKK modelling computes EUR 9.2 bn TSO income, close to the lower edge of the range.[136] The reason for a wide discrepancy may be due to the fact that modelling allows for more efficient transport route utilization leading to lower flows and lower tariff revenues. Moreover, EGMM uses a single tariff for each IP, which would potentially underestimate revenues from shorter term products.

In the Status Quo 2020 scenario, TSO revenues increase considerably compared to the 2016 levels. This may also be attributed to higher import requirements and network utilisation in Europe due to lower domestic production. Auction revenues are also higher, indicating that more pipelines get congested. In the reference 2020 scenario decreased tariffs lead to some TSO revenue losses, but overall TSO revenues are not significantly affected by the relevant regulatory changes.

	Status Quo 2016 with 2016 tariffs	Status Quo 2016 with 2017 tariffs	Status Quo 2020	Reference 2020
TSO IP income	5,055	5,430	5,797	5,482
TSO storage income	122	122	145	145
TSO domestic exit income	2,710	2,709	2,847	2,849
TSO production income	683	683	542	542
TSO LNG entry income	163	323	224	223
TSO auction revenue	455	485	644	558
Total TSO income	**9,187**	**9,752**	**10,199**	**9,800**

Table 16: TSO revenues: Comparison of Status Quo and Reference cases, EURm

Source: REKK EGMM modelling

[135] Some TSOs publish only the group-related revenues (e.g., in Spain Enagas reports the total revenue of Enagas group, including South-American TSOs and LNG terminals), others do not differentiate between transmission-related activity and other activities (when the TSO is active in LNG terminal operation as well).

[136] TSO income incorporates all tariff-related revenues on IPs, storage facilities, production, LNG entry points, and exit to domestic distribution system.

6. DEFINITION AND DETAILED QUALITATIVE ASSESSMENT OF ALTERNATIVE REGULATORY SCENARIOS

6.1 Tariff Reform Scenario

Cross-border (within a country: intra-system) entry/exit tariffs, especially multipliers for short term products, have been identified as trade barriers for the EU internal gas market. These tariffs create pancaking, may contribute to congestion problems, reduce the contestability of local markets or impede cross-border flexibility transactions. Regional market area mergers or the implementation of the TAR NC are not likely to resolve the related market inefficiencies in the years to come. This scenario is put forward to eliminate the above inefficiencies.

By reforming the tariff setting principles of the Reference Scenario as described by this alternative regulatory scenario, we expect a positive impact due to improved efficiency in using the existing EU gas transmission infrastructure and improved liquidity on local markets and better ability to cope with different external impact scenarios. The implementation of the Tariff Reform Scenario could help expanding the likely positive price impact of the emerging LNG-pipeline gas competition to the entire EU territory. The elimination of intra-EU cross-border tariffs could also reduce the costs of imported or exported flexibility from other zones/countries.

6.1.1 Introduction and motives for considering this scenario

In the Reference Scenario, we see a well-interconnected IGM in most parts of Europe. Nevertheless, as discussed earlier, the current situation of overbooked transmission capacity by LTCs will change between 2020 and 2030. Unless any regulatory or significant tariff change comes, this may lead to a more profound price segmentation of the IGM with greater location spreads compared to today, which will fully reflect transmission tariffs and physical flow direction. This may happen because new capacity bookings after expired LTCs will come at actual booking cost to traders as the opportunity price.

Hence, by reforming the tariff setting principles of the Reference Scenario as described below, we expect to evidence an improved use of the existing EU gas transmission infrastructure. We propose setting cross-border tariffs to zero to eliminate the main cause of location spread between zones in the case of available transmission capacity. The reduction of intra-EU cross-border tariffs to zero should also reduce the costs of imported or exported flexibility from other zones/countries. Consequently, to keep also the flexibility from underground storages competitive, the underground storage transmission tariff will be reduced to zero.

In this scenario, TSOs would be facing decreasing revenues due to cross-border tariff reduction. Assuming TSO revenue neutrality, the deficit would be compensated by collections from the EU entry tariffs or higher domestic tariffs, which could reflect the transmission costs from upstream EU countries. For zones without extra-EU entry point, these revenues would need to be reallocated to or from upstream TSOs via some compensation scheme.

The introduction of a TSO Compensation Fund (TCF) is the proposed compensation scheme. Its establishment would represent a complex task. However, it can also help regulatory convergence in the EU as a consistent regulatory approach across EU countries is required for a well-functioning TCF. Because this scenario does not support long-term bookings, another form of financing the new transit infrastructure will have to be developed. Some sort of TCF agreement will be needed on new transit or upgrade of current infrastructure because after commissioning of the investments they should be included into TCF. For that reason, the TCF should have a say which infrastructure is increasing the EU welfare and thus will be covered through TCF. TCF should look at new transit or upgrade of current infrastructure projects from the EU perspective, not only for the concerned TSOs, but also all EU TSOs, some of which might be impacted indirectly in their alternative infrastructures.

TCF functioning is discussed in more detail in the box at the end of the Section 6.1.3.2.

6.1.2 How this scenario addresses market inefficiencies

1.	Transmission tariff levels and structure	Zero cross border tariffs (reserve price) will eliminate tariff pancaking and shall reduce location spreads and allow free gas flow and flexibility exchange between zones/countries on IPs with no physical restrictions. Unit fee or harmonised tariff to be applied on EU border entry and exit tariffs to compensate revenues for the eliminated intra-EU tariffs.
2.	Regulatory and contractual restrictions	LTCs will not have the same function as currently (long-term infrastructure remuneration). Some points may be contractually and physically congested but different routes or interruptible products with low probability of interruption can be used. Also changes in CAM NC to promote short-term capacity products instead of long-term products or in CMP for greater use of over-subscription and buy-back mechanism is possible.
3.	Physical restrictions	This scenario helps to identify physically congested pipelines or areas from the whole-EU perspective. If one pipeline is fully booked there may be another physical route for shippers to deliver gas to the desired destination market for zero or low tariffs.
4.	Infrastructure use efficiency	Improved efficiency in using the existing EU gas transmission network as location spreads decrease and contractual capacity use restrictions are reduced. Zero cross border tariffs will decrease the price of sourcing flexibility via reduced location spreads and cheaper flow substitution. If common central dispatching is introduced, it will help to route the gas flows in the most efficient and economical way, especially in case when inter-zones IPs are virtualised. It will also help to identify infrastructure deficits from EU-wide perspective.
5.	EU-level market concentration	Zero intra-EU tariffs will increase producer to producer supply competition on the European market. Reduction of costs to use alternative opportunity routes shall also increase the competition in local markets.
6.	Local specifics in regulation and limited transparency	Because the introduction of TCF is perceived in this scenario, an increased level of economic regulation harmonisation will be needed.

Table 17: Tariff Reform Scenario addressing market inefficiencies

6.1.3 Main amendments to the Reference Scenario

6.1.3.1 Entry-exit zones

As per Reference Scenario.

This scenario should lead to a single market functioning even without the necessary market mergers. Nevertheless, it is able to accommodate any regional market mergers or conditional market merger arrangements. It is compatible with any of the following alternative scenarios.

6.1.3.2 Tariffs

The tariff change is the most important feature of this alternative scenario. The tariffs from the Reference Scenario and their structure would change to:

- Intra-EU cross-border tariffs set to 0 (reserve price). Cross-border capacities would be allocated by auctions so that in the event of oversubscription congestion revenues would reflect scarcity (for detailed description and arguments please refer further in this section).

- Gas storage entry/exit tariff set to 0. Unit fee to be applied on EU border entry and exit tariffs, or alternatively EU entry/exit tariffs will be harmonised and likely increased to compensate revenues for the eliminated intra-EU tariffs[137].

- Domestic exit tariffs will be taken as before, alternatively they can be increased to reflect part of the upstream infrastructure costs.

This scenario is designed in line with our general approach, in a revenue neutral manner for each TSO in relation to cross-border (transit) flows. The revenue loss or gain from the cross-border transmission flows will be compensated via an EU-wide TCF and added to entry tariffs. TCF will be financed from EU entry/exit tariffs, and possibly also from a surcharge applied on domestic exit tariff.

The change within this scenario does not apply to DSO tariffs, which are not relevant for this study, nor any other charges that are not directly related to the use of the transmission system by traders/shippers.

Because it is assumed that the TSO's total allowed revenues should remain the same, it is necessary to collect the remaining part of the TSO's allowed revenues through the remaining points of the grid – EU entry/exit tariffs and domestic exit tariffs. For EU border entry and exit points, we propose establishing one additional unit fee to be applied on EU border entry and exit tariffs in addition to the current tariffs or alternatively to calculate the unit EU entry tariff based on expected volumes at unified level for all EU pipeline and LNG terminal entries.

We expect that the changes proposed in this Tariff Reform Scenario will have the following impacts:

- Zero intra-EU tariffs will increase producer to producer supply competition on the European market and further decrease the price of sourcing flexibility

[137] For the case of this scenario, we expect Switzerland to be compliant with EU rules so as not to be bypassed by gas market participants. Therefore, EU entry/exit fees will not be charged on the Swiss border and Switzerland will be considered to operate in the same way as an EU member state in this regulatory scenario.

(marginally from local storages and more importantly from other EU zones) via reduced location spreads and cheaper substitution.

- The idea of keeping the domestic exit tariffs without major change and instead financing the TSOs' transit related costs from the EU entry tariffs is based on the following economic considerations:

    - The further away in the value chain the tariff is applied from the end consumer, the less probable it is that its full value will be paid by the end customer because of competitive pricing pressures and of the possibility that part of it will be borne by other market participants.

    - The higher the EU entry tariffs, the higher financial guarantees will be needed (by the producer/supplier with the TSO or market operator). They are easier to bear by up-streamers (large companies with good ratings) than if collected at domestic exit points from end customer suppliers in the case of high domestic exit, which would have to provide some additional guarantees with impact on the supplier's pricing (potential price increase would lead to customer welfare loss).

- With the proposed EU entry tariff increase it could happen that the gas price in some EU regions, which directly receive large deliveries from non-EU countries, could actually increase as a result of increased EU entry tariffs and eliminated intra-EU tariffs. The reason is that such a country's EU entry tariffs would implicitly include a share of the eliminated intra-EU tariffs and prices within the EU would converge. The overall EU market price impact should, however, be positive due to eliminated location spreads and increased market liquidity and producer to producer competition.

- The higher the EU entry/exit tariffs, the lower the expected cross-EU-border flexibility use. This implies higher utilisation of gas storage within the EU as flexibility source. But it is important to highlight that most of the flexibility is sourced from gas storage within the EU and the access to this flexibility will be less costly and hence easily used.

EU entry/exit tariff adjustment discussion

As discussed above, setting the intra-EU entry/exit tariffs to zero will have to be compensated for. In order to achieve the TSO revenue neutrality, the domestic exit tariff and also the EU border entry/exit tariff will be increased. Such an increase could be executed by either (i) an add-on tariff, i.e., a unified surcharge to the existing EU-border tariffs or by (ii) harmonized EU entry/exit tariff. Both options have their advantages and disadvantages, which we compare below.

Add-on tariffs

The add-on approach preserves the current differences between individual EU-border entry/exit tariffs. It builds on the historical assessment of the individual importing EU-border countries.

This approach is easy to implement, which is its main advantage. On the other hand, it poses several significant disadvantages. As the base tariff (which will be still country specific) can be adjusted individually by EU-border countries, this might lead to magnification of differences between individual entry tariffs (e.g., to influence the producer portfolio or to optimize tariff for domestic TSOs), which could be opposed by the exporters as discrimination and potential violation of the WTO rules. Moreover, the base tariff might be opportunistically adjusted on a country/market zone basis before the add-on approach is applied, hence changing the inception conditions. It is also worth noting, that this approach creates an opportunity to EU Member States competition for one producer in the case of the existence of multiple supply routes (e.g., several countries might be competing by lowering the entry tariff to attract the Russian imports to be shipped via their infrastructure) and increasing the dependence on the TCF compensation from other TSOs.

Harmonised tariffs

This approach is based on setting unified entry/exit tariffs on all EU-border IPs.

Its main advantage is that this approach is more transparent and provides more tariff predictability for the market participants as the tariffs would be set on the EU level. It would be a clean solution from the WTO rule perspective as all suppliers would face the same regulatory principles and tariffs when entering the EU, and it would not allow for preference of certain supply routes based on their length, origin or other parameters. Naturally it is assumed that, similarly to the previous option, the total tariff impact would be neutral, the same target revenues for the same services would be collected on the side of the TSOs as in the Reference Scenario. On the other hand, this approach could lead to individual higher producer and end-customer impact dispersion as the difference to the entry/exit tariffs currently in force might be higher compared to the add-on approach. Furthermore, we expect slight wholesale price increases in countries at EU-borders and respective decreases in the internal destination countries. But this could be addressed and compensated by TCF and domestic exit tariffs.

Potential special sensitivities to look at in this scenario:

- Supplier specific EU entry tariffs - possible differentiation of pipeline-based and LNG-based EU import tariffs as a potential way of increasing supplier competition.

- EU entry tariff to be complemented by domestic exit tariff adjustment to avoid full socialisation of TSOs’ transit related costs and the related distorted cost efficiency and investment incentives.

The introduction of the TCF mechanism is crucial for the proper functioning of this scenario. For this purpose, we assume that the economic regulation of TSOs is harmonized at the EU level (see below) and domestic exit tariffs are set in each country along similar principles. The objective of the TCF is to compensate TSOs for (part of) their transit related justified costs from revenues collected at EU entry/exit points. Today, this service is paid by the shipper in the form of entry and exit cross-border tariffs and thus is part of the commodity price paid by the customer. In this scenario the commodity price will no longer reflect the costs of upstream TSOs and will need to be collected at an EU border point or domestic exit point in the form of an extra fee.

The TSO Compensation Fund – Key Principles

The key measure of this scenario is setting the within-EU IP entry/exit tariffs to zero and a simultaneous establishment of a TSO Compensation Fund (TCF).

Non-contracted IP capacities continue to be allocated through auctioning (according to the CAM NC) but priced only for congestion. Capacities already booked by LT capacity contracts might remain priced according to the LTC. If the capacity holder does not wish to maintain its long-term contract, it would be given the opportunity to withdraw from it and enter an auction. The table below summarises major IP access conditions under the Tariff Reform Scenario.

	Already booked capacity	**Remaining capacity**
Capacity allocation	LT capacity booking or auction	Auction
Pricing of allocated capacity	According to LTC or auction price only (zero if there is no congestion)	Auction price only (zero if there is no congestion)

Table 18: IP access conditions under the Tariff Reform Scenario.

The TSO Compensation Fund

The implementation of the primary measure of this scenario (i.e., setting within-EU IP entry/exit tariffs to zero) would result in the loss of within-EU IP related tariff-based revenues of TSOs compared to the status quo. In 2016 IP related TSO revenues were at around EUR 4 bn.[138] Note that the scenario would not lead to the loss of TSO revenues from congestion, LT bookings and IP-related non-regulated activities (if any).

The table below summarises our proposed major design principles for the TCF.

Time horizon	**Major TCF design principles**	**Brief description**
Initial phase	Objective	Ensure the revenue neutrality of the Tariff Reform Scenario by compensating TSOs for lost justified revenues collected at intra-EU IPs before intra-EU entry/exit tariffs are set to zero.
	TCF revenue target	Sum of TSOs IP related revenues **minus** congestion revenues **minus** revenue from LT booked IP capacity **minus** IP related revenues from non-regulated activities (if any)
	Unit add-on fee or uniform tariff (to be applied on EU border entry and exit tariffs) calculation	ACER, based on the TSOs proposals approved by NRAs

Going concern	Objective	To fund (part or full of) TSO's intra-EU gas transit related justified costs, based on actual transited flows, from the TCF instead of cross-border entry/exit tariffs
	Precondition	Assessment of TSO's intra-EU gas transit related justified costs with a harmonized methodology, as part of the TAR NC implementation process
	Transit definition	Minimum of gas inflow and outflow related to a market zone in each period
	TCF revenue target	Sum of TSO's intra-EU gas transit related justified costs
	Source	Unit fee (EUR/MWh) added to EU border entry and exit tariffs (Sum of justified costs / Sum of gas flows through EU border entry and exit points in each period), possible secondary redistribution could stem from domestic exit points
	Unit add-on fee or uniform tariff calculation	ACER, based on the TSOs proposals approved by NRAs
	Payments to the TCF	Made by gas importers to and exporters from the EU to a single TCF account managed by an institution appointed by the Directive (e.g., ACER) Additional tariff on domestic exit points, if implemented.
	Payment periods and ex-post corrections	To be defined later

Table 19: Major TCF design components

Objective of TCF

We assume that IP-related TSO tariffs are necessary to collect the justified TSO revenues, established by NRAs in the Status Quo. Therefore, a compensation scheme to provide for revenue neutrality in the early implementation phase of this scenario must be established parallel to the primary measure coming into effect. The TCF serves exactly this objective. In the longer term, the objective of the Fund is the EU-wide socialisation of (part or full) TSO's intra-EU gas transit related justified costs and overall transit flows.

TCF revenue target

In the early phase of the tariff reform implementation the revenue target for the TCF is defined as the lost within-EU IP related tariff-based revenues of TSOs. However, we propose to adjust this revenue target later so that it becomes proportional to the justified cost of TSOs to provide gas transit for more downstream systems. There are at least two important reasons for this adjustment.

[138] Data provided in the presentation by Torben Brabo (GIE) at the Madrid Forum, 19-20 October 2017.

- We expect that within-EU IP tariff removal will significantly impact future gas flows and related utilisation of gas transmission assets EU-wide. This will necessitate a re-assessment of TSO justified costs and the related tariff systems to remunerate them. With changing utilisation patterns revenue grandfathering will provide increasingly distorted cost efficiency and investment signals for TSOs.
- The implementation of TAR NC will soon provide detailed and transparently available information on TSO justified costs, their categories and tariff setting principles by NRAs. We expect this information will be sufficient to quantify transit-related justified costs of TSOs and on this basis, adjust the TCF revenue target from early grandfathering of lost revenues to recover transit related costs.

EGMM modelling supports the hypothesis that currently regulated IP tariffs are set by NRAs so that the more gas a market zone / TSO is transiting, the more IP revenue the affected TSOs are allowed to earn by the regulator (see Figure 43 below). Setting IP related entry/exit fees to zero would deprive TSOs mostly from transit related revenues, covering transit related justified costs. This finding provides the basis for defining the objective of the TCF in a narrow, focused way so that it funds (part or full) TSO's intra-EU gas transit related justified costs, based on actual transited flows.

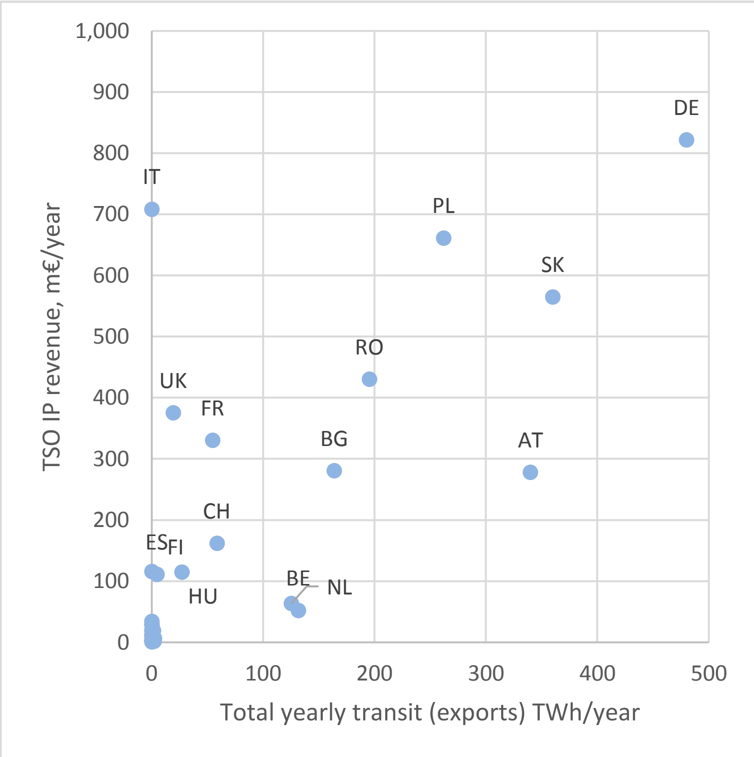

Figure 43: The relationship between annual gas transit and IP related TSO revenues (EGMM modelled, 2016)

Note: Transit is defined as the minimum of annual gross import and export flows forecasted by EGMM. Non-labelled data points at the origin of the graph include BA, CZ, DK, EE, FI, GR, HR, IE, IT, LT, LU, LV, MD, MK, PT, RS, SE, SI, TR

Source: EGMM modelling result from 2016 Status Quo Scenario

Revenue collection and redistribution mechanism

According to our proposed TCF design, the revenue of the TCF to compensate for the lowered reserve price at the intra-EU IPs is to be collected from two sources, (i) from the entry/exit tariffs at the EU border and (ii) at the domestic exit point, or from their combination. The exact proportion of the two revenue sources would need to be determined later based on the modelling and assessment of their impacts.

The TCF source at the EU border would be, as discussed earlier in the report, either a unit add-on fee (EUR/MWh), or an EU-wide harmonised tariff, or additional tariff on domestic exit points, if implemented. The add-on tariff is added to EU border entry and exit tariffs in a non-discriminatory manner (pipeline and LNG paying the same). In this way, each MWh of gas entering the EU market would contribute with the same amount to the Fund. The gas importers to and exporters from the EU would be obliged to pay their TCF contribution at the EU border to a single TCF account, managed by an institution appointed by the Gas Directive (e.g., ACER).

A simple fundamental for unit fee calculation for each period (e.g., year) could be:

- In the early phase: (IP related revenues – congestion revenues – revenue from LT booked IP capacity – IP related revenues from non-regulated activities)/ Sum of gas flows through EU border entry and exit points
- After adjusting the revenue target: (Sum of transit related justified costs / Sum of gas flows through EU border entry and exit points in each period)

A key difference of this TCF design compared to the existing electricity and the gas Inter-TSO Compensation (ITC) schemes is that its revenue would come from payments by suppliers/traders. TSOs would not have to pay into the Fund but could only receive from it, according to pre-defined, transparent and non-discriminatory rules. TCF can be designed so that it operates without inter-TSO transactions and related inter-TSO arrangements. Individual TSOs having transaction only with the Fund manager in this case.

Nevertheless, if some domestic exit tariff adjustment was introduced, there would arise the need to make also payments from TSO to the Fund. Still, no inter-TSO transactions are foreseen, because transactions only with the Fund manager are expected.

Alternatively the TCF source at the border could be one harmonised unit tariff for all the EU entry and exit points, which would be transparently and non-discriminatorily applied at the EU border. In this case a collection through TSOs would make more sense. A potential concern with the above basic revenue collection and redistribution design is that a 100% recovery of historic or justified transit related costs for TSOs might contain distorted cost efficiency and investment incentives. The full EU-wide transit cost socialisation could reduce the incentive of TSOs to efficiently manage their transit related costs in the case of lower transparency. It could also encourage inefficient investment into transmission assets serving gas transit if investment decision welfare evaluation on the full network and clear cost review and benchmarking were not part of the TCF functioning.

Common central dispatching introduced on EU level, where all inter-zone IPs are virtualised, could partly address this issue because its motivation should be to dispatch gas flows within the EU in the most efficient and economical way. If there were two or more possible gas routes from A to B, the central dispatching body should use the one which is less costly and after full utilisation of the cheaper route, another route could be used. Central dispatching body however is not necessary precondition for proper functioning of this scenario nor TCF.

One potential solution to address the problem of distorted incentives of the basic design, which must be addressed under the TAR NC, is partial socialisation. Such a scheme would ensure NRAs keep full control over the related costs and investments since they will have to consider those costs and approve investments when setting domestic exit tariffs.

When assessing the impact of the Tariff Reform Scenario on overall EU welfare by the EGMM, we will investigate both versions (100% EU border – 0% domestic exit versus 50%-50%).

Of course, if this scenario was further developed another proportion can be agreed, e.g., to reflect the importance of transit flows for the given TSO.

There are other principles, on which TCF stands, such as that:

- It should ensure that such a mechanism would not lead to higher grid fees and if TCF was introduced, harmonisation of the methodology to calculate justified revenues (grid fees) would be needed (this is also mentioned in Section 6.1.3.3)
- An independent auditor would be needed to oversee the TCF and the fee structure.

Illustrative market design impact of the Tariff Reform Scenario in comparison to the current situation

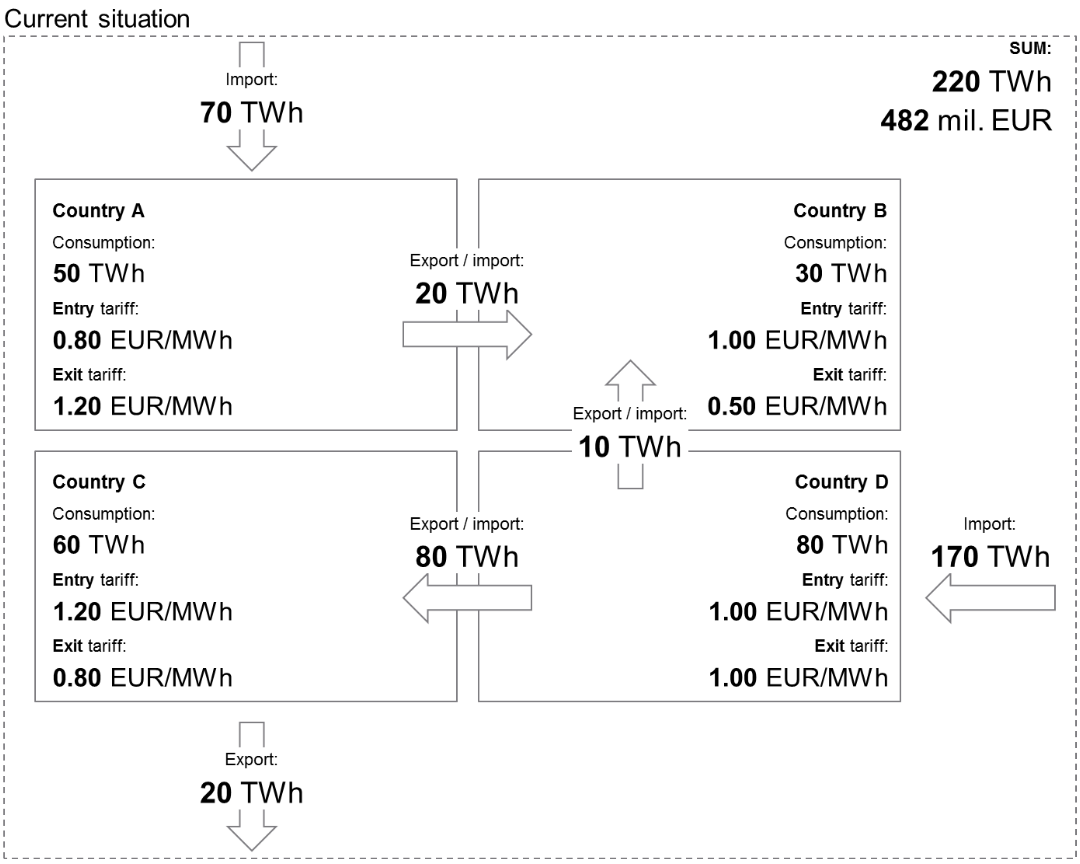

Figure 44: Current situation

Source: EY

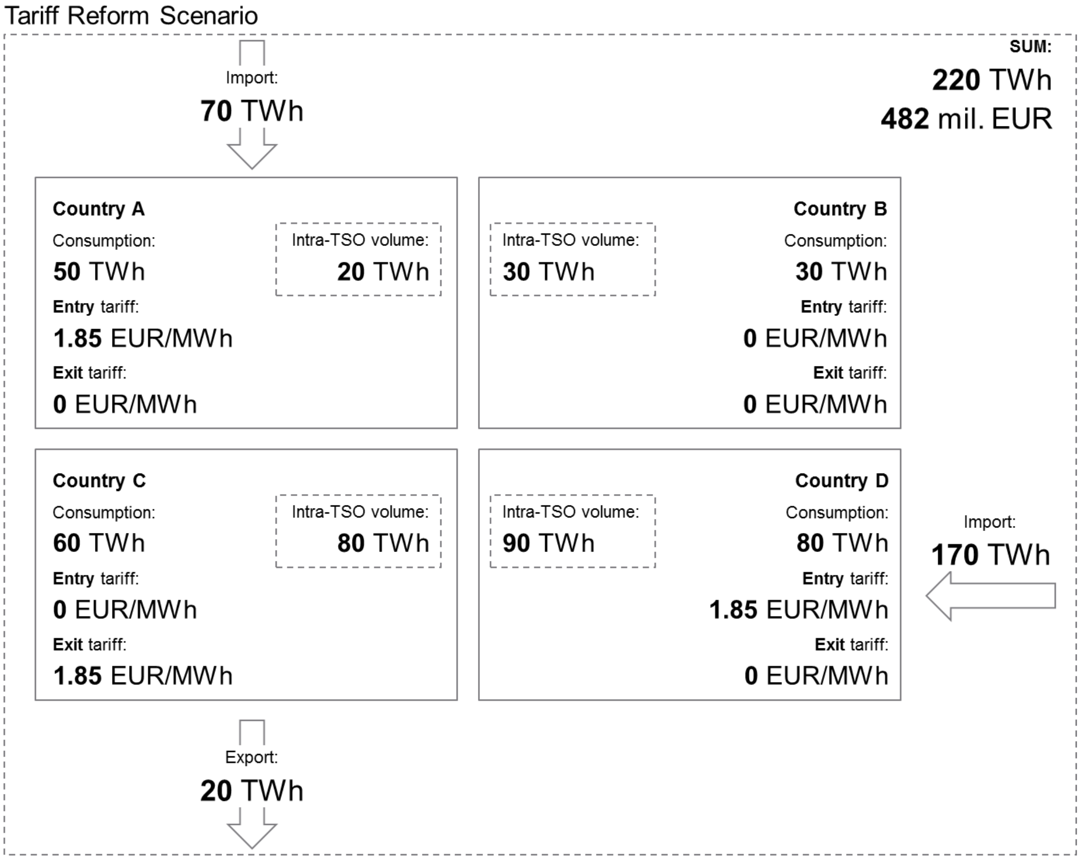

Figure 45: Tariff Reform Scenario

Source: EY

6.1.3.3 Economic Regulation

As discussed above, an EU-wide TCF mechanism needs to be introduced, and it is needed to harmonise the regulatory approach to setting allowed revenues (harmonisation of approach to RAB, factor of efficiency, OPEX size, WACC, necessary infrastructure remuneration), because part of the revenues in some countries will be covered through the TCF and it is necessary to ensure that only eligible cost, reasonable profit or efficient size of the infrastructure (with regard to SoS requirements) is covered.

If the approach to the allowed revenue calculation were not harmonised, TSOs and also NRAs could be motivated to either outright increase allowed revenues or only increase the part of the allowed revenues covered by the TCF – given the EU entry/exit tariffs, intra-EU tariffs set to zero and trying to minimise the share to be paid as a domestic exit tariff.

6.1.3.4 Capacity LTCs

We assume that due to tariff reduction to zero at intra-EU cross-border points, capacity LTCs can continue to exist but will not have the same function as it does currently, meaning that they will not fix the future transmission costs and thus remunerate part of the infrastructure cost. The potential challenge in this scenario could be possible capacity hoarding because capacity LTCs will be cheap to contract.

Even today, and the more so for the Reference Scenario, we do not see many fully utilised pipelines with physical congestion, which means that IPs may be contractually congested, but not fully used. Under CMP application on contractually congested interconnection points there should be available released physical capacity at least on a day-ahead basis. Further, the risk of capacity hoarding can be mitigated by the following:

- CAM NC update towards short-term capacity preference. Allow booking only in accordance with end customer needs, e.g., maximum five years in very small total amount (e.g., 10%) and then small proportions in two and three year tenors (e.g., cumulative 20% for two years and cumulative 30% for three years), with the most volume left to short-term bookings (e.g., 70% for yearly capacity and shorter). The current full implementation of CAM is assumed in the Reference Scenario.

- Within the applied regulatory regimes the NRAs should clearly motivate TSOs to a more proactive use of overbooking and buy-back procedures and to cancel any longer term booked (one year and longer) unused capacity in the case of contractual capacity congestion. This market-based approach applicable for the short-term capacity management would be clearly preferred by the market players to the use-it-or-lose-it principle. The current full implementation of CMP is assumed in the Reference Scenario.

- Low initial capacity prices should contribute against capacity hoarding intentions as competitors, in the case of fully-booked direct routes, could at the initial zero tariffs book and use circumventing routes to the desired destination. . This should generally work as preventive discouragement for any capacity hoarding intent or ex post deem the capacity auction premium as a sunk cost not transferrable into the market prices.

- Booked and unused capacity accumulation on multiple cross-border points should be actively observed within transparency and market manipulation prevention platforms (i.e., REMIT, competition law) and followed through, if suspected of market manipulation.

A question can be raised about what happens to the existing capacity LTCs (in the Reference Scenario we still assume their existence). We have to clearly distinguish between variable price and fixed price capacity LTCs. For both cases, certain measures can be taken before full implementation of the Tariff Reform Scenario to eliminate the coexistence of outstanding, non-complinant LTCs with new market conditions on intra-EU IPs. In the transitional period, CAM NC could be amended by provision on maximum duration of new long term contracts. Such a provision can state that new LTCs must terminate before certain date in the future, when new market model comes into force.

For fixed price LTCs basically no adjustment is needed as the capacity booking procedure will continue to exist, but their prices would be different from the newly-available tariffs. In the case of variable prices, prices would be automatically adjusted to the current reserve prices, which means that after implementation of Tariff Reform Scenario, the tariff for capacity LTCs with variable price will be zero reserve price plus auction premium. This way capacity holders would be favoured to those who did not book capacity before the scenario implementation. This situation should be avoided to any extent possible, e.g., by transitional provision as explained above, contract cancellation in countries where it is possible.

Local legislation could have an impact, as in Germany currently with a tariff increase above the actual inflation level, the LT capacity holder has the option to terminate the capacity LTC. In general we do not see a strict need for LTC reset in this alternative scenario.

Any negative or positive impact on TSO from the tariff structure or size change on the international transmission caused by the introduction of the alternative scenario compared to the previous state would be compensated within the TCF, so that the regulated revenues on international transmission reach the value recorded for the previous reference period. Hence TSO revenues would not be negatively impacted by the alternative scenario introduction as a result of the assumed revenue neutrality.

A risk linked to commodity LTCs and capacity LTCs coexistence is present in this scenario, similarly to other scenarios impacting tariff structure and size or zone mergers. If the commodity LTC price with contracted delivery in the EU is not related to market price indices, any systemic wholesale price reduction decreases the commodity LTC competitiveness and puts the LTC commodity buyer into a weaker negotiating position. If the capacity contract were adjusted to lower tariffs, the producer/shipper into the EU would collect an additional rent on the unadjusted rate, now above the market priced commodity contract. Therefore any adjustment of LTC would need to be analysed also in regard to the related commodity contract and its price renegotiation power. This topic of commodity and capacity LTC coexistence would, however, have a temporary impact, because price arbitration proceedings for price adjustment due to uncompetitive pricing caused by external factors could usually be triggered between commodity LTC selling and purchasing parties in the medium term (three to five years).

With a TCF in place, we assume no new cross-border infrastructure pipeline would be financed via LTCs and the construction decision would be based on its suitability in the EU transmission network and incremental welfare gain from its construction (existence of additional transmission needs or overall cost reduction, not just a mere substituting existing routes and competing for the same flows and fees, leaving the existing transmission routes unutilised), similarly to PCI qualification. Also, if a central dispatching body was introduced, it could identify the lack of a certain piece of infrastructure in a given area and propose building it. Any projects not meeting the conditions would not be built, because independently financed projects would in the end compete with the TCF financed transmission network routes and could increase indirectly TCF financing needs.

Additional complexity is relevant for the fixed price LTCs if the tariffs are to be reset in this scenario. It would be natural to propose offering the LTC holders the possibility of switching to a new contract based on the new tariff/zone setting. The contract holder could accept this possibility if it was beneficial for them or reject it if more expensive. They would surely evaluate it on a case-by-case basis as an option with each TSO and for each contract. We assume it would not be a legally viable option to force the contract holder to switch either all contracts and TSOs or none. Hence, based on individual cases, the shippers would either accept or reject this, but with an expected negative impact on the TSOs. We expect that TSOs would be made indifferent, as their profitability will not be impacted and allowed revenues will not change (which is our applied modelling assumption), because the negative impact would be covered from the TCF that is to exist under such scenarios.

LTC adjustment discussion

Previously, gas supply in the EU Member States was usually secured by long-term bilateral contracts based on intergovernmental agreements with typically a take-or-pay provision. With the unbundling developments following the Second Package, many of those traditional contracts had to be decoupled into separate commodity supply and transmission contracts.

Regulation 715/2009 of the European Parliament and of the Council of 13 July 2009 stipulated that TSOs must have a de-coupled entry-exit system in place instead of the previously used point-to-point relations. This model represents a general improvement providing more flexibility for network users and non-discriminatory access, fostering competition and creating an EU internal gas market. An entry-exit system is a gas network access model which allows network users to book capacity rights independently at entry and exit points, thereby creating gas transport through zones instead of along contractual paths and has been further supported by a virtual trading point. In this set-up natural gas can easily change ownership, facilitating the gas market operation.

The regulation stipulated that the congestion management and capacity allocation principles shall be based on the freeing-up of unused capacity by enabling network users to sublet or resell their contracted capacities and the obligation of TSOs to offer unused capacity to the market, while those principles had to be applied to all contracted capacity, including already existing contracts.

With the implementation of entry-exit systems following the Third Package, LTC both for direct border-to-border transit transmission as well as for 'domestic' transmission, had to be integrated into the new entry-exit systems. Therefore LTC for 'domestic' transmission was adapted to the new legal provisions in most EU MSs. Transit contracts had to be transformed into entry/exit contracts in line with EU legislation. The regulation stipulated several provisions concerning the content of contracts (i.e., Art. 14, 15, 17).

There are other examples of where the EU regulation influenced the existing effective contracts, for example within electricity Network Codes (BAL NC and NC CACM), which have changed the existing system of settlement when stipulating the requirement of exclusive financial settlement of the obligations. Also in this case, the market participants had to adjust their contracts to the new EU regulation and the development towards the single EU electricity market.

A similar issue had also been solved in connection with the third party access issues according to the Second Energy Package, which aimed at elimination of discrimination in third party access to the networks, in regard to preferential access being granted to incumbents for historical long term contracts. The historical gas Regulation (EC) No. 1775/2005 imposed first use-it-or-lose-it conditions regarding transmission contracts, which included contracts concluded under Directive 91/296/EEC on the transit of natural gas through grids. Similar measures may be taken to help establishing increased competition in connection with LTC.

In addition, we are aware that in most of the long-term contracts there are clauses anticipating that market or legal circumstances can change in the course of the contract and may trigger necessary negotiations of the contracting parties, leading to contract adjustments or renegotiation.

According to the above mentioned evidence, in the previous cases the EU legislation already aimed i.a. at contractual issues and has imposed regulatory rules which influenced also the existing contractual relationships and provisions. A similar approach could be applied in the future as well. To mitigate risks concerning potential disputes, it should be ensured that the newly established legal rules are promptly and in advance consulted with the parties affected together with market participants and that such regulatory scheme comes into effect in the timeframe, which would provide sufficient preparatory space for the market participants to adapt. Moreover if there is a significant business risk in any exceptional cases, the EU legislation can establish the extraordinary possibility of the impacted business party to ask for derogation from the general regulatory rules for the transitional period. Such a derogation would be notified to the EC/ACER and approved by them so as to keep consistent EU approach to any exceptions. Similar approach was used many times in the past in the EU legislative and regulatory approach.[139]

6.1.3.5 *Other legal aspects*

The increase in the extra-EU entry/exit tariffs as a result of reduction of the intra-EU tariff reserve prices to zero could appear to be similar to import duty introduction. Nevertheless in our opinion, it cannot be seen as a duty as:

- It is a clear payment for the service of gas transmission,
- It would be derived from the original tariff payments, reflecting the regulated TSO revenues,
- The individual country based tariffs towards the non-EU countries exist already now and they also undergo regular value updates and can change from year to year.

6.1.3.6 *Infrastructure*

As per Reference Scenario.

Only the incremental infrastructure financing needs closer attention with the introduction of TCF. There needs to be an amendment to the approval process and financing of incremental capacity projects, since new capacity LTCs will not be able to cover investment costs anymore, because uncoordinated decisions about new infrastructure construction would increase the TCF financing needs. The possible solution could lie in a similar process as it is today for PCI projects. Once the project is approved by NRA(s) and EC as a necessary infrastructure, could be on proposal of central dispatching body should it be in place, it will be remunerated either through lower payment to the TCF or increased contribution from the TCF by the respective TSOs or through any other fund, or both.

6.1.3.7 *Dispatching*

Should remain as per Reference Scenario on a network level, because capacity bookings and nomination processes from a dispatching perspective will not be altered. As described earlier, capacity auctions would be kept and short-term products would cover a larger share of the revenues.

The hypothetical introduction of a central or regional dispatching body would not help the operation of the targeted market design because the gas flows would in this scenario still be determined by the nominations of the gas suppliers and TSOs would not have a large opportunity to optimise them (with the exception of netting reverse flows). Also, the technical parameters of interconnection points would remain the same as in the Reference Scenario. Therefore, we do not see it as advantageous to consider central dispatching in this case. On the contrary, it would be a key feature of the Market Merger Scenario.

[139] E.g., in the case of third party access, capacity access priority in electricity transmission.

This conclusion does not compromise our separate discussion in Chapter 3 of potential advantages of stronger TSO consolidation and independent system operator model securing more alignment among TSO operations.

6.1.3.8 Trading

Specifically in the area of trading, no regulatory changes are designed in this scenario. Due to the reduction in intra-EU transmission tariffs, higher market liquidity, supply competition and also trading volume can be expected. Otherwise, we do not foresee any significant changes occurring.

Should the EU entry tariffs increase as a result of this alternative scenario, the risk exists of a lower willingness of gas producers/importers to import gas directly into the EU on their account. They could rather intend to trade these volumes before entry into the EU and hence outside of the direct reach of EU regulation. We perceive the potential impact of this risk as rather low, because:

- Even now some of the bilateral trading or gas contract delivery happens at the EU entry points, before gas enters the EU and we have not seen it mentioned as a risk or inconvenience by market participants currently
- Some of the LTC delivery (especially for Russian gas) is already contracted directly within the EU and because capacity bookings and nominations will remain, the delivery trading point/zone for those supplies will stay as contracted for their duration, thought in this scenario with their transmission tariffs possibly impacted by this scenario
- Gas producers looking for liquid wholesale market access for the part of their production that will not be directly linked to or dependent on a particular midstreamer or end customer supplier will still have the motivation to trade at already liquid locations within the EU (like TTF)
- Given the weakening position of midstreamers in the market it is unlikely that EU companies would be willing to contract commodity LTCs for gas outside liquid trading zones and take the capacity pricing risk without being compensated for this risk appropriately. Hence, even if trading were to increase outside of the EU countries under competitively priced arrangements adjusted for the capacity costs to the destination market and taken capacity pricing risk, it should not have a negative impact on EU welfare.

6.1.3.9 Balancing (technical and commercial)

As per Reference Scenario for both the technical balancing by the TSO as well as commercial balancing by the suppliers. The only minor difference will be the access to a more liquid local trading market decreasing the balancing costs.

6.1.4 Advantages

The tariff scenario is expected to lead to increased trading within EU, and higher producer to producer competition due to reduced cross-border tariffs and reduced location spreads. These factors will lead to strong wholesale price competition. Reduced cost of transport and tariff to and from storage will decrease the costs of flexibility.

Furthermore this proposed alternative scenario should lead to improved efficiency in using the existing EU gas transmission network as location spreads decrease and contractual capacity use restrictions are reduced. All these impacts should lead to higher EU welfare as that average EU market prices should be reduced and cheaper flexibility made available.

The expectations of different regional price impacts[140] are such that initially (before considering welfare redistribution) prices should be slightly higher than currently experienced in the EU liquid area, for two reasons. Firstly, the shift of the intra-EU tariffs into the EU entry tariffs will increase the EU entry tariffs (around 50% of EU gas flows not only across EU border but also across EU countries) and, ceteris paribus, increase slightly the price in the zones with high direct gas imports (Germany, the Netherlands). Secondly, the direct connection of less liquid markets to the liquid market area can have an upward pressure, ceteris paribus, on the liquid traded price. Nevertheless, our initial calculations show that the share of less liquid areas on physical consumption in the EU is a maximum of 25%[141]; hence such an impact will be very limited. The final impact of the pricing on the EU wholesale gas market price level and on the final customer pricing, would of course depend on the gas-to-gas competition, on particular gas source, demand and supply elasticities and the reaction of the market participants to the proposed regulatory changes. Another factor will be the extent to which the EU entry tariffs are passed on through to EU wholesale market prices.

Therefore the precise welfare increase and distribution by country and market participants will be determined and analysed quantitatively by modelling.

The additional advantage of this scenario is that zone mergers can be accelerated by the new tariff setup.

6.1.5 Challenges and downsides

The main challenge of this scenario is the TCF mechanism implementation. We expect several political and administrative issues, as this will require collaboration across all TSOs and NRAs. The TCF further assumes certain regulatory convergence in order to have transparency and trust between countries/zones about regulated revenue developments for the purpose of TCF setup and operation.

Regulation harmonisation in general represents a challenge associated with this scenario.

An additional risk of the Tariff Reform Scenario is a possible capacity hoarding, because the initial capacity reserve price will start from 0 and so will be potentially cheap to contract. Nevertheless, we expect this risk to be mitigated by several of the above measures.

6.1.6 Implementation considerations

This alternative scenario cannot be implemented without the need to modify the existing legislative framework. Identified necessary modifications are discussed below.

The key point of this scenario is the creation of the TCF Fund. Currently, the compensation mechanism (e.g., between Belgium and Luxembourg) is on a voluntary

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[140] The topic of cost reflectivity could be mentioned here: once energy market virtualisation was commenced, the commercial virtual model could not necessarily reflect all parameters of the underlying physical system. Actually, virtualisation by its nature abstracts from the underlying physical system in exchange for other improved qualities – generalisation or simplification, so as to create a larger market, increased liquidity etc. In this respect, our scenario proposal is not much different from one country virtualisation – customers connected to TSO could pay lower prices before virtualisation because they were connected closer to import points and their real incurred costs are lower. Similarly to the first step, the impact on countries, because of their regional position, could be different.

[141] Data on annual demand in 2014 published by Eurogas in Statistical Report 2015 shows the following shares of gas trading hubs on the total EU gas demand (arranged by the degree of trading hub development): Established hubs (UK, NL) 26%; Advanced hubs (DE, BE, IT, FR, AT) 49%; Emerging hubs (SP, CZ, PL, DK) 13%, Illiquid hubs 11% (BG, EE, EL, FI, HR, HU, LT, LV, PT, RO, SI, SK). The degree of hub development is set forth in ACER Annual Report (The Results of Internal Electricity and Natural Gas Markets).

bilateral interstate basis, but is not supported by any EU legislation. We argue that this is such a fundamental change, especially if we consider tens of participants in the potential future TCF, that important amendment or updating of existing Regulation would be necessary to define the primary responsibilities (TCF manager), aims and tasks of the TCF. A more detailed operational description could be then delegated into secondary legislation. Similarly the Inter TSO Compensation in the electricity market, though for a different purpose is introduced in the electricity regulation itself.

The regulation amendment should be preceded by a wide-ranging debate on the operation of TCF, with the main participants expected to be TSOs (ENTSOG), NRAs (CEER), ACER and the European Commission. Concrete ideas about the operation of the TCF are presented in the previous section.

This issue has to be approached uniformly on the European level and we expect ACER to have the coordinating role and could be the TCF manager. Therefore an amendment of Regulation 715/2009 will be required.

However, in order to determine the fund flows between TCF participants, the regulatory framework for TSOs needs to be harmonised. We understand the regulatory framework in line with CEER:

- The determination of the RAB (including the evaluation of efficient costs of assets, working capital, assets under construction, stranded assets, fully depreciated assets etc.),
- The cost of capital (e.g., WACC),
- The depreciation rates,
- The application of benchmarking results and other relevant issues.

An appropriate solution would be to update the Regulation 715/2009. We understand that it is no trivial task to set a uniform approach to e.g., RAB or WACC. Likewise, we understand that it will require considerable efforts to find a consensus on the adoption of a unified approach for all TSOs in the EU. We expect optimal use of networks to divert gas flows within the EU and this might be perceived negatively by some TSOs as it affects their allowed revenues. Conversely, if some infrastructure is used more than other parts, this measure will put pressure on higher returns in this system. It is this issue that could be dealt with by a new regulation, i.e., the decoupling of revenue from flows.

The current legislative framework is based on the Third Energy Package (TEP), where a large part of the defined measures was implemented in Directive 2009/73. We expect it to be updated in connection with this alternative scenario. This means the individual aspects of the changes that can be implemented at the local level will be included in the updated Directive and then implemented in legal acts of individual EU Member States.

This alternative scenario includes an EU entry/exit surcharge or a harmonised entry/exit tariff, as mentioned above. In this context, we can imagine a situation where, for security reasons, it will be necessary to diversify the EU's gas sources. Therefore we also expect a change in the TAR NC Regulation to reflect this fact. In the current version of the TAR NC in Article 9, it is possible to apply a discount on the transmission tariff (differentiation of the pipeline/LNG tariff) in order to end the isolation of the market. If there is a zero tariff within the EU, this discount could be applied across the EU by adjusting the text in the TAR NC.

Another point to which we are expecting a legislative amendment is the CMP. In order to ensure the proper functioning of the gas market, we expect the use of more active buy-back and overbooking on the day-ahead capacities and also the LT UIOLI principle.

Since this principle is not very effective today[142] for long-term contracts as mentioned in Chapter 4.2, we expect it to be adjusted so that the unused capacity can be efficiently withdrawn. As a result, this scenario requires the amendment of Regulation 715/2009 in the CMP Section.

The last point that needs to be mentioned is the issue of capacity LTCs. According to the proposed scenario, we expect the maximum possible length of capacity reservation for the existing infrastructure to be 5 years. This is linked to a cascade reservation of capacity where, for example, for up to 5 years it is possible to reserve a maximum of 10% of the total capacity of the border point. As a complementary measure, transitional change in LTC reservation can be introduced – new LTCs longer than 5 years will have to terminate before certain date by which new tariff scenario will be implemented. Similarly, we propose that the existing capacity LTC be terminated within 5 years after the change. These proposals are not feasible in the current framework and require amendment in particular in the CAM NC Regulation (Article 11).

The gaps are summarized in the following table:

Area	Current situation	Future situation	GAP
Differentiation tariffs (LNG x pipeline)	TAR NC - Article 9; Discount to end the isolation of the market	Discount is possible in all markets due to diversification of supplies in the form of a discount on entry to the EU system. Individual tariffs at EU entry based on cost.	Amendment to TAR NC Article (9)
Calculation of surcharge on EU borders	Not addressed	ACER will determine the amount of surcharge on the basis of documentation from TSOs. This can be unified add-on to the original tariffs. If a single tariff was chosen to separate from past local tariffs, it could have an impact on entry flow IP distribution.	Amendment to Regulation 715/2009
Harmonisation of the regulatory framework	Linked to existing regulation (e.g., following from TAR NC implementation)	Key regulatory approaches harmonised to allow comparability across TSOs	Amendment to Regulation 715/2009
Share of LTC	90/10 for the remaining capacity	Set the horizon to 5 years with graduation to max 60%	Amendment to CAM NC
Contractual congestion	CMP	Active buyback/overbooking and more strict LT UIOLI	Amendment to CMP
Existence of LTC	Not addressed	Compulsory capacity LTC reduction in line with CAM NC update	Amendment to CAM NC
TCF	Not addressed	Existence of TCF, its governance and definition of key tasks	Amendment to Regulation 715/2009 and additional parameters to define in secondary legislation
Local regulations	Single market is goal	Revision of the Directive	Directive 2009/73

[142] Based on CMP Monitoring Report (ENTSOG 2016), based on LT UIOLI no additional capacity was provided nor reallocated.

Area	Current situation	Future situation	GAP
Segregation of revenue from flows	TSO revenues are linked to real flows	Actual bookings and flows do not determine revenues. Revenues are broken down on an idealised plan	A new regulation

Table 20: Summary of gaps of the Tariff Reform Scenario

6.1.7 Impact on stakeholders

6.1.7.1 Gas producers

- Their transmission cost related risks would be decreased within the EU. Gas producers should only ensure to contract the capacity to deliver their gas to the EU entry border. Zero intra-EU tariffs will increase producer to producer supply competition on the European market by eliminating the tariff pancaking effect. Under the assumption of no congestion, all producers/importers will be competing in price with any other importers who enter the EU market, because no tariff fees will separate them on the internal EU market.
- Producers will be affected by this alternative scenario in different ways, depending on the conditions under which they supply gas to their customers in the EU. Those who currently deliver gas at the EU entry borders will not be fundamentally affected by this scenario, as the consequences of the proposed scenario apply within the EU.
- Conversely, to producers with contractual delivery points within the EU who are at the same time transmission capacity holders, this proposed scenario may constitute a hurdle, as they would compete with other market participants for the available transport capacity, which may be different from today.
- Producers generally face the risk of increased costs due to a higher tariff on entry into the EU. However, we do not expect these tariffs to have a deterrent effect. We assume that any re-routing of resources outside of the EU would be much more expensive than a higher EU entry tariff, which, in addition, would be the only one to be paid by producers and would allow them to deploy their gas throughout the European market.
- The possibility of accumulating reserved capacity on frequent cross-border points or the chance of congestion appears to be a certain risk for producers, as well as other network users. However, this risk should be eliminated by thorough application of CMP principles and reduced proportion of capacity available for long-term booking.
- Another risk that producers would face is limited ability to use capacity LTCs to support their commodity contracts. However, at present, we already see a changed market approach to the LTC, where producers enter into capacity and commodity contracts for a shorter period of time than they used to in the past and make use of new market strategies and products such as delivery at VTPs at the current market prices. The major mitigation of this risk would be a transparent and predictable EU-border tariff setting, so that short-term capacity bookings even for longer-term commodity contracts are of no material price and availability risk.

6.1.7.2 Midstreamers

- Midstream companies could face higher competition because producers and importers, once they enter the EU, can deliver the gas to any hub at zero price.
- On the other hand, pancaking effect should be eliminated.

- Some market behaviour will no longer be a viable business strategy, such as capacity hoarding, because alternative routes will be available to all midstreamers.
- If more than one competitor competes on the same routes, there is a real risk of capacity hoarding or contractual congestion in the current market setting. As described in the passage devoted to producers, we anticipate an effective use of CMP principles, which is supposed to prevent more congestion.
- However, as a significant advantage, we perceive the access to practically any market in the EU with the minimum cost. This aspect of the scenario should avoid booking transmission capacity that is not supported by future commodity flows and thus limits the long-term booking related sunk costs. If there are several alternative routes that are comparable in terms of cost, there is no reason to hoard surplus capacity.

6.1.7.3 TSOs

- The biggest risk for TSOs is the threat to the allowed revenues. Assuming an effective TCF fund to ensure revenue neutrality (compensation payments), this scenario should be neutral for transmission network operators.
- We understand that creating and agreeing on the correct operation of the fund would be challenging, but the operation of the fund itself should not be complicated.
- TSOs' revenue composition would be affected by splitting assets to domestic and transit and new compensation payments.
- More dynamic capacity calculations would be needed.
- Asset utilisation may change due to changing flows, especially if a central dispatching body is introduced which will be targeting the most economic asset utilisation (however introduction of central dispatching is not necessary precondition for proper functioning of this scenario). If no central dispatching is in place, the gas flow will be determined by shipper's nominations. The change in asset utilisation will raise the question of the remuneration of less utilised assets. This issue will have to be considered from an EU level taking into account future gas consumption, gas flows or national and regional/EU SoS point of view to allocate costs on customers.

6.1.7.4 Hubs

- Expected increased volume of tradable gas and increased liquidity across the EU should benefit the trading platforms. Hub development and market mergers would be boosted by the implementation of this proposal. This scenario therefore constitutes an opportunity for business platforms.
- It is expected that wholesale prices on different hubs will converge because locational spread caused by transportation tariffs will disappear.

6.1.7.5 Customers

- Customers would face reduced risks from downstream market foreclosure especially in those market zones more exposed to dominant suppliers.
- Due to removal of barrier for market participants to be active on more hubs (pancaking problem), end users should expect lower final prices because more competitive environment will be established.
- Transmission cost will be equal for all EU customers. This may be disadvantage for those customers who are close to the EU-entry in case no additional fees are implemented on domestic tariffs for other customers reflecting usage of upstream infrastructure.

- The main goal of the Tariff Reform Scenario is to increase end-user welfare by lowering wholesale prices, which are projected into lower retail prices.
- We also expect the opening of the market to other traders, especially where end customers do not yet have the opportunity to choose their supplier. Increased competition should also contribute to a positive overall impact on end customers.
- Opening up the market to EU-wide competition should also improve security of supply.

6.1.7.6 NRAs

- NRAs will have to develop common rules on TCF and harmonised methodology for setting allowed revenues. A greater degree of cooperation would be necessary at the level of the regulatory framework (e.g., RAB, WACC, etc.). This can be seen as an opportunity for regulatory framework harmonisation.
- Also, a methodology for designation of transit and domestic assets will have to be created.
- Determination of allowed revenues would remain at the level of national NRAs.

6.1.7.7 Neighbouring countries

- Gas flows may change in certain areas, when shippers will no longer be motivated to use the cheapest tariff routes (e.g., gas from Germany destined for Slovakia or vice versa can be routed through the Czech Republic or Austria). Shippers' behaviour will thus influence asset utilisation in the region where more transmission routes are possible.

6.1.7.8 Summary of impact on stakeholders

Summary of impact on stakeholders, part 1/2

	Producers	Midstreamers	TSOs	Hubs
Higher EU Entry/Exit tariffs	Neutral – On average no impact.	No effect	No effect	No effect
Zero cross-border tariffs within EU	Neutral – Larger producer to producer competition, but also easier access to new EU markets	Positive - greater market access and ability to use wider arbitrage opportunities	Positive - zero tariffs will lead to finding available routes, TSOs will not have to face congestion, uncertainty covered by TCF	Positive - Increased trading volumes
Regulatory frameworks	Neutral - Impact on capacity reservations, easier access to alternative routes, negative impact on LTCs	Positive - easier access to capacities and alternative shipping routes	Neutral – Various impacts on different TSOs, on average TCF should increase certainty	No effect
TCF	No effect	No effect	Neutral - The basis is to secure existing revenues	No effect
Hoarding	Negative - Zero tariffs could lead to over-booking, importance of CMP	Negative - Zero tariffs can lead to over-booking, importance of CMP	No effect	No effect
Congestions Contractual/Physical	Positive - Easier access to capacities and alternative routes	Positive - Easier access to capacities and alternative routes	Positive - With easier access to alternatives routes	Positive – Less congestion supports market resilience and liquidity
More efficient UIOLI both FDA and LT	Positive - Effective availability of unused capacity	Positive - Effective availability of unused capacity	Neutral - Varying impact on congestion fees between TSOs, but the total effect expected to be zero	Positive - Higher liquidity
LTC capacity	Negative – No LTC booking possible for new contracts and preferably also none for old ones	Neutral - In line with the decline of commodity LTC	Neutral - Lesser revenue security for the long term, uncertainty covered by TCF	Positive - Higher liquidity

Table 21: Impact of Tariff Reform Scenario on stakeholders (1/2)

Summary of impact on stakeholders, part 2/2

	Customers	NRAs	Neighbours countries
High EU Entry/Exit tariffs	Neutral – Impact on individual zone prices can differ, though on average expected improvement.	No effect	No effect
Zero cross-border tariffs within EU	Positive - More liquid market and increased producer competition lead to general price decrease	Neutral - Tariff calculations remain on a local basis	No effect
Regulatory frameworks	No effect	Negative - Harmonisation of the regulatory framework leads to less space for NRAs	No effect
TCF	No effect	Negative - Weaker NRA position	No effect
Hoarding	No effect	No effect	Negative – Capacity hoarding could reduce real IP usage
Congestions Contractual/Physical	Positive - Decreased congestion shall help liquidity	No effect	Positive - Lower congestion will help efficient network use
More efficient UIOLI both FDA and LT	Positive - Ensuring security of supply and liquidity	Neutral – ensuring efficiency	Positive - limitation of unavailability
LTC capacity	Positive - Ensuring security of supply	No effect	No effect

Table 22: Impact of Tariff Reform Scenario on stakeholders (2/2)

6.2 Trading Zone Merger Scenario (Market Merger)

This scenario aims to analyse the possibility of merging existing market zones. It should increase market liquidity by putting together zones with suitable network topology that offer synergies when merged into one zone. A merged zone is one possible way of increasing network use efficiency and reducing contractual congestion, eliminating location spreads and increase liquidity. It would have one entry-exit system, one trading point with one wholesale price and common balancing regime[143]. Creating bigger or regional zones is conditioned by the sufficient and suitable infrastructure and incentivised TSO cooperation and zonal TCF creation. When infrastructure is not

[143] Technical balancing by TSO as well as commercial balancing by traders.

sufficient, zone merger would be either costly or connected with additional capacity restrictions.[144]

6.2.1 Introduction and motives for considering this scenario

Zone merging is another possible alternative regulatory scenario, which can increase market liquidity and mitigate location spreads among several zones and strengthen the gas-to-gas competition. A well-connected trading zone will have more producers and suppliers active on the market, larger portfolio of usable assets (gas storage, number of pipelines or LNG terminals) and also larger and more diverse consumer portfolio. These factors will increase the zone market liquidity and depth, and also enable market zones to share synergies more efficiently (at lower cost), e.g., landlocked countries may directly benefit from the LNG terminals.

This simplified market design could on the other hand reduce the extent to which tariff setting is cost-reflective. This abstraction from cost reflectivity is not a new tendency and is to a certain degree present in any virtual market design already implemented at national level. Modelling of this scenario shall indicate to which extent this market design abstraction could add welfare or rather bring more adverse effects especially on the neighbouring unmerged zones.

In this scenario, we will analyse the welfare impact of possible zone mergers within the EU. We propose several market zones initially as potential candidates for zone mergers and we will simulate this through the modelling analysis so as to discover whether the mergers provide benefits or rather create new congestion. Moreover we will also assess what impact the zone merger has on neighbouring countries and/or zones. within the EU The modelling analysis will be based on simplified gas transmission network topology and physical parameter modelling. The modelling will not be able to assess investment costs for necessary new infrastructure development. Hence, we focus on zone mergers where top level infrastructure topology in our view could make it an economical zone merger. Without an exact network capacity model reflecting contractual conditions and taking into account any additional possible measures (e.g. specific capacity products, redispatch of flows, load flow commitments, adaptation of capacity rights), it is not feasible to exactly predict the final capacity situation of the selected trading region and estimate the investment costs necessary to implement the respective zone merger.

The trading zone merger will in comparison to the Reference Scenario remove any direct trading barrier by the elimination of transmission tariffs and capacity booking within the trading zone (on former cross-border interconnection points) and will establish one common wholesale price within each merged zone and enable free flexibility transfer within the merged zone. Traders will be able to use the flexibility of the entire merged zone for their balancing at no additional cost, thus sources will be used more efficiently compared to the Reference Scenario.

In a similar way pipeline use optimisation will exist, not only from the side of traders, but also from the side of the TSOs. Within one zone consisting of two countries, traders will merge their original country portfolios into one, without distinguishing whether the customer from the first country is actually supplied from the first or second country. Within a zone, TSO cooperation can be strengthened, so that the TSOs are fully motivated to explore the system and operational synergies. As a condition for zone merger and revenue redistribution among TSOs, a zonal TCF would need to be established.

[144] Indicative estimates of necessary infrastructure investments for French zone merger or for German zone merger consideration are available, as well as experience from merging former German zones into bigger NCG and Gaspool zones (capacity limitations and conditional capacity products offered).

Creating several trading zones within the EU would make it easier for traders to choose the right transit route across Europe and also across otherindividual zones, because they book a route only through a reduced number of zones. In many cases most of the transactions will be within the same merged zone, so route planning will be a purely technical operation for the individual TSOs. This will allow for a more efficient use of the network within the merged zone. TSO dispatchers will be able to better provide for the flow of gas through the merged trading zone.

It should be noted that a similar market arrangement has already been tested in practice. The trading region created by merging GRTgaz South and TIGF areas was set up on 1 April 2015 in France and is known today as the Trading Region South.

The final price level and distribution of welfare among the participatingmerged zones depends on several factors (such as different original market liquidity, market size, gas source availability and market structure) and needs to be modelled for more insight. Nevertheless, if economic welfare is improved by the market merger, the welfare redistribution into participating zones can be performed via TCF similarly as in the Tariff Reform Scenario.

6.2.2 How this scenario addresses market inefficiencies

1.	Transmission tariff levels and structure	Zero cross border tariffs and no capacity booking within merged zones will eliminate tariff pancaking, location spreads and allow free gas flow and flexibility exchanges. Nevertheless, location spread will remain between the newly merged zones and neighbouring zones and its impacts shall be thoroughly analysed within the modelling part.
2.	Regulatory and contractual restrictions	This scenario assumes that there is sufficient infrastructure within the merger zones to ensure smooth flows. In case some cross-border point within the merged market was contractually congested before market merger, different routes may be used after merger.
3.	Physical restrictions	This scenario assumes that there is sufficient infrastructure within the merger zones to ensure smooth flows. In case some cross-border point within the merged market was physically congested before the market merger, different routes may be used after the merger. Similarly, when several cross-border points exist between the merged zone and the other zones, the congested cross-border point can be circumvented by another route.
4.	Infrastructure use efficiency	We expect a more even distribution of the flow across the merged zones if there are several available cross-border points among these individual zones that could not be utilized in the state before the merger. In case of merging zones that are part of one major infrastructure complex, we do not expect any major changes.

		Zero intra-zonal tariffs will decrease the price of sourcing flexibility via reduced location spreads and cheaper flow substitution within merger zones. Harmonizing the gas flow through a centralized approach (one responsible TSO) may also improve utilization of the existing infrastructure within the merged zones.
5.	EU-level market concentration	Zero intra-zonal tariffs will increase producer to producer supply competition in the merged market. We expect that increased competition in merged markets will positively affect neighbouring locations within the EU.
6.	Local specifics in regulation and limited transparency	Because introduction of TCF is perceived in this scenario, an increased level of economic regulation harmonisation will be needed like in the Tariff Reform Scenario.

Table 23: Trading Zone Merger Scenario addressing market inefficiencies

6.2.3 Main amendments to the Reference Scenario

6.2.3.1 Entry-exit zones

In this scenario we analyse several possible zone mergers while leaving several market zones within the EU unchanged. The decisive criterion taken into account when formulating new trading areas within Europe, was a potentially suitable infrastructure topology inside the newly-proposed merged zone so as not to require additional substantial infrastructure investment or capacity use restrictions[145]. Based on the modelling results depicting the flows and expected contractual and physical congestion, we will propose further amendments to the analysed zone mergers or suggest additional zone mergers not yet discussed here. Please note also that the trading zone merger of the current French zones is already included within the Reference Scenario. The new merged zones included in this scenario which will be modelled for the welfare change are:

[145] We also account for the planned national level market mergers scheduled for France and Germany, where political will was the main driving force.

Figure 46: Proposed regional zones

i. Spain, Portugal

The idea to merge the Spanish and Portuguese natural gas markets is not new. The reasons for such a merger are: (i) the significantly smaller gas market in Portugal (consumption of 55 TWh in 2016) will gain liquidity by merging with the larger Spanish market (consumption of 321 TWh in 2016), (ii) the geographical situation of both countries and (iii) benefits for third countries, in particular, improved interconnection between Spain and France leading to better access for Central European countries to LNG terminals in the Iberian peninsula.[146]

Variable options for merging these two markets were analysed in ACER 2014 specifically: (i) market area model, i.e., full market integration, (ii) trading region model and (iii) wholesale market with implicit allocation of capacity. Based on the results of public consultation, most of the market participants agreed that market integration (market area model) would be positive for both countries.

Since then, the first steps towards integration of these two markets have already been pursued. In December 2015, the MIBGAS exchange began trading. On this exchange the Spanish and Portuguese markets are combined into a single Iberian wholesale natural gas market. In October 2017, 6.25% of the Spanish natural gas demand was traded on MIBGAS. The number of participants, as well as the average daily traded volume, has risen in the last year (from 50 registered participants to 63 and over 40%, respectively).[147] Recently, it has been agreed to develop a natural gas futures market which will begin operating in January 2018. These

[146] According to the Study about Models for Integration of the Spanish and Portuguese Gas Markets in a Common Iberian Natural Gas Market by ACER et al. (2015)

[147] http://www.mibgas.es/en/gas-markets/information-company/relevant-information/news/mibgas-reaches-6-25-spanish-natural-gas-de

measurements should help to solve one of the issues highlighted in the ACER 2014 study, namely lack of liquidity and transparency in the Iberian wholesale gas market.

In contrast to other proposed market mergers (most notably Romania with Bulgaria and Baltics with Finland), the security of supply of the merged countries is not the key element in the case of Portugal and Spain. Both countries import a significant part of their gas consumption via LNG which provides desirable diversification of sources.

To sum up, going forward the merger of Iberian markets appears probable, as the first steps have been already undertaken and the key stakeholders are inclined towards the merger.

ii. Netherlands, Germany, Belgium, Luxembourg, the Czech Republic, and potentially Slovakia

To our knowledge, a zone which would comprise Germany, the Benelux countries and the Czech Republic (not to mention Slovakia) has not been seriously discussed. However, partial mergers within the group of these countries have been considered or even occurred.

An already completed merger within the discussed states and at the same time the first ever gas market integration (featuring a single VTP, entry-exit zone and balancing zone) between two EU Member States occurred in October 2015 when Belgian and Luxembourgish (BeLux) gas markets merged, following approximately three years of close collaboration between the concerned TSOs and NRAs. The main benefits of this merger stated by its key stakeholders are (i) greater liquidity at the Belgian Zeebrugge Trading Point, (ii) consequent lower gas prices for consumers and (iii) improved security of supply for Luxembourg. The merger was accompanied by the introduction of a conditioned capacity product between NCG and ZTP from the Remich (Luxembourgish-German) interconnection point. In preparation for this merger, Belgian and Luxembourgish authorities established a joint entity to manage the commercial market-based balancing of the integrated market, while physical balancing remained the responsibility of individual TSOs.

The BeLux merger was completed without investments into "tangible" gas infrastructure and did not affect the amount of firm capacity. The loss in revenues from tariffs between Belgium and Luxembourg is being compensated between the TSOs and is covered by TSO exit tariffs from the BeLux so that consumers in the zone are not affected. The merger was suitable thanks to the zone's strong links to neighbouring gas markets which help reduce the risk of price isolation. Yet, lessons learned from the BeLux merger (CREG, 2016) suggest that a detailed cost-benefit analysis has to be conducted before starting, as costs of transfer capacity may outweigh the benefits of an integrated market, and that cost-neutral compensation of lost revenues from intra-zonal transmission points may be challenging.

Strong cross-border interconnections of the BeLux zone make potential further mergers with the Dutch or the German zones meaningful. Such mergers would help overcome the gap in infrastructure between Gaspool and NCG via the Netherlands and, possibly, via the Czech Republic through the Gazelle pipeline. Slovakia could be a further part of this zone in this scenario, because it is well-connected to the Czech Republic, though via only one strong pipeline system.

Expert opinion concerning potential for further national or cross-border market integration and its implications for the German market, conducted on behalf of the Bundesnetzagentur in 2016 by Wagner, Elbling & Company, examined separate options which in sum cover the geographical scope of the proposed zone with the exception of Slovakia (i.e., it discussed a merger of the German zones, the German zones plus the Netherlands, the German zones plus the Netherlands plus BeLux and the German zones plus the Czech Republic). It concluded that irrespective of the market zone chosen, integration is advisable, at least in the areas of security of supply, storage and tariffs. Further, any proposed market integration seeking to support the NCG and Gaspool markets should include at least these two market zones and the Dutch TTF.

iii. Romania, Bulgaria

Historically, there have been no significant attempts (or discussions at least) to merge Bulgarian with Romanian natural gas markets (in comparison to e.g., Spain and Portugal). We argue that merging these two markets could increase welfare as well as security of supply in the region.

The main reasons why there were no market merger discussions in Romania and Bulgaria in the past are listed below. All of these reasons were significant restrictions for gas trading in the region. Firstly, the infrastructure development in general in the south-east of the EU has been and still is one of the poorest compared to the rest of the EU (which is expected to be improved in the coming years as significant part of the planned infrastructure projects are in this region). Secondly, Romania is currently being investigated by the European Commission as to whether its national TSO Transgaz has abused its dominant position and hindered gas exports to neighbouring countries. Thirdly, the liberalisation of both markets has been lagging behind the rest of the EU, but significant improvements have been achieved recently, on both Romanian and Bulgarian sides.

Going forward, improvement is expected alongside all of these categories. In 2016 a new interconnector between Bulgaria and Romania was commissioned. Moreover, further infrastructure is planned and also included in the Reference Scenario, such as an interconnector between (i) Bulgaria and Greece and (ii) Bulgaria and Serbia. Also, according to recent news, the countries in the region are willing to cooperate more in the future. There have recently been negotiations between Bulgaria and Romania on cooperation in the energy sector[148] and there have been discussions on a Vertical Gas Corridor between Bulgaria, Romania, Greece and Hungary.[149]

All of the measures above are expected to increase liquidity in the region and also increase supplier diversification. For example, Bulgaria currently imports more than 90% of its consumption from Russia, which is expected to significantly decrease after commissioning the projects above (e.g., via supplies from Romania).

The market merger of Bulgaria and Romania would establish a strong local market area with a combined consumption of over 140 TWh (based

[148] http://www.bta.bg/en/c/DF/id/1646686

[149] http://www.icgb.eu/gas-companies-signed-memorandum-of-understanding-on-the-vertical-gas-corridor

on 2016 figures) which would make this merged area the biggest market in the southeast region of the EU. Such an area is expected to be advantageous especially for Bulgaria as it will be merged with the third largest natural gas producer in the EU (Bulgaria's gas market amounts approximately to one quarter of Romania's market), but also Romania is expected to profit due to increased customer base for its domestic producer. Also, the neighbouring countries (such as Greece, Serbia or Hungary) are expected to profit from the regional higher liquidity. The proposed merger of Bulgarian and Romanian gas markets, if successful, can be perceived as the first step for a wider regional merger including also Hungary and Greece.

iv. Lithuania, Latvia, Estonia and Finland

A regional gas market in the Baltics is currently being planned, with expected implementation in 2020, according to the declaration of Baltic Prime Ministers in December 2016. The merged market should comprise Estonia, Latvia and Lithuania. In the second phase, the Finnish market is also planned to merge with this zone. By 2020, the region should establish common market rules, a single transmission tariff regime and common pricing and possible socialisation of costs related to infrastructure, i.e., to the LNG terminal and gas storage facilities.

The negotiations leading to the planned merger into a single trading zone emphasised numerous advantages of the merger, namely (i) more efficient and less distorted gas flows in the region and availability of the cheapest available gas in any part of the region, as a result of a removal of IP tariffs, assuming limited congestion, (ii) greater liquidity, where contractual congestion would otherwise limit gas flows in individual zones, and (ii) improved SoS through better cooperation and higher liquidity. In addition, shippers in the lower-priced country within a single zone would be selling higher cross-border volumes.

Yet, several drawbacks have been foreseen, such as higher TSO costs as a result of increased demands on redispatching, especially when congestion occurs, and higher network investment costs associated with the merger.

Existing infrastructure is not completely suitable for a full merger of the Baltics. The Baltic region sees the most significant congestion in the winter months in the direction south to north, when LNG is relatively cheaper. Similarly, Lithuanian LNG affects congestions in the summer when it constitutes a source of major flows of gas into Latvian gas storage.

However, as the Baltic Regional Gas Market Study (Frontier Economics, 2016) points out, major congestion in the merged zone, after all necessary investment is made, would be unlikely and so the main benefit resulting from this zone merger is related to an efficiency gain resulting from the removal of cross-border tariffs. The benefits of the merger for the Baltics were concluded to outweigh the costs.

In addition, a full merger including Finland requires completion of the interconnection between Estonia and Finland. The bi-directional Balticconnector pipeline (expected commissioning in 2020) would be mostly used for transportation of LNG from the Baltics when price is beneficial. Together with capacity enhancements on Latvian-Estonian and Lithuanian-Latvian borders, this infrastructure improvement would mitigate the likelihood of congestion and facilitate the functioning of a full zone merger including Finland.

Although the price benefits of LNG may not persist, other benefits of the merger should prevail. These encompass improved security of supply (by making available an alternative to Russian gas, namely for Finland, Latvian gas storage will be accessible for all countries without additional surcharge) and increased competition in gas supplies. In addition, an LNG terminal in Estonia or reinforced interconnections within the Baltics are considered in order to alleviate congestion and increase diversification and security of supplies.

6.2.3.2 Tariffs

As per Reference Scenario.

Only tariffs at the merged zone external border will be changed. They will be increased (in a similar way as in the previous Tariff Reform Scenario) so as to collect the same TSO revenue, which will be foregone by abolishing the transmission tariffs for the former cross-border capacities that are now within the merged zone. The tariffs within the new merged zones and its reservation process will be cancelled. Domestic exit tariffs will not change.

TCF will play a crucial role in this scenario and will be established and administered separately for each zone. Similarly to our discussion of TCF in the Tariff Reform Scenario, economic regulation, therefore, will need to be harmonised inside each merged zone. TSO international transmission revenues will be fixed for each TSO in the zone from the preceding reference period. Fees from entry and exit interconnection points collected in the fund will be redistributed to the relevant TSO to reach the original allowed revenues. This scenario again does not change TSO revenues and thus the TSO is revenue neutral.

Preferably the NRAs should service the TCF, similarly to the Tariff Reform Scenario.

Illustrative market design impact of the Trading Zone Merger in comparison to the current situation

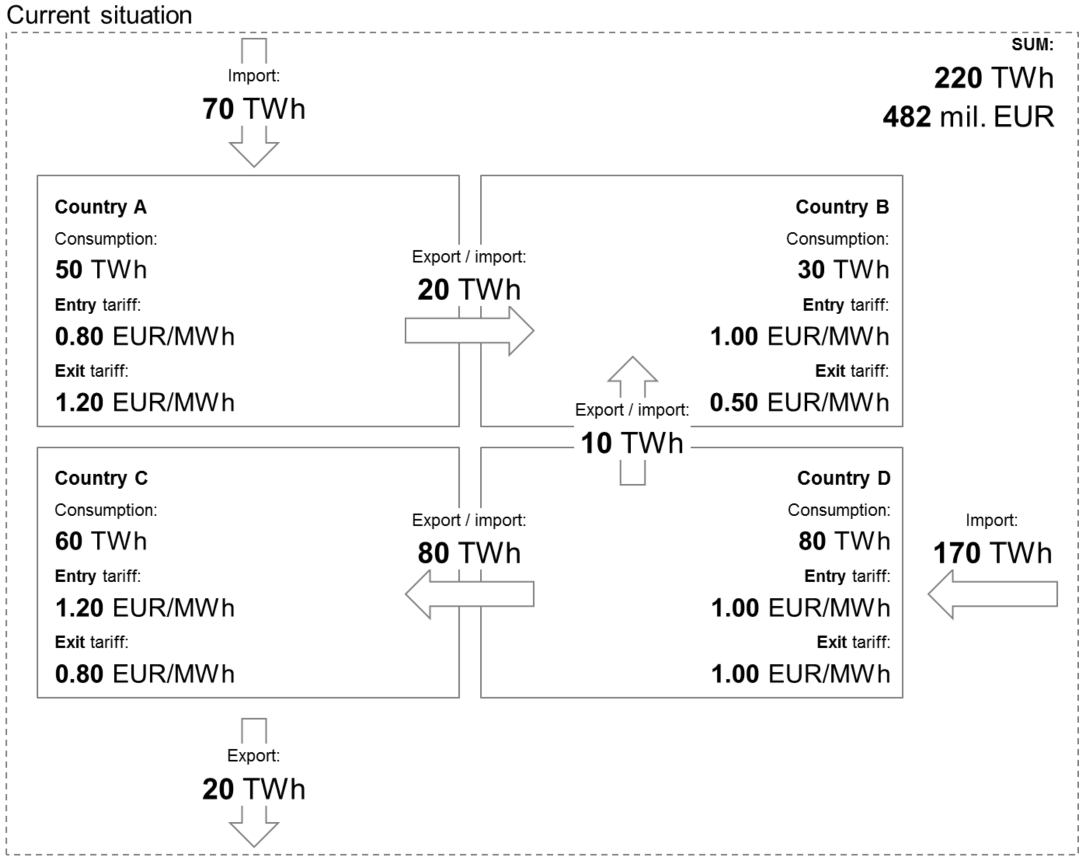

Figure 47: Current situation

Source: EY

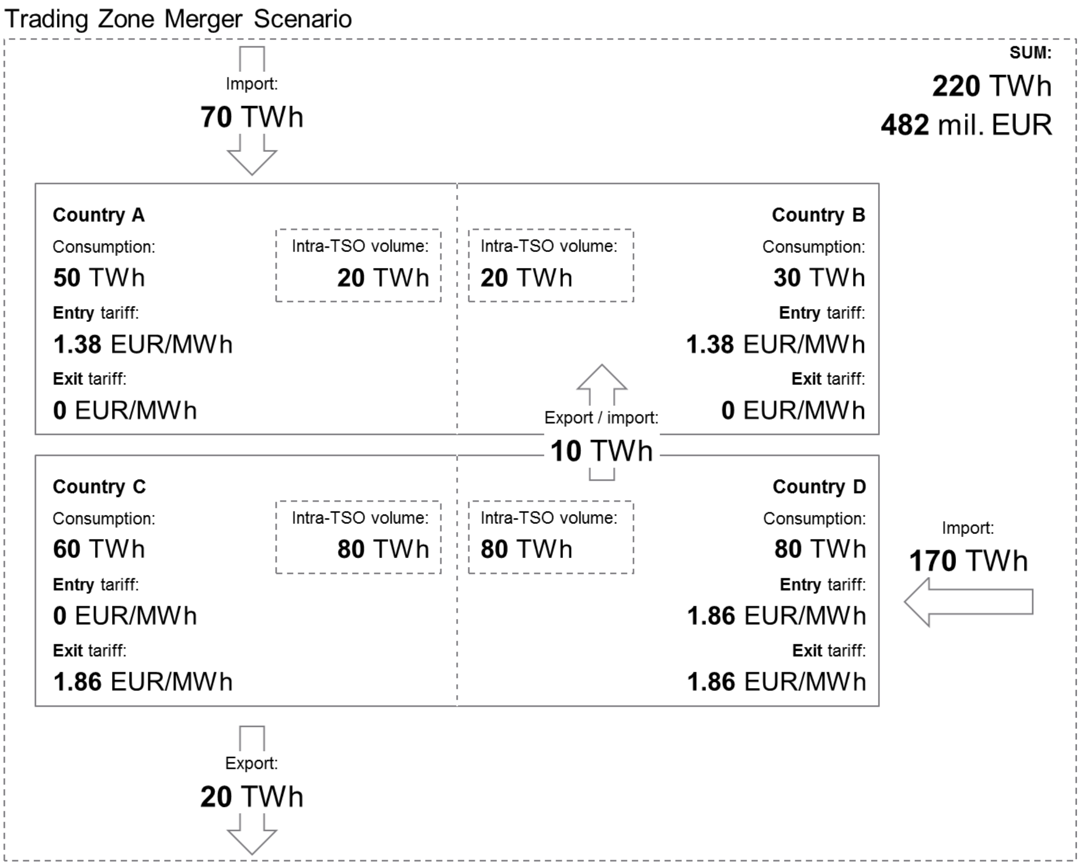

Figure 48: Trading Zone Merger

Source: EY

6.2.3.3 Economic regulation

As discussed above, a zone-wide TCF mechanism needs to be introduced, hence it is beneficial to harmonise a regulatory approach to setting allowed revenues (harmonisation of the approach to RAB and its depreciation, factor of efficiency, OPEX size, WACC, necessary infrastructure remuneration), because part of the revenues in some countries will be covered through the TCF and it is necessary to ensure that only eligible cost, reasonable profit or efficient size of the infrastructure (with regard to SoS requirements) is covered. If the approach to allowed revenue calculation were not harmonised, TSO and also NRA could have a motivation to either increase allowed revenues outright, or only increase the part of the allowed revenues covered by the TCF.

Agreement between national regulatory bodies or even inter-governmental agreement will be needed for this scenario. We do not consider creating a new regulatory body to oversee the functioning of the TSOs and TCF at zone level as necessary; increased regional cooperation of NRAs should be sufficient.

6.2.3.4 Capacity LTC

Current capacity bookings inside the zones will not have any commercial justification and will not be used and only bookings on the interconnection points to other zones will be possible. Therefore LTCs for interconnection points within the merged zone will not actually be usable and hence the related contractual duties will cease to exist.

6.2.3.5 Infrastructure

As per Reference Scenario.

New pipeline investments have to be coordinated within the merged zone among TSOs and NRAs because they will directly impact the TCF and can impact the existing flow of competing pipelines.

6.2.3.6 Dispatching

Because there will not be any nominations within the merged zone, this role shall be given to either one of the TSOs, who will be responsible for joint dispatching within the merged zone of gas flows or to a third party in the form of central dispatching. TSO or a dispatching body will have to book and nominate on the interconnection points within the merged zone. TSOs dispatching will have to handle the dispatching automatically within the merged zones. For the strengthening of TSO cooperation, central dispatching for the merged zone could be considered even in a stronger form, similar to an ISO in the unbundling. This central dispatching could perform operational and dispatching duties for multiple TSOs, help with TSO interconnection parameter definition and help to identify interconnection bottlenecks and investment needs within the merged zone, though the individual TSO assets would be owned by each TSO (in more detail described in Chapter 3.10). For our modelling exercise, the exact form of TSO coordination is not material.

Because one balancing regime is assumed to be common for the trading zone merger, balancing will need to be performed either by one TSO or within a predefined TSO cooperation framework.

6.2.3.7 Legal aspects

Taxes for the wholesale hub trading (if only one hub/platform exists in the zone) will be paid in the country where the operator is registered.

Contractual adjustments in the LTC, due to commercial nonexistence of the former interconnection points within the newly merged zones, have to be managed, as we indicated above in Section 6.2.3.4.

6.2.4 Implementation considerations

Bottom-up market mergers are not restricted in the current regulatory framework but are not incentivised. Currently, they mostly occur on a national basis and require an agreement on the common tariff settings, regulatory harmonisation, NRA cooperation and TSO coordination procedures.

If welfare benefits are identified not only at the regional level, but also at the EU level, the EC should support the market mergers by establishing a basic framework and rules on common tariff setting, regulatory harmonisation, NRA cooperation and TSO coordination procedures to provide a baseline for individual negotiations.

The legislation relevant to the proposed mergers is Directive 2009/73/EC (introduction of rules for compensation mechanism, efficient TSO cooperation and introduction potentially new network code on compensation mechanism), Regulation 715/2009 (update on potential list of merged markets) and amendment of TAR NC (harmonisation of allowed revenue calculation, especially transit and domestic flows related infrastructure).

We see determination of the main regulatory responsibility for the merged zone as crucial, which is easily determined in the case of an intra-national merger but might be more difficult to agree between several countries or NRAs. Yet the Belgian-Luxembourgish example shows that when the will to apply the new arrangement exists, a cross-border merger can be successfully implemented.

An alternative to bottom-up induced mergers is a top-down approach, which could be taken when clear EU-wide benefits from the reduction of market zones are identified. A similar solution has been applied in the electricity sector, where so-called common bidding zones have been established on the basis of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation) and also of the Decision of the ACER No 06/2016 of 17 November 2016 On the TSOs Proposal for the Determination of Capacity Calculation Regions[150].

CACM Regulation laid down a range of requirements for cross-zonal capacity allocation and congestion management in the day ahead and intraday markets in electricity. These also include specific requirements for capacity calculation regions which, according to the definition in Article 2(3) of the CACM Regulation, are the geographic areas in which coordinated capacity calculation is applied.

Under Article 9(1) and (6)(b) and Article 15(1) of the CACM Regulation, TSOs are required jointly to develop a common proposal regarding the determination of capacity calculation regions and submit it to all regulatory authorities for approval. Then, according to Article 9(10) of the CACM Regulation, the regulatory authorities receiving the proposal on the determination of capacity calculation regions shall reach an agreement and take a decision on that proposal, in principle, within six months of receipt of the proposal by the last regulatory authority. According to Article 9(11) of the CACM Regulation, if the regulatory authorities fail to reach an agreement within the six-month period, or upon their joint request, the Agency is called upon to adopt a decision concerning the TSOs proposal and shall adopt a decision concerning the submitted proposal within six months and in line with Article 8(1) of Regulation (EC) No 713/2009.

The general possible approach could be based on formulating criteria for market area mergers and cost/benefit calculation, harmonisation of relevant regulatory approaches and pre-establishing basic rules to draw from in the case of market mergers. Once these steps have been taken, a general deadline for bottom-up approach can be set, specifying what would be the next steps if the bottom-up initiative was not present, e.g., that ACER could approve the bottom-up approach and determine the set-up of the remaining areas.

Non-regulatory gaps

Access to a regionally merged virtual trading point would require additional commercial and/or technical measures due to currently unsatisfactory cross-border capacity between some countries in the merged zones. This would lead to additional costs, e.g., in the case of bottleneck identification. We also expect some additional administrative costs to occur.

Also, the expected increase in cross-border tariffs between the merged zones and neighbouring zones might in turn require higher collateral for capacity bookings among the trading zones, compared to the Reference Scenario. So at least partial offsetting of

[150] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf

the advantage of reduced collateral is needed for operations within the trading zone as described above.

The Trading Zone Merger scenario could lead to significant implementation costs if zones without suitable network topology were merged. Further, thorough transmission network modelling reflecting all relevant technical and commercial limitations would need to be performed to fully quantify potential bottlenecks and connected implementation costs.

The gaps for the bottom-up approach are summarised in the following table:

Area	Current situation	Future situation	GAP
Virtual trading point	There is at least one trading point in the zone	Create a common virtual trading point	Adaptation of local legislation (deletion of the original point and creation of a common new one)
Abolition of tariffs within merged zones and setting new tariffs	The tariffs are set by an individual NRA	Tariffs will be calculated together for the merged zone in NRA coordination	Adaptation of local legislation (formal cancellation of intra-zone IPs for capacity booking, common procedure for tariffs calculations)
Commercial balancing	Balancing of a single zone	Commercial balancing at the level of the merged zone, cooperation of participating TSOs	Adaptation of local legislation (Common Zone Balancing)
Physical Balancing	Balancing of a single zone	Individual TSOs remain responsible for their network	No adjustment required
Regulatory framework	Individual countries have an individual approach	Harmonised regulatory approach	Adaptation of local legislation (unification of regulation)
Contract documentation	Individual for each zone	Necessary Settlement Contracts, Balancing Rules, Reallocation of Balancing Payments	Adaptation of local legislation (harmonization of principles)

Table 24: Summary of gaps of the Trading Zone Merger Scenario (bottom-up approach)

The gaps for the top-down approach are summarised in the following table:

Area	Current situation	Future situation	GAP
Create merged zone	Not addressed	Probably ENTSOG (ACER/EC) will issue recommendations on which zones are appropriate to merge, NRAs will conduct economic tests	Updating Regulation 715/2009 - imposes an obligation to regularly compile a potential list of merged zones Inter-governmental agreement needed.

Area	Current situation	Future situation	GAP
Abolition of tariffs within merged zone and setting new tariffs	The tariffs are set by an individual NRA	Tariffs will be calculated together for the merged zone	Adaptation of local legislation
Commercial balancing	Balancing of a single zone	Commercial balancing at the level of the merged zone, cooperation of participating TSOs	BAL NC update, allowing multi-zone balancing
Physical Balancing	Balance of a single zone	Individual TSOs remain responsible for their network	No adjustment required
Regulatory framework	Individual countries have an individual approach	Harmonised regulatory approach	Updating TAR NC – guidance for harmonised regulatory approach, a calculation at a merged zone level
Contract documentation	Individual for each zone	Necessary Settlement Contracts, Balancing Rules, Reallocation of Balancing Payments	Adaptation of local legislation (harmonization of principles)

Table 25: Summary of gaps of the Trading Zone Merger Scenario (top-down approach)

6.2.5 Impact on stakeholders

6.2.5.1 Gas producers

- Individual impact which would depend on the original capacity contract conditions (original tariff and market destination), because the merged zone creation would abolish intra-zone IP and tariffs and would likely increase the entry/exit tariff to neighbouring zones.
- Creation of one virtual trading point for the whole merged trading zone would increase liquidity in the combined market and put gas producers and suppliers into more intense competition.

6.2.5.2 Midstreamers

- Midstream companies would face lower pancaking effect and lower technical operational risk as they would benefit from simpler gas transmission resulting from a reduced number of zones within the EU.
- One common virtual trading point within the merged zone would also allow for a reduction in the administrative burden multiplied by the number of business points in which the trader is involved.
- We also expect a significant reduction in the financial burden as a result of a common virtual trading point, as it would not be necessary to keep financial collateral for each trading point due to possible netting of deals.

6.2.5.3 TSOs

- TSOs may oppose the change of the regulatory responsibility and establishment of new regulatory rules into the future scheme. This would be the case, particularly if the merging zones originally applied different regulatory approaches. TSOs' revenue composition would be affected by new compensation payments within the merged zone via a TCF. The TCF would on the one hand help attain regulated revenues, but on the other, TSOs would be more exposed to harmonised regulatory principles, which can pose the risk of non-compliance with the original regulatory approach.
- More dynamic capacity calculations would be needed.

6.2.5.4 Hubs

- Hub development would be boosted by the implementation of this proposal; nevertheless, the number of virtual trading points would be reduced.
- Price convergence would also be significantly affected within the merged zones. Full price convergence of the commodity would occur as a result of no transmission tariffs within the merged zone and a common virtual trading point within the embedded balancing zones.

6.2.5.5 Customers

- Customers would profit from lower gas price due to increased price competition in a larger, merged market.
- Due to better conditions supporting a well-functioning market environment such as a larger number of market participants or larger traded volumes, or more market players (demand as well as supply side), greater benefit could also be expected for the end users in the form of lower final prices, balancing costs and an increased security of gas supply (similarly to the Tariff Reform Scenario).
- Transmission cost would be equal for all customers across the merged zone, which could lead to price increases for customers close tomerged zone entry borders; yet, this could be compensated for by cost socialisation or by amending the TCF mechanism rules.
- The increase in the price for final consumers in some of the merged zones would depend on the gas flows and the distance from the point of entry into the zone.
  - In the event of merging the zones on a transmission route where the transmission costs in the second zone include the transmission costs of the first zone, there would be an increase in the tariff in the first and a decrease in the tariff in the second.
  - However, the overall effect for the merged zone is expected to be positive due to an increase in liquidity, price transparency and market size induced by the creation of a common virtual trading point.

6.2.5.6 NRAs

- Regulatory conditions would need to be harmonised in detail with regard to the wholesale market and balancing, which may require an intergovernmental agreement for relevant zones in several countries.
- It would also be necessary to deal with the adjustment of existing LTCs for supply and capacity as discussed above and also in the Tariff Reform Scenario.

6.2.5.7 Neighbouring countries

- The increased market liquidity and market resilience should also have a wider impact on the markets adjacent to such a merged trading zone.

- Transmission tariffs for border entry/exit would likely be higher than before the merged zone creation, because with the abolition of the intra-zone tariffs, additional revenues would need to be recovered at the remaining points (i.e., at the border points and domestic exit points). This would mean less motivation to interact with neighbouring zones within the EU and a widening price divergence among zones.

6.2.5.8 *Summary of impact on stakeholders*

Summary of impact on stakeholders, part 1/2

	Producers	Midstreamers	TSOs	Hubs
Entry/Exit tariffs	Neutral - The new tariff reflects the cost of all marginal entry and exit points. In the case of transit, the effect should be insignificant. If there is one capacity, a larger market is available	Positive - To reduce the effect of tariff chaining (Pancaking), we expect the sum of current tariffs to be higher than the future tariff	Neutral - Revenues are retained	No effect
No commercial tariffs within merger zone	Neutral - The producer does not come from one of the merged zones, so the effect is neutral	Positive - Access to a larger market	Neutral - Revenues are retained	Positive - Greater liquidity within a merged zone
Regulatory frameworks	No effect	No effect	Neutral - There is likely to be a move between TSOs, but the total effect will be zero	No effect
TCF	No effect	No effect	Neutral - Secure existing revenues, but exposed to more regulatory impacts	No effect
Virtual trading point	Positive - Opportunity for new products	Positive - Opportunity for new products	Negative - Requirement for a more efficient system management	Positive - Opportunity for new products
Balancing	No effect	No effect	Negative - Requirement for more optimal system management	No effect
Congestions Contractual/Physical	Positive – No congestion within the merged zone possible, possible increase in congestion to neighbouring zones	Positive – No congestion within the merged zone possible, possible increase in congestion to neighbouring zones	Negative - Requirement for more coordinated system management	No effect
LTC capacity	Neutral - abolished contract and capacities at IPs within the merged zone	Neutral - abolished contract and capacities at IPs within the merged zone	Neutral – revenues for abolished capacity LTCs at IPs within the merged zone to be compensated via TCF	Positive - By eliminating LTC, there will be more liquidity in the market
Investment	No effect	No effect	Positive - This is a common investment, it avoids the risk of sunk costs	No effect
Dispatching	No effect	No effect	Positive - Common dispatching, allowing efficient use of merged zone systems	No effect

Table 26: Impact of Trading Zone Merger Scenario on stakeholders (1/2)

Summary of impact on stakeholders, part 2/2

	Customers	NRAs	Neighbours countries
Entry/Exit tariffs	Neutral - Pancaking behind zones is zero effect	Neutral - Authorities are retained, plus a co-operation agreement	Negative - If a merged zone is created, the tariff will increase at the cross-border point
No commercial tariffs within merger zone	Positive - A more liquid market will lead to overall price reductions	Neutral - Authorities are retained, plus a co-operation agreement	No effect
Regulatory frameworks	No effect	Neutral - Authorities are retained, plus a co-operation agreement	No effect
TCF	No effect	Neutral - Authorities are retained, plus a co-operation agreement	No effect
Virtual trading point	Positive - Possibility of lower prices	Neutral - Need to create a legislative framework, a higher degree of cooperation	Positive - Opportunity for new products
Balancing	No effect	Neutral - Need to create a legislative framework, a higher degree of cooperation	No effect
Congestions Contractual/Physical	No effect	No effect	Negative – capacities to neighbouring zones may be lower
LTC capacity	Positive - Ensuring security of supply	No effect	No effect
Investment	Positive - Ensuring security of supply	Neutral - NRA approves the investment together	No effect
Dispatching	Positive - Ensuring security of supply	No effect	Positive - Easier communication

Table 27: Impact of Trading Zone Merger Scenario on stakeholders (2/2)

6.3 Conditional Market Merger Scenario

This scenario aims to reduce the location spreads between connected neighbouring zones, where one is usually a more developed main market and the remaining is/are less developed connected market(s). By joining them into a conditional merger the zones will be separated by transmission capacities initially priced at zero, and should retain separate balancing zones with one wholesale market price, as long as transmission capacity is available. If the capacity is not available, the markets will be divided by transmission tariff premium and in each zone a different wholesale market price will be formed. In contrast to a trading zone merger, by temporary market separation, this scenario could handle temporary congestions and would not directly *require additional infrastructure investments. Moreover, implementation of this scenario might be more feasible compared to the Trading Zone Merger scenario.*

6.3.1 Introduction and motives for considering this scenario

A Conditional Market Merger Scenario can be applied when a market zone is strongly connected to a larger and more liquid neighbouring zone. In contrast to the previously discussed trading zone merger, the requirement on physical capacity interconnecting the two markets is less strict. The assumption can be made that one of the connected markets is larger, with more diversified supply sources and of greater wholesale market liquidity. As long as the interconnection market capacity is available, the wholesale trading would be mainly performed at the prices of this market. In case of physical congestion, the temporary capacity market premium would enable the wholesale market price disconnection and a local trading market in the less liquid connected market would therefore need to be continuously available. This temporary market disconnection would be the price for lower initial infrastructure investments needed for establishing such arrangement than in the case of the trading zone merger.

Reduced interconnection tariffs between the connected zones in the conditional market merger would impact the TSO revenues. So in order to keep them at the original level and preserve the assumption of TSO neutral impact, the revenues would be collected from the increased tariffs applied at the interconnection points towards the non-participating zones and would be redistributed to the TSO by a local TCF. As mentioned in the previous scenarios, a certain regulatory harmonisation would need to be achieved in order to make the TSO revenues transparent within the conditional market merger.

This measure should create larger, more liquid resilient market area leading to price convergence with the main market with potential to reduce the level of wholesale prices in the connected market. An important fact is that through reduced tariffs between the markets, the flows within the conditionally merged zone would be more efficient and the location spread would be eliminated or reduced as long as interconnection capacity is available. The discussion of the benefits (e.g., larger and more diversified market, greater liquidity, easier and cheaper flexibility import) is similar to the Tariff Reform Scenario, but it is restricted only to several local zones. While both the main and connected markets are expected to benefit from this merger, the connected, less liquid market's benefits are expected to be significantly larger as its prices converge to the traded level in the main market with profit from its liquidity, depth and balancing potential. This scenario could be complementary to the Trading Zone Merger Scenario when each would be applied to suitable mutually and exclusive market combinations to best reflect the interconnection conditions and the respective implementation costs.

The benefits of this scenario are directly linked to efficient available capacity usage. The active application of CMP and tightened limitations on long-term capacity booking are crucial parameters to prevent capacity hoarding. These requirements are similar to the Tariff Reform Scenario, with the difference that alternative capacity booking across neighbouring regions to circumvent the congested direct interconnection of the two conditionally merged zones would be more costly in this scenario, and would not work necessarily as a motivational factor increasing the risks of the capacity hoarding strategy.

In certain respects, this alternative regulatory scenario resembles the electricity market implicit capacity auction model, but there are significant differences:

- There are no implicit auctions; explicit auctions would exist for all capacity tenors.
- Even long-term auction prices could be offered at zero reserve price.
- Capacity would need to be reserved even if delivering for day-ahead or intra-day products.

- Electricity market coupling works only for day-ahead and intra-day products, whereas in this scenario, coupling would work also for forward products as long as there was available capacity

In many respects, this scenario is similar to the Tariff Reform Scenario and Trading Zone Merger Scenario introduced above. Therefore, we present in the key characteristics only the main differences from these two scenarios.

6.3.2 How this scenario addresses market inefficiencies

1.	Transmission tariff levels and structure	Zero cross border tariffs between the main and connected market will lead to wholesale trading mainly performed at the prices of the original market and reduce the location spreads, increasing the common market liquidity. Nevertheless, location spread will remain between connected zones on occasions when not enough transmission capacity is available as needed and interconnection tariffs/congestion fees rise from the initial zero reserve price.
2.	Regulatory and contractual restrictions	This scenario does not address regulatory and contractual issues in a new way and thus the Status Quo from the Reference Scenario remains.
3.	Physical restrictions	This scenario does not address the congestion in a new way and thus the Status Quo from the Reference Scenario remains.
4.	Infrastructure use efficiency	Intra-zonal cross-border tariffs are only applied when the markets are disconnected, thus, market participants will be motivated to behave so as to ensure that markets are not disconnected unless necessary by, e.g., using alternative routes..
5.	EU-level market concentration	Conditional zero intra-zone cross –border tariffs will increase producer to producer supply competition on the merged market..
6.	Local specifics in regulation and limited transparency	Because it will be necessary to set up rules for cooperating TSOs and market operators including NRAs, we consider it appropriate to align the legislative framework of all the affected markets. Such harmonization is in line with the long-term EU objectives.

Table 28: Conditional Market Merger Scenario addressing market inefficiencies

6.3.3 Main amendments to the Reference Scenario

6.3.3.1 Entry-exit zones

We propose to conditionally merge neighbouring zones not suitable for a trading zone merger. The main market should be the more developed gas market with a liquid virtual trading point. The connected market needs to have strong infrastructure connection to the main market in order to enable efficient interconnection flows and only temporary potential capacity restrictions. An example for the conditional market merger could be Austria and Slovenia or Ireland and the UK.

As a result, the conditionally merged zones will have a dominant virtual trading point in the main zone, but a secondary trading point in the connected zone would exist, duplicating the price at the dominant trading point in the main zone. Only in the event of temporary market disconnection, its price would reflect this situation and capacity premium.

6.3.3.2 Tariffs

Tariff structure will be similar to the Trading Zone Merger Scenario. The intra-zone cross-border tariffs will be set to zero, but can be escalated at congestion times by capacity premium. The entry/exit tariffs on the conditionally merged zone borders will be set to compensate the revenue loss from zero intra-zone tariffs and to guarantee TSO revenue neutrality. The TCF mechanism will be established.

6.3.3.3 Economic regulation

Economic regulation will be similar to the Trading Zone Merger Scenario. NRAs within the conditionally merged zone are expected to increase cooperation. The regulatory framework harmonisation should be more influenced by the main market's rules.

6.3.3.4 Capacity LTC

The same approach as for the Tariff Reform Scenario will be applied.

6.3.3.5 Infrastructure

Only neighbouring markets with relatively sufficient interconnection can be connected. New infrastructure investments within the conditional market merger would need to be coordinated because they would directly impact the zonal TCF.

6.3.3.6 Dispatching

As per the Reference Scenario, with closer coordination as in the case of electricity market coupling examples.

6.3.3.7 Legal aspects

The tariff structure and level changes will impact any fixed price capacity LTCs. The impact would be very similar to the Tariff Reform Scenario. This means that the LTC holders could attempt to cancel the outstanding LTC, if it proved advantageous for them and on the other hand, if the expected impact increased the new capacity tariffs covered in their LTC, they would likely keep the LTCs.

6.3.4 Implementation considerations

Compared to the previous scenario, the demands on regulatory environment are less stringent, as cooperation of multiple NRAs should be sufficient for establishment of a conditionally merged zone. Nevertheless, a certain degree of regulatory harmonisation is a necessary condition for smooth operation of a TCF or a similar method for allocation of costs or revenues among the TSOs.

Compared to the Trading Zone Merger Scenario, conditions for connecting and disconnecting the markets need to be agreed upon in this scenario between the TSOs and approved by the NRAs.

Equivalent to the Trading Zone Merger Scenario, legislation relevant to the proposed mergers is the Directive 2009/73/EC (introduction of rules for compensation mechanism, efficient TSO cooperation and introduction of potentially new network code to compensation mechanism), Regulation 715/2009 (update on potential list of merged markets) and amendment of TAR NC (harmonisation of allowed revenue calculation, especially transit and domestic flows related infrastructure).

The Conditional Market Merger can be agreed by both bottom-up and top-down approaches. While in the former, the merger would be induced by individual MSs, the latter would mean an intervention from a supranational institution. As the gap analysis for both approaches are different, we present them separately below.

The gaps for the bottom-up approach are summarized in the following table:

Area	Current situation	Future situation	GAP
Virtual Trading Point	There is at least one business point in the zone	Establish interconnected trading points	Adaptation of local legislation (review of the original trading point setup)
Zero reservation price within conditionally merged zones and setting of new tariffs when the zone is not merged	The tariffs are set by an individual NRA	Tariffs will be calculated together via the conditionally merged zones	Adaptation of local legislation (formal cancellation of internal points for reservation, common procedure for calculating tariffs)
Regulatory framework	Individual countries have an individual approach	Uniform approach	Adaptation of local legislation (harmonisation of regulation)
Contract documentation	None	Necessary Settlement Contracts, Reallocation of Congestion Payments	Adaptation of local legislation (harmonisation of regulation)

Table 29: Summary of gaps of the Conditional Market Merger Scenario (bottom-up approach)

The gaps for the top-down approach are summarized in the following table:

Area	Current situation	Future situation	GAP
Create conditionally merged zones	Not addressed	Probably ENTSOG (ACER/EC) will issue recommendations which zones are appropriate to merge, NRAs will conduct economic tests	Updating Regulation 715/2009 - imposes an obligation to regularly compile a potential list of merged zones
Zero reservation price within conditionally merged zones and setting of new tariffs when the zone is not merged	The tariffs are set by an individual NRA	Tariffs will be calculated together via the conditionally merged zones	TAR NC update allowing an exception for cross-border bodies within the conditionally merged zone

Area	Current situation	Future situation	GAP
Regulatory framework	Individual countries have an individual approach	Uniform approach	Updating Regulation 715/2009 - Requires a unified (not only harmonised) approach, a calculation at a merged zone level
Contract documentation	None	Necessary Settlement Contracts, Reallocation of Congestion Payments	Update of Directive 2009/73 - The condition of merger is the creation of contractual documentation between zones

Table 30: Summary of gaps of the Conditional Market Merger Scenario (top-down approach)

6.3.5 Impact on stakeholders

6.3.5.1 Gas producers

- Potentially positive or neutral impact, depending on whether the producer already has capacity booked to one of the future conditionally merged zones, as the merged trading zone would enable greater access to additional market(s).
- Creation of a common, though conditional virtual trading point for the whole merged trading zone would increase liquidity in the connected market and put gas producers and suppliers into more intense competition.

6.3.5.2 Midstreamers

- Midstream companies would face lower pancaking effect and lower technical operational risk as there would be fewer counterparties at the time of the merger.
- One common virtual trading point would also allow for a reduction in the administrative burden multiplied by the number of business points in which the trader is involved.
- We also expect a significant reduction in the financial burden as a result of a common virtual trading point, as it would not be necessary to keep financial collateral for each trading point due to possible netting of deals.

6.3.5.3 TSOs

- TSOs' revenue composition would be affected by new compensation payments within the conditionally merged zone.
- In the case of zones disconnection, the entry/exit transmission tariffs must be set within conditionally merged zone as capacity premium.
- More dynamic capacity calculations would be needed.

6.3.5.4 Hubs

- The benefit for the main market will be an additional increase of liquidity and size of the market as the price arbitrage between the main zone and the connected zone would attract additional volumes to be traded in the main market.

6.3.5.5 Customers

- The benefit for the connected less liquid market will be easier access to the main, more liquid market, higher supplier competition, which in particular means a reduction of the wholesale gas price and thus lower prices for end consumers.

- Reduction of the tariffs within the conditionally merged zone will result in higher entry and exit tariffs towards other zones in order to keep the TSO revenue neutrality. Hence, the import and export of gas from other zones will very likely be more costly.

6.3.5.6 NRAs

- The legislative and regulatory gas market harmonisation between the merged markets would be necessary for: (i) the wholesale market, (ii) capacity treatment and (iii) TCF establishment and operation.
- If there was an agreement between several market zones and technically suitable conditions of strong interconnection, the conditional market merger could be simpler to agree on compared to the other scenarios such as the Trading Zone Merger Scenario.

6.3.5.7 Neighbouring countries

- The increased market liquidity and market resilience should also have a wider impact on the neighbouring markets to such a conditionally merged trading zone.
- Transmission tariffs for border entry/exit would likely be higher than before the zone creation, because with the zero reservation price within the conditionally merged zone, additional revenues would need to be recovered at the remaining points (i.e., at the border points and domestic exit points). However due the lower number of zones involved in conditional market merger, we expect a relatively lower impact on cross-border tariffs between neighbouring zones and conditionally merged zones.

6.3.5.8 Summary of impact on stakeholders

Summary of impact on stakeholders, part 1/2

	Producers	Midstreamers	TSOs	Hubs
Entry/Exit tariffs	Neutral - The new tariff reflects the cost of all border entry and exit points, varying impact based on exact capacities held	Positive - Reduce the effect of tariff pancaking. We expect that the sum of current individual tariffs is higher than the future common tariff.	Neutral - Revenues are retained	No effect
Zero reservation price within conditionally merged zone	Neutral - The producer does not come from one of the conditionally merged zones, so the effect is neutral	Positive - Access to a larger market	Neutral - Revenues are retained via TCF	Positive - Greater liquidity within a conditionally merged zone
Auction premium at the time of disconnection	Negative - The need to participate in the auction	Negative - The need to participate in the auction	Negative - more complex operation activity	Negative - A temporary reduction in liquidity
Regulatory frameworks	No effect	No effect	Neutral – Likely revenue reallocation between TSOs, but the effect will be zero	No effect
TCF	No effect	No effect	Neutral - The basis is to secure existing revenues	No effect

	Producers	Midstreamers	TSOs	Hubs
Virtual trading point	Positive - Access to a larger market	Positive - Access to a larger market	Neutral - Dynamic capacity allocation tools will be applied	No effect
Congestions Contractual/Physical	Negative - Risk of congestion at a time of increased demand from an attached market	Negative - Risk of congestion at a time of increased demand from an attached market	Negative - Requirement for more optimal system management	No effect
LTC capacity	Negative – No LTC booking possible for new contracts and preferably also none for old ones	Negative – No LTC booking possible for new contracts and preferably also none for old ones	Negative - less revenue assurance in long term	Positive - Higher liquidity

Table 31: Impact of Conditional Market Merger Scenario on stakeholders (1/2)

Summary of impact on stakeholders, part 2/2

	Customers	NRAs	Neighbours countries
Entry/Exit tariffs	Neutral - Pancaking behind zones is zero effect	Neutral – Need to secure agreement on regulation	Negative - If a merged zone is created, the tariff will increase at the cross-border point
Zero reservation price within conditionally merged zone	Positive – Reduction of pancaking effect within the conditionally merged zone	Neutral - Need to secure agreement on regulation	Negative – potential higher exit fees from the conditionally merged zone to the third countries
Auction premium at the time of disconnection	No effect	No effect	No effect
Regulatory frameworks	No effect	Neutral - Authorities are retained, plus a co-operation agreement	No effect
TCF	No effect	Neutral - Authorities are retained, plus a co-operation agreement	No effect
Virtual trading point	Positive - Possibility of lower prices	Neutral - Need to create a legislative framework, a higher degree of cooperation	Positive - Opportunity for new products
Congestions Contractual/Physical	No effect	No effect	No effect

	Customers	NRAs	Neighbours countries
LTC capacity	Positive - Ensuring security of supply	No effect	No effect

Table 32: Impact of Conditional Market Merger Scenario on stakeholders (2/2)

6.4 Combined Capacity-Commodity Release Scenario

This scenario aims at addressing the inefficiencies in gas wholesale market operation stemming from the existence of long term (longer than annual) transmission capacity bookings on the existing European grid. These inefficiencies are contractual congestion and downstream market foreclosure. In Chapter 4 we analysed in detail the significance of these risks and the efficiency of existing regulatory measures to address them.

Regarding contractual congestion, we concluded that a more efficient deployment of the existing CMP GL mechanisms, together with the likely phase-out of the problem due to expiring legacy LTCs and reduced amount of forward LT capacity bookings by EU midstreamers, sufficiently addresses this risk.

However, we also concluded that CAM NC in its present form is unable to effectively address the risk of market foreclosure posed by long-term capacity bookings, at present primarily favoured by extra-EU gas producers and their affiliates. These market participants are willing to conclude long-term transmission capacity contracts within the EU on the existing or new infrastructure of up to 10 to 15 years. Further, we have concluded that even if LT capacity contracts on the intra-EU infrastructure were to a high degree turned into short term bookings (annual or shorter), restricted competition at some highly concentrated local markets could prevail due to the lock-up of gas upstream resources in LT commodity contracts.

To address these issues, we propose in this alternative scenario to significantly reduce the possibility of LT capacity bookings within the EU on the existing as well as on new infrastructure. Reduced LT capacity bookings could be induced by increasing the share of technical capacity TSOs are obliged to set aside and offer for auction for yearly or shorter durations both for existing and new capacities. For future contracts on existing and new capacities this obligation can be introduced immediately. For existing LT capacity contracts this requirement would be imposed from a predetermined future date (sunset clause).

To complement the opening of the capacity market, we also propose obliging gas producers/importers to sell at least 50% of the imported gas at the nearest VTP to their entry into the transmission grid on EU territory. This would take the form of sales to liquid hubs in liquid markets and gas release programmes in those EU entry markets experiencing limited gas liquidity and possible market foreclosure.

The gas release programmes would be implemented by the supervision of NRAs under the described EU framework.

The scenario proposes a simultaneous increase up to 50% in the share of short term transmission capacities for both existing and new infrastructure (50-50) and an obligation for gas producers/importers to sell at least 50% of their gas at the nearest VTP to their entry into the transmission grid on EU territory (50).

6.4.1 Introduction and motives for considering this scenario

Long-term capacity bookings are traditionally needed to ensure financing for new, large scale infrastructure investments and provide revenue certainty for TSOs. In addition, LT commodity contract holder suppliers require containment of the risk arising from access and costs of transmission services.

We accept both arguments as valid for new transmission investments. CAM NC on incremental capacity sufficiently addresses the issue of LT bookings in the context of new investments.[151]

However, for existing infrastructure, the traditional arguments in favour of LT capacity booking seem not to hold.

- Financing for the capital expenditures of existing infrastructure is granted by existing LT bookings and related payments. Thus, long term booking of available transmission capacity is not a precondition for TSO investment financing. Investment financing related to maintenance and marginal upgrades is ensured by regulatory arrangements.
- TSO's exposure to revenue volatility is rather limited. Demand for transmission services is driven by aggregate annual consumption that is rather stable in the medium run. Long-term bookings would be replaced by short-term bookings where the transmission service was required thus bringing the actual use of the system closer to actual customer needs. In addition, TAR NC provides a compensation mechanism for revenue shortfalls. The risk of revenue shortfalls is also limited by the fact that short-term capacities are priced higher to keep at least booking cost equivalence between a flat yearly booking and profiled monthly booking.
- If sufficient transmission capacity exists, the risk exposure of a LTC supplier to capacity booking risk and price risk could be further limited by hedging contracts. The LTC supplier could engage instead of the long-term capacity contracts in hedging instruments which would offset potential losses arising from volatility of the transmission fee in the case of potential shortage of capacity at IPs.[152]

Moreover, existing infrastructure forward long-term capacity bookings seem to contradict with the target model of a fully liberalized and integrated internal gas market, where short-term product market optimization through inter-regional arbitrage plays a key role in providing efficient market outcomes in volume allocation and price determination. Under liberalized market conditions gas flows should follow price signals instead of pre-defined contracted routes. If pipeline capacity allocation was to support efficient market operation, it should be as closely related to actual gas flows as possible. Emerging, often volatile price signals with significant location spreads, will influence gas flows continuously within the EU. The result is that continuously changing flows leave the sunk cost of unused LT booked capacity with the shareholders of LT booking market participants.

In the worst case, long-term capacity bookings create inefficiency in the use of existing infrastructure in the form of contractual congestion (see Section 4.2.5) and contain the risk of downstream market foreclosure (see Section 4.2.6).

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[151] Chapter V of Regulation 2017/459.

[152] Similar instruments (financial transmission rights) have already been developed in electricity markets, and more widespread use is foreseen after full implementation of the CACM network code.

We argue that the gradual dismantling of LT capacity bookings on existing infrastructure due to the expiry of existing contracts creates an opportunity in this regard for the future EU gas market.

- The system of incremental capacity allocation, according to CAM NC, ensures financing for required new infrastructure. In the meantime, for existing infrastructure, decreasing long term bookings could decrease contractual congestion and the related risk of capacity hoarding, thus improving the efficiency of the use of the existing transmission network.
- If long-term bookings are replaced by short-term bookings, depreciated assets with very low or no utilisation could be gradually decommissioned[153] or, if kept for security of supply or strategic reasons, paid by the customers of those market zones enjoying these benefits. The revenue certainty of the TSO to recover their justified costs will be ensured by the national regulators.

However, our analysis in Section 4.2.6 concluded that it could be a rational strategy for extra-EU producers with significant market power, occasionally in tandem with their local incumbent supplier partners, to continue with long-term capacity bookings on intra-EU IPs, thus strengthening their market position downstream. This can create problems regarding the contestability of certain local markets and contribute to high local wholesale market concentration (see discussion in Section 3.1). We provided examples in Section 4.2.6 of how, through delivery point choices, producers can strengthen their downstream market position. The March 2017 Prisma auction (see Section 3.8.3.1) also provided a recent indication and evidence on long-term booking related market foreclosure risk. This first EU-wide implementation of the CAM NC led to the conclusion of a significant amount of new long-term capacity bookings on existing West-East reverse flow capacities that, if implemented, will likely increase the exposure of CEE Member States to their dominant supplier from 2020.

This regulatory proposal consists of a combination of measures to address long-term capacity booking related inefficiencies and market foreclosure risks.

6.4.2 How this scenario addresses market inefficiencies

1.	Transmission tariff levels and structure	Because part of LTC gas will not have to be shipped from higher-priced to lower-priced zones and then back, while unnecessarily locking up of sometimes critical transmission capacities, part of the infrastructure will be opened up from contractual congestion. The flows will primarily follow wholesale spreads.
2.	Regulatory and contractual restrictions	While some IPs may be contractually and physically congested, this proposal would open up different routes or interruptible products with low probability of interruption to circumvent them. The change in CAM NC will promote the use of short-term capacity products instead of long-term products. In CMP an increased use of over-subscription and buy-back mechanism becomes possible.
3.	Physical restrictions	The implementation of the scenario could help to identify physically-congested pipelines or areas from an EU perspective. If one pipeline is fully booked there may be another physical route opened up for

[153] New long-term capacity bookings are also unlikely for those assets.

		shippers to deliver gas to the desired destination market.
4.	Infrastructure use efficiency	Improved efficiency in using the existing EU gas transmission network as location spreads decrease and contractual capacity use restrictions are reduced.
5.	EU-level market concentration	Delivery and gas release programmes are designed to reduce market concentration, especially in markets with lower liquidity and higher concentration levels.
6.	Local specifics in regulation and limited transparency	The proposed EC/ACER framework rule for obligatory gas release programmes could prevent distortions from differences in local gas release programme designs.

Table 33: Combined Capacity-Commodity Release Scenario addressing market inefficiencies

6.4.3 Scenario measures and design components

We propose to implement a combination of the following regulatory changes:

A. Increasing the share of technical capacity TSOs are obliged to set aside and offer for auction for yearly or shorter durations both for existing and new capacities. For future contracts on existing and new capacities this obligation can be introduced immediately. For existing LT capacity contracts this requirement would be imposed from a pre-set future date (sunset clause).
B. Obliging gas producers/importers to sell at least 50% of the imported gas at the nearest VTP to their entry into the transmission grid on EU territory. This would take the form of sales to liquid hubs in liquid markets and gas release programmes in those EU entry markets experiencing limited gas liquidity and possible market foreclosure. The gas release programmes would be implemented by the supervision of NRAs under framework rules developed by EC/ACER. The current legislation allows for the introduction of the gas release program as one of the measures. The change we propose requires an adjustment of the current legislative framework (TEP) in the sense that the implementation of the gas release program is coordinated, common and according to identical rules in any Member State. This requires coordination to ensure a common approach.

What follows is a discussion on the major regulatory points of this alternative scenario and related risk and gap analyses.

A. Increasing the share of technical capacity TSOs are obliged to set aside and offer for auction for yearly or shorter durations both for existing and new capacities.

According to paragraphs 6 and 7 of Article 8 of Regulation 2017/459, the share of existing technical capacity TSOs are obliged to set aside and offer for auction for yearly or shorter durations is 20% today. This share could simply be increased from 20% to any level between 50 and 100%, depending on further analysis. The same approach of increasing the share of yearly or shorter durations from 10% to 50% should also be considered for the incremental capacity within the EU in order to prevent future market foreclosure.

Such an amendment of CAM NC could most probably eliminate the risk of forward LT capacity booking-related downstream market foreclosure fully (in the area of 80-90%) or largely (close to 50%).

This measure would be non-discriminative so that not only extra-EU gas producers but also EU producers and midstreamer companies would be further limited in their ability to book cross-border capacity for longer than one year. An obligation closer to 50% could preserve the opportunity of stakeholders to extract the benefits from multi-year bookings without the risk of foreclosing alternative shippers from using the grid.

On the other hand, the obligation closer to 100% would create transportation cost-related risks for long-term commodity contracts. Instruments like financial transmission rights, introduced by TSOs, could hedge this price risk of changing yearly capacity price though. In addition to strong reduction of the risk of downstream market foreclosure, this solution could open the opportunity to design implicit capacity auctions for intra-EU cross-border capacities as legacy contracts expire.

For existing LT capacity contracts, these stricter capacity reservation rules should be implemented from a predetermined future date (sunset clause) so that market participants have sufficient time to adjust to them.

For potential legal implications of adjustments to existing contracts please refer to the Tariff Reform Scenario.

B. *Obligation for gas producers/importers to sell at least 50% of the imported gas at the nearest VTP to their entry into the transmission grid on EU territory*

As discussed above, at present it is the gas producers or importers who might be the most likely motivated to book cross-border capacity long-term on the existing transmission grid within the EU. The connection of holding commodity supply together with long-term capacity booking raises the associated risk of market foreclosure, because even if short-term capacity is available, unless there is also competitively-priced commodity available, alternative suppliers are not be able to compete.

While historically, gas upstream development projects would be initiated only after a long-term gas purchase and sale agreement was concluded, today, gas producers can sell their gas at liquid market places wherever they exist. Thus, producers can sell their gas at the nearest gas hub and do not need to find a market or end customer first. This change in market structure largely removes the simultaneous need for long-term capacity products when supplying commodity.

However, liquid hubs and competitive markets are not present at each trading zone next to EU entry points. The ACER market monitoring reports show that several of the countries on the gas supply routes experience low market liquidity and show high wholesale gas supply concentration. As mentioned earlier in this report, the location spreads for those markets are often not below NCG or TTF as it would be expected on the supply routes. The prices are rather determined by the sum of the transportation costs from the liquid locations (NCG or TTF) as the alternative opportunity price, hence priced above the NCG or TTF. In these cases, the development of local gas market liquidity should be actively encouraged.

In this alternative scenario we propose to give the EC/ACER the authority to create a framework rule for gas release programmes in EU entry markets with low liquidity and high market concentration (possible market foreclosure). Auctions, supervised by NRAs and organized by the producers/importers who supply the market or just transport their gas volumes through this market would add additional wholesale liquidity and make sure that interested gas suppliers would be able to procure their gas in a competitive fashion. Due to the simultaneous opening up of the capacity market, long-term capacity booking in connection with commodity supply contract of an incumbent market player would no more be a strict constraint for competing market players. Auctions then could become a source for alternative gas supplies to the neighbouring zones of low market liquidity and currently booked-out transmission capacities.

Under the EC/ACER framework rule, gas producers/importers would be obliged to sell at least 50% of their gas at the nearest VTP to their entry into the transmission grid on EU territory. The exact extent of the release proportion in percentage terms of an outstanding import volume would be at the discretion of the ACER and would reflect the extent of the foreclosure problem, the size of the market/region and the volume of gas imports.

The proposed gas release programme would target gas producers and importers importing from outside of the EU only, because:

- EU gas production contracts are limited in size, mostly destined for own market zone and decreasing in importance with decreasing production[154]
- Other intra-EU imports would either result from the previous indent, or EU imports from other directions, which would already underlie the same scrutiny on market foreclosure at its EU entry point into the EU, also with reference to the neighbouring or regional markets, and hence would be treated fairly.

In the case of the gas release framework rule it would be crucial to correctly specify the auction requirements, next to the targeted auction volume (most suitably as a share of the imported volumes), the type of products and schedule of the auction. Because the auctions should enable alternative gas sourcing, they should be composed of several products (at least yearly, monthly and daily), organised repetitively and under a known schedule, so that market participants can correctly set their sourcing strategies in advance.

The implementation of this regulatory proposal would clearly limit the contractual freedom of gas producers to some extent, most notably at the point of delivery for their product. However, such an obligation could boost the development and liquidity of existing gas hubs, thus contributing to the further development of the EU gas wholesale market.

The potential introduction of authority to require gas release by EC/ACER could be based on the case of the current wording of the Third Energy Package directives, which stipulate that Member States shall ensure that NRAs are granted the powers in an efficient and expeditious manner. For this purpose, the NRA shall have at least the power to carry out investigations into the functioning of the energy markets, and to decide upon and impose any necessary and proportionate measures to promote effective competition and ensure the proper functioning of the market. Where appropriate, the NRA shall also have the power to cooperate with the national competition authority and the financial market regulators or the EC in conducting an investigation relating to competition law (art. 37/4 b) Directive 2009/72/EC, art. 41/4 b) Directive 2009/73/EC). This has been transposed appropriately into the MS´s national law (for example art. 18a or 61a of Czech Energy Act No. 458/2000 Coll.). It is implicitly included that the establishment of gas-release programmes is one of the possible measures that can be used to promote effective competition and ensure the proper functioning of the market.

A gas release programme has been and continues to be implemented in several European countries. A gas release programme is either part of a broader action plan required under national law and/or designed by the national energy regulators to open the gas wholesale markets to competition (Poland, UK, Spain, Italy) or is implemented as undertakings in merger or antitrust procedures (France, Germany, Austria, Hungary, Greece).

[154] In 2016 The Netherlands reported by far the largest EU net gas export being below 150 TWh in net gas exeports.

Currently EU law recognises the institute of gas-release measure and stipulates that the power to impose such a measure has been granted to each MS. However, it should be possible to move this responsibility up by one level to the European level, to enable that such a measure or action could be taken in cooperation of several NRAs, if found that the market functioning is currently restricted on the European level and when this process is stipulated by the EU law in a clear, transparent, non-discriminatory manner. Moreover, such an approach should be more than welcome to promote the further integration of the IGM.

Note that the simultaneous implementation of the Tariff Reform Scenario and the Combined Capacity-Commodity Release Scenario could make the use of existing gas infrastructure seamless and very competitive and potentially reduce necessary investments into additional new infrastructure compared with the Reference Scenario.

6.4.4 Main amendments to the Reference Scenario

6.4.4.1 Entry-exit zones

As per Reference Scenario.

Nevertheless, this scenario is not conditional on specific zone design and could be well applied even under different zone settings, potentially also in combination with the other discussed alternative scenarios.

6.4.4.2 Regulatory action

It would be necessary to increase the requirement of technical capacity, which TSOs are obliged to set aside and offer in auction of yearly or shorter durations in the case of the existing infrastructure to 50 – 100% and in the case of new incremental capacity to at least 50%. These minimum capacity auction limits are currently set to 20% and 10% by paragraphs 6, 7 and 8 of Article 8 of CAM NC (EC Regulation 2017/459).

The gas release obligation under the new EC/ACER framework rule would need to be implemented into the EU legislation. Currently the NRAs have the option given under the Directive 2009/73/EC and under the above-mentioned conditions to resort, based on its consideration, to a gas release programme. Under this alternative scenario, EC/ACER would be entitled to develop a framework rule under which NRA could initiate and supervise gas release programmes for all gas importing entities from outside of the EU.

6.4.4.3 Outside suppliers

Suppliers from third countries would be able to achieve the same level of gas sales to the EU as in the Reference Scenario, without the need to ensure long-term transportation capacities within the EU to their final customers. Their ability to conclude and also keep existing capacity long-term contracts on gas transmission within the EU would be limited to comply with the newly-proposed increased minimum capacity volumes reserved for short-term reservations.

Further, their ability to target gas supplies for individual market zones could, to a certain degree, be restricted when the EC/ACER rule prescribed enacting gas release programmes. When a gas release programme is implemented, the importer would lose its control over choosing its partner taking over part of its gas volume. If the importer is not be able to have control over the some released gas after the auction, it may additionally need to buy such a volume in the market or import extra volumes to supply its original customer in full volume.

As a result, the role of transportation cost could change, so that the long-term supply would be less likely to target establishing the final destination market price, based on the distance to the nearest liquid hub, but would also have to take into account the actual gas flow, especially in the case of large transiting volumes, when a gas release programme is established upon the EU gas entry. Additionally, if long-term commodity supplies were exposed to a larger proportion of short-term capacity reservations, the transmission cost would be more likely to change. Nevertheless, the final risk distribution between the foreign producer/importer and gas receiving party would depend on negotiating power, which is impossible to quantify.

We expect that the impact on gas producers/importers would be different based on the historical individual supply strategy. The least impact would be expected on the producers/importers supplying liquid market areas right at the EU border with supplies linked to local market prices. On the other end of the spectrum, producers/importers supplying distant market areas with low level of competition, at prices not based on local liquid market pricing would be exposed to the obligation of a larger amount of short-term capacity bookings and to a higher risk of gas release programme at the EU entry and its larger price impact.

6.4.4.4 Traders, shippers

EU traders will also be exposed to more short-term capacity based transmission reservations and would need to adjust their booking behaviour, though for many of them, it would already be the rule by the time of considered scenario implementation as indicated by earlier evidence on currently experienced capacity booking behaviours. They would also be able to participate in any gas release programmes, which would have a potentially high impact on the operations of presently less liquid virtual trading points.

So, we expect both wholesale traders and retail suppliers to benefit from increased market liquidity, access to capacity and to gas released in the auctions. We expect that increased competition, ceteris paribus, would exercise a downward pressure on the wholesale market prices in the potentially foreclosed markets.

The EU based companies importing gas from non-EU countries would be in the same position as external producers/importers and would have to comply with the new rules.

6.4.4.5 TSOs

Financial certainty from long-term capacity bookings might decrease initially for TSOs as long-term tariffs and reservations would be increasingly substituted by short-term bookings at potentially variable short-term tariffs. With reduced long-term bookings, the actual bookings would likely more reflect the actual flows and the reported capacity overbookings known from the past would not be likely to occur. However, NRAs are the key players to ensure the financial stability of TSOs and its revenues. Related regulatory action might involve the revision of transmission tariff structures and/or the justified cost basis of TSOs.

6.4.4.6 Local incumbent wholesalers

The resulting more rational and flexible capacity bookings will open increased cross-border trading opportunities and put stronger pressure on local incumbent wholesalers. This might lead to reduced market concentration. Local incumbents will have the chance to manage their volume risk close to the EU entry points. Nevertheless, tariff impacts and local market spreads should still exist.

Further, in comparison to the producers, we expect several midstreamers to be competing for the transmission capacity from the EU-border to the individual countries and their customers, therefore improving the level of competition especially in the targeted potentially foreclosed regions and market zones, and hence also generally within the EU.

6.4.4.7 Customers

Customers are expected to be the apparent potential winners especially in those market zones with currently high local wholesale market concentration and related higher wholesale prices.

6.4.4.8 NRAs

National regulators will have to mitigate the impact of this scenario on TSO revenues. They will also be responsible for administering gas release programmes under the EC/ACER framework. NRAs will play the role of coordinators at the local level. Therefore their competence will include setting the auction dates, determining the volume to be offered in auctions, agreeing what entity(ies) will be on the bid side, setting the price mechanism, etc. Individual NRAs must be coordinated at the EU level by the EC/ACER to allow for coordinated action within the Member States.

The obligatory gas release programmes would be also a good opportunity fro the NRAs to encourage the strenghening of local exchanges, especially in the currently less liquid markets, bacause the exchanges could strive for the potential administering of gas release programmes. Such gas auctions by the producers/importers in the EU gas entry market zones with high wholesale market concentration should ensure increased liquidity.

6.4.4.9 Legal aspects

For this regulatory scenario to be meaningful, the switch to short-term capacity reservations within the EU would need to apply to all existing supply contracts. This would be a legal challenge, because existing bilateral commodity and capacity LTCs would need to be amended. The contract holders preferring the current contract form to the proposed new structure would be unlikely to voluntarily accept the change.

If this regulatory scenario applied to new contracts, its impact would be very limited, because it would take a long time before all the long LTCs expired and were compliant with the scenario.

6.4.5 Implementation considerations

This scenario introduces relatively few changes to the current situation, but these changes are substantial. The first proposed change is increasing the share existing technical capacity TSOs have for short-term booking and the second change is the realization of a sales obligation/gas release programmes.

In the current version of the CAM NC, transmission capacities for short-term contracts (annual and shorter period) are mandatory for at least 20% of existing technical capacity (Article 8). In this scenario, we suggest increasing this proportion to at least 50%. Similarly, it is proposed to limit the incremental capacity from its current 10% for short-term booking to a minimum of 50%. These measures require a modification of the CAM NC in Article 8.

The second measure, namely the obligation for gas producers/importers to sell at least 50% of the imported gas at the nearest VTP to their entry into the transmission grid on

EU territory, and as part of this obligation the implementation of gas release programmes, would require a more extensive legal / regulatory adjustment. It could be done by adjusting the Regulation 715/2009 or a new regulation could be prepared, which would fully cover this issue. It is necessary to specify under which conditions part of the volume must be released. This program must be valid for all entities holding commodity LTC as it is likely to be relevant to non-EU entities.

The gaps are summarised in the following table:

Area	Current situation	Future situation	GAP
Technical capacity reserved for short-term auctions	20%	Newly set to 50 - 100%	Modification of points 6 and 7 in Article 8 CAM NC
Adjustment of existing LTCs (commodity and capacities)	None	Restrictions only in connection with the new infrastructure, others cancelled	Editing Regulation 715/2009
Capacity reservation limits	Annual capacity offer for 5-15 years (existing, new infrastructure)	Limit annual auction only to the following year	Modification of point 3 in Article 11 of the CAM NC
Gas release programme	Applies e.g., in Italy, Poland, UK, Spain	The obligation to offer gas in the first EU country (except for end-user deliveries or delivery points within the EU)	Update Regulation 715/2009 - imposes an obligation to offer gas on market terms (trading platform)

Table 34: Summary of gaps of the Combined Capacity-Commodity Release Scenario

6.4.6 Impact on stakeholders

6.4.6.1 Gas producers

- For producers/importers, this alternative scenario would likely mean weakening their market position vis-à-vis their counterparty and increasing competition among alternative gas sources within the EU. This is because transmission routes will be more exposed to short-term reservations and together with potential gas release programmes would increase the likelihood of alternative competitive gas supplies increasing competition in regions and zones with previously high wholesale market concentration and low liquidity.
- Given that long-term contracts are expected to originate from non-EU sources, this scenario will especially impact importers of non-EU gas. The largest impact would be on long-term contracts delivering into non-liquid zones experiencing potential foreclosure, as both the capacity would be switched to short-term tenors and gas release could be initiated with a likely impact on pricing. On the contrary, if the delivery is to a market zone at an entry point to the EU with local liquid market at traded market conditions, such deliveries would be least impacted, as they trade in the local market, are not exposed to additional (long-term) intra-EU capacity bookings and would be priced at traded market anyway, so not exposed to gas release price risk.

6.4.6.2 Midstreamers

- If the midstreamer is a LTC importer, the perception of the change is likely to be negative as described above in the case for producers. Other midstreamers (which are not LTC holders) are expected to perceive the proposed changes positively, in particular because of the release of transmission capacities and because of the increase in liquidity in markets where the gas release programme will be applied. They would be given the opportunity to book and use alternative supply routes to compete with original local incumbents.

6.4.6.3 TSOs

- This scenario would create two risks to the TSOs, the risk of revenue exposure to short-term bookings and hence potentially lower certainty, and the increased risk of incremental capacity investments, which might generate greater uncertainty in the investment area. Nevertheless, both of the risks can be addressed by the NRAs when determining regulated revenues (including tariff setting) and when assessing the necessity of new investments and their return.

6.4.6.4 Hubs

- This scenario design is designed to support market liquidity which will likely be realised in the OTC market as well as in increased trading platform volumes, so it provides a positive impact for the trading hubs.

6.4.6.5 Customers

- Due to the increased competition and increase in market liquidity as a result of the proposed regulatory measures, we expect, ceteris paribus, a decrease of wholesale prices also positively influencing end consumer prices. Moreover, the scenario implementation should also have a positive impact on security of supply, as this scenario will increase source-to-source gas competition and could also partially decrease one source dependence in the case of new supplies via previously hoarded capacities (see the analysis of single zone dependence on supplies from one supplier).

6.4.6.6 NRAs

- We do not expect any significant impact on the NRAs. They could only be instructed by the EC/ACER to initiate and manage a gas release programme and set its conditions in addition to the current tasks.

6.4.6.7 Neighbouring countries

- Due to a greater share of available cross-border technical capacity which would be released from capacity LTC, we expect a positive impact on wholesale prices with better convergence between neighbouring countries. Due to higher liquidity and persistence of advanced areas, we expect, ceteris paribus, the downward price convergence to prevail.

6.4.6.8 Summary of impact on stakeholders

Summary of impact on stakeholders, part 1/2

	Producers	Midstreamers	TSOs	Hubs
Reduction of LTC share of capacity	Negative - Some producers have supply points within the EU, thus limiting their space	Positive - Greater capacity should be available	Neutral - The revenues are retained but less predictable	Positive - Greater share of traders

	Producers	Midstreamers	TSOs	Hubs
Gas release programme	Negative - Disallowing potential benefits from bilateral contracts	Positive - Greater volume of gas should be available	Neutral - Revenues are retained, but tariffs must be recalculated	Positive - Greater share of traders
Limitation of contract lengths	Negative - Disallowing potential benefits from bilateral contracts	Negative - Risk of changing the capacity price	Neutral - Revenues are retained, but tariffs must be recalculated	Positive - Greater share of traders
Congestion Contractual/Physical	Positive - Thanks to the reduced congestion capacity	Positive - Thanks to the reduced congestion capacity	Positive - Limiting contractual congestion will lead to better use of network	No effect
Change the method of trading	Negative - Disallowing potential benefits from bilateral contracts	Positive - Greater share of traders in the single market	No effect	Positive - Higher liquidity

Table 35: Impact of Combined Capacity-Commodity Release Scenario on stakeholders (1/2)

Summary of impact on stakeholders, part 2/2

	Customers	NRAs	Neighbours countries
Reduction of LTC share of capacity	Positive - A more liquid market will lead to overall price reductions and ensure security of supply	No effect	No effect
Gas release programme	Positive - A more liquid market will lead to overall price reductions and ensure security of supply	No effect	No effect
Limitation of contract lengths	Positive - A more liquid market will lead to overall price reductions and ensure security of supply	No effect	No effect
Congestion Contractual/Physical	No effect	No effect	No effect
Change the method of trading	Positive - A more liquid market will lead to overall price reductions and ensure security of supply	Neutral - Only the calculations change, basically nothing changes	No effect

Table 36: Impact of Combined Capacity-Commodity Release Scenario on stakeholders (2/2)

6.5 Extra-EU upstream – EU downstream strategic partnership concept

This concept aims to address the inefficiencies in EU gas wholesale market operation stemming from high market concentration in supplying its growing import needs. As we pointed out in Section3.2, the EU is developing its competitive internal gas market *without the hope of having a truly competitive upstream sector. Since domestic gas production is forecasted to decrease and the future of non-conventional gas production seems to fade away, the EU has to rely on Extra-EU gas suppliers in the long term.*

EU industrial customers have been paying a significant wholesale gas price premium over their US competitors in the last decade, largely due to the concentrated nature of the EU gas upstream sector and the related producer rents. By the end of 2016, EU gas wholesale prices were still two times that of the Henry Hub. This competitive disadvantage threatens the future of gas intensive industries in the EU and creates comparative welfare losses for EU retail gas customers.

At the same time and under these upstream circumstances, gas market related EU policy and regulation have promoted competition and related lower prices by creating standardized market rules and by supporting infrastructure investments to enhance import diversification via LNG as well as pipeline. Due to obvious political reasons, much less EU effort has been devoted to develop and implement mutually beneficial energy sector reform related cooperations with its major pipeline suppliers.[155] In particular, the cooperation with Russia almost halted after 2014.

Unlike the former alternative regulatory scenarios (Sections 6.1 - 6.4) that focused exclusively on EU welfare improving measures, the Extra-EU upstream – EU downstream Strategic Partnership Concept is a cooperative concept aiming at adressing our hypothesis of the EU-upstream concentration issue. In this concept, we are showing an example of how the combined welfare of the EU and its major pipeline suppliers might be significantly improved. For demonstrative purposes, we have developed this concept including only Russia at this stage, the most important gas producer for EU, but if such a concept would be considered, all producers could participate.

6.5.1 Concept measures

We propose to investigate the welfare implications of the combination of the following regulatory changes.

- The EU and Russia enters into a mutually beneficial agreement to integrate their gas markets in a fundamental way.
- This market integration can be based on the joint application of EU Third Package rules by the EU and Russia. In this context Russia agrees to liberalize its upstream sector for foreign investors, including EU majors and also liberalizes its pipeline exports to the EU.
- At the same time the EU agrees not to put market share limitations on Russian molecules in its upstream sector and develops a benefit sharing agreement with Russia given that market integration increases aggregate benefits compared to the reference case.

The implementation of such a concept would likely result in a highly competitive Russian upstream sector. Gas producers active in Russia would have non-discriminatory access to the local as well as the EU's downstream market. Competition would imply cost-based pricing by those producers.

EU concerns about the market share of Russian gas in the EU should be less acute, given the newly competitive and non-discriminative operation of the Russian gas sector, including its upstream.

Due to decreased supply prices we expect gas wholesale prices and producer rents to decrease, while customer welfare to increase to a greater extent on the EU gas market.

[155] The notable positive exception is the Energy Community process.

Increasing traded quantity due to lower prices (increased competitiveness) could, however, partly compensate extra-EU producers for some of their lost rents. The rest of the compensation can be realized trough a benefit sharing agreement.[156]

6.5.2 Gap and sensitivity analyses

We are aware that this concept is highly speculative, politically very complex and might go beyond the scope of this study. However, we retained this concept for further quantitative analyses in order to assess the likely welfare implications of a cooperative solution that obviously addresses the fundamental problem of the EU gas market.

Due to its politically very complex nature, we cannot provide detailed gap and sensitivity analyses for this concept. Rather, we constraint ourselves to create a highly abstract modelling scenario and its quantification in Chapter 7.

6.6 Additional scenarios not selected as a main alternative

1. Full market merger

    a. Main goal: By creating one trading and balancing zone in the whole EU, higher liquidity, higher trading volumes and increased security should be achieved. In this alternative scenario, all cross-border intra-EU tariffs would be set to zero and no intra-EU capacity booking would be necessary. The current DSO-exit tariffs would remain. In order to compensate TSOs for loss of revenues due to zero CB tariffs, entry/exit tariffs at the EU border will be set. This would also lead to creation of a TCF mechanism at the EU level (similar to the Tariff Reform Scenario). As a result, the wholesale price will converge to one level across EU.

       This scenario would also be expected to lead to increased efficiency in the use of the transmission network, as only one dispatcher would be in charge of securing the most efficient transport route. Nevertheless, in order to create one EU-wide well-functioning zone, additional investment in infrastructure would be needed.

       It is expected that from the regulatory changes proposed in this alternative scenario, all EU countries will gain, but greater welfare gain would be observed in the currently less liquid markets with higher wholesale prices and less developed infrastructure.

    b. Reasons why not considered as standalone alternative regulatory scenario: This scenario is currently not politically feasible. Its implementation would require regulatory framework harmonisation across all EU countries. Moreover, based on the current zone merger in France and intended zone merger in Germany, costs needed to build additional gas transmission infrastructure to overcome currently limited availability of cross-border capacity between the zones, as discussed in Part I of this document, are expected to be of prohibitive size.

2. Implicit auctions

    a. Main goal: The aim of this scenario is to simplify trading among hubs, to increase access to daily cross-border capacity and to avoid congestion. The

[156] The elaboration of the possible benefit sharing agreement is not in the scope of the study, however, we note that according to economic theory, such compensation is feasible only if its financial sources are collected through lump-sum or extra-sector taxes, which do not affect (the variable part of) the gas price and thus customer choice.

implicit auction measure is inspired by the current functioning of the electricity market in the EU.

In this scenario, daily cross-border transmission capacities between different zones are not sold separately (as today in explicit auctions), but are made available through hub transactions on both sides (implicit auctions). Buyers and sellers on the hub can trade on a different hub, as if these hubs were merged, without the need to separately acquire the respective transmission capacities.

We assume this regulatory change to be applied only to day-ahead capacities. For the intra-day capacities, we assume the use of the remaining available capacities and their booking by the existing auction procedure or through the secondary market with capacity.

Reasons why not considered as standalone alternative regulatory scenario: Since the EGMM algorithm works as if implicit market coupling was already implemented within the EU, we do not include this proposal for further quantitative welfare analysis. Nevertheless, we consider this proposal to be viable and we suggest considering introduction of implicit day-ahead auctions in the future due to the increasingly interconnected gas market. Further, the idea of implicit market coupling on day-ahead basis and its discussion is a part of the conditional market merger scenario.

3. Storages at virtual trading point

   a. Main goal: Current access to capacities of UGS varies across the EU Member States. This scenario proposes harmonising the tariffs for storage capacities and also redefines the UGS position in the gas infrastructure.

      The aim of this scenario is to move all storage capacities to the virtual trading point so that there is no payment for gas transportation to / from the UGS. The UGS entry and exit point is therefore commercially and nominally located at the hub. We expect higher utilisation of storage capacities. After implementing this scenario's measures, UGS would also better perform its market balancing function as required by traders on the basis of BAL NC (daily deviations are offset in financial terms, i.e., based on market principles).

   b. Reason why not considered as standalone alternative regulatory scenario: Though we believe that this measure would improve market liquidity and thereby reduce wholesale prices and location spreads, the impact should be most evident in short-term trading and market liquidity, which cannot be captured by the EGMM. Further, whan we consider how much costs are allocated to the transmission to/from UGS on nation levels, tanking into account the TAR NC mentioned minimum 50% discount on these transmission tariffs, would do not consider such a scenario to be substantial enough to have meaningfull market effects. Anyway, application or zero reservation price for the transmission tariffs to and from UGS is a part of wider Tariff Reform scenario so as to keep its consistency.

4. No TPA exemptions

   a. Main goal: Multiple gas projects (both pipelines and LNG terminals) are operated or planned with an exception for TPA. Although we understand the investor's motivation is an exemption from the TPA to protect their business interests, on the other hand, we perceive the exception from TPA as a possible barrier to the gas market.

If such an exception exists in some part of the infrastructure, other shippers are forced to use alternative routes regardless of the utilisation of the exempted route. This might lead to significant inefficiencies in operating the transmission network. Furthermore, it can also lead to a market barrier creation in poorly connected markets, where there is no alternative route available. Investors can thus fundamentally influence the gas market in a given location.

Another aspect of TPA exempted infrastructure to consider is the tariff setting for its usage. In the example of the OPAL and Gazelle gas pipelines, it can be demonstrated that the agreed long-term tariffs do not fully correspond to the regulated tariffs and thus create an unjustified advantage for the investor.

This measure would prevent constructing infrastructure parts without economic reasoning and based only on political motivation.

a. Reason why not considered as standalone alternative regulatory scenario: In future, the TPA exemption is expected be used very rarely as the new CAM NC specifies an incremental capacity contracting process and therefore possible TPA exemption distorting impact would be limited. Hence, this scenario is not expected to materially increase EU welfare.

5. Regional Operation Centres (ROCs) with mandate to implement PCI infrastructure

    a. Main goal: In order to support regional cooperation between infrastructure operators (TSOs, SSOs, LSOs, but also DSOs), ROCs will be established with the aim to implement regionally beneficial projects. Individual infrastructure operators should be a part of more ROCs. For example, Austrian operators should be represented both in the Central European region and in the Southeast Europe region as they have links to both regions. The main motivation is to improve infrastructure investment decisions in situations where the implementation of PCI is blocked by certain infrastructure managers. This proposed decision-making can improve regional security of supply and multiple projects coordination, including a mandate to implement the PCI. Potential alternative of the ROC setup would be an establishment of Independent System Operator model. The operator would be responsible for operational activities of the TSOs within the given region as discussed in Section3.10.3.

    b. Reason why not considered as standalone alternative regulatory scenario: This scenario is not expected to materially increase EU welfare.

6. Minimum bi-directional capacity obligations in % of dominant flow capacities, e.g., 15% by 2025

    a. Main goal: The motivation for establishing a minimum share obligation of the reverse flow (backhaul) on the transmission network is an effort to increase security of supply and better use of the network. Currently, not all cross-border points allow reverse flow (CAM NC Implementation Report).

       The investment costs will be linked to provide the reverse flow at all cross-border points. We expect investment costs to be partially covered by PCIs, e.g., on a regional cooperation basis. In addition, cooperation with the NRAs will be necessary in order for this additional infrastructure to be incorporated into the allowed revenues scheme.

    b. Reasons why not considered as standalone alternative regulatory scenario: The impact is not expected to be material, based on the current reports on contractual and physical congestion. In addition, the implicit reverse flow requirement is integrated into several EU activities, network codes or regional cooperation due to SoS. Nevertheless, in Chapter 7.1.5 we briefly assess the likely price and welfare impacts of significant progress in implementing bi-directionality on intra-EU IPs.

7. Ownership unbundling / (regulated price caps) of EU regasification facilities

    a. Main goal: As a part of regulatory measures, unbundling has taken place in the past within the whole EU, separating the commercial interests involved in selling the commodity and operating the infrastructure necessary to transfer natural gas to end customers. Based on this experience, we consider ownership unbundling a possible logical next step for the LNG infrastructure. LNG is perceived as an increasingly important part of the gas market in the EU, and it might not be beneficial for the LNG operator and the gas trader to form one company with joined interests. This would further contribute to prevention of concentration of market power especially in combination with pipeline ownership and to have transparent TPA.

    b. Reasons why not considered as standalone alternative regulatory scenario: Regasification facilities are mostly, or will be, a regulated business with transparent third party access conditions. Only the TPA exemptions or LT capacity booking can be a source of access restrictions, yet it was approved as a necessary regulatory measure to enable initial investment. Because the restriction could be also realised by long-term capacity booking, the ownership does not represent the only limiting factor.

    c. LNG ownership unbundling represents an isolated legal measure and does not constitute a wider regulatory scenario.

7. QUANTITATIVE WELFARE ASSESSMENT OF ALTERNATIVE REGULATORY SCENARIOS BY EGMM

This Chapter summarises the results of the quantitative welfare analyses performed by the EGMM on the alternative regulatory scenarios presented and discussed in Chapter 6. For more details on the welfare concept applied see Chapter 2. For the definition and main features of the 2020 reference modelling scenario cases as well as for a detailed EGMM model description see Chapter 5 and Annex 6.

The following alternative scenarios were analysed:

- Tariff Reform Scenarios with uniform tariff increase (denoted by T*n*, where *n* is the number of different sub-scenarios). Results presented in the main text of this section.
- Tariff Reform Scenarios with harmonized EU entry tariffs (denoted by TH*n*, where *n* is the number of different sub-scenarios)
- Market Merger Scenarios (denoted by M*n*, where *n* is the number of different sub-scenarios)
- The Combined Capacity-Commodity Release Scenario (denoted by "50-50-50")
- The Extra-EU upstream – EU downstream Strategic Partnership Concept (denoted by "SP")

For each alternative scenario we apply four standard measures to describe the changes compared to the 2020 Reference Scenario values. These are (i) total welfare change, (ii) consumer welfare change, (iii) the change in EU weighted average gas wholesale price level and (iv) price divergence (measured by relative standard deviation of unweighted national gas wholesale prices). As a starting point, in the 2020 Reference Scenario the EU average wholesale price is modelled at 20.1 EUR/MWh and price divergence is at a moderate 7% level. In addition to these measures, we also compare scenarios along their welfare impacts by Member States and stakeholders as well as their implications for the overall gas supply structure of the EU.

To capture the full and separate welfare impact of each scenario, we analyse them *ceteris paribus* one-by-one except otherwise noted.

However, due to the nature of the EGMM (no short-term trading represented, perfect competition) our results cannot capture some important welfare implications of the regulatory scenarios. For example, our modelling cannot simulate daily bidding in the model and thus have no reliable measure of market liquidity. While we assume that some of the regulatory scenarios, notably the Tariff Reform Scenarios, will ease cross-border balancing and likely to improve market liquidity, we could not capture and quantify these positive impacts. The model's fundamental comparative static nature also puts a limit on simulating the outcomes of the investment incentives inherent for the regulatory scenarios. For example, we suggest that the full socialisation of the European TSO's transit related costs by the TCF mechanism in some of the investigated Tariff Reform Scenario has inherently distortive investment incentives (see the forthcoming discussion in Section 7.1.1, conclusion 4). Nevertheless, the welfare measures we apply cannot capture this disadvantage.

In Section 7.1 we summarize the welfare impacts of the alternative regulatory scenarios on the base of the 2020 Reference Scenario. Next we define five sensitivity scenarios and assess the welfare impacts of a selected set of alternative regulatory scenario implementations on those sensitivity scenarios. The five sensitivity cases are related to high demand, high and low LNG supply and two alternative Nord Stream 2 project implementation situations. Sensitivity analyses results are presented in Section 7.2. We conclude this Chapter with a policy oriented discussion of our findings (Section 7.3).

7.1 Base case regulatory scenario analyses

In this section we present welfare analysis results for twelve alternative regulatory scenarios: five Tariff Reform Scenario versions, four Market Merger Scenarios, the Combined Capacity-Commodity Release Scenario, the Strategic Partnership Concept, and the Full Implementation of Bi-Directional Capacities on the European transmission grid.

7.1.1 Tariff Reform Scenarios

Figure 49 depicts a schematic representation of a possible tariff reform, aimed at terminating tariff pancaking on the internal gas market, as described in Section 6.1.

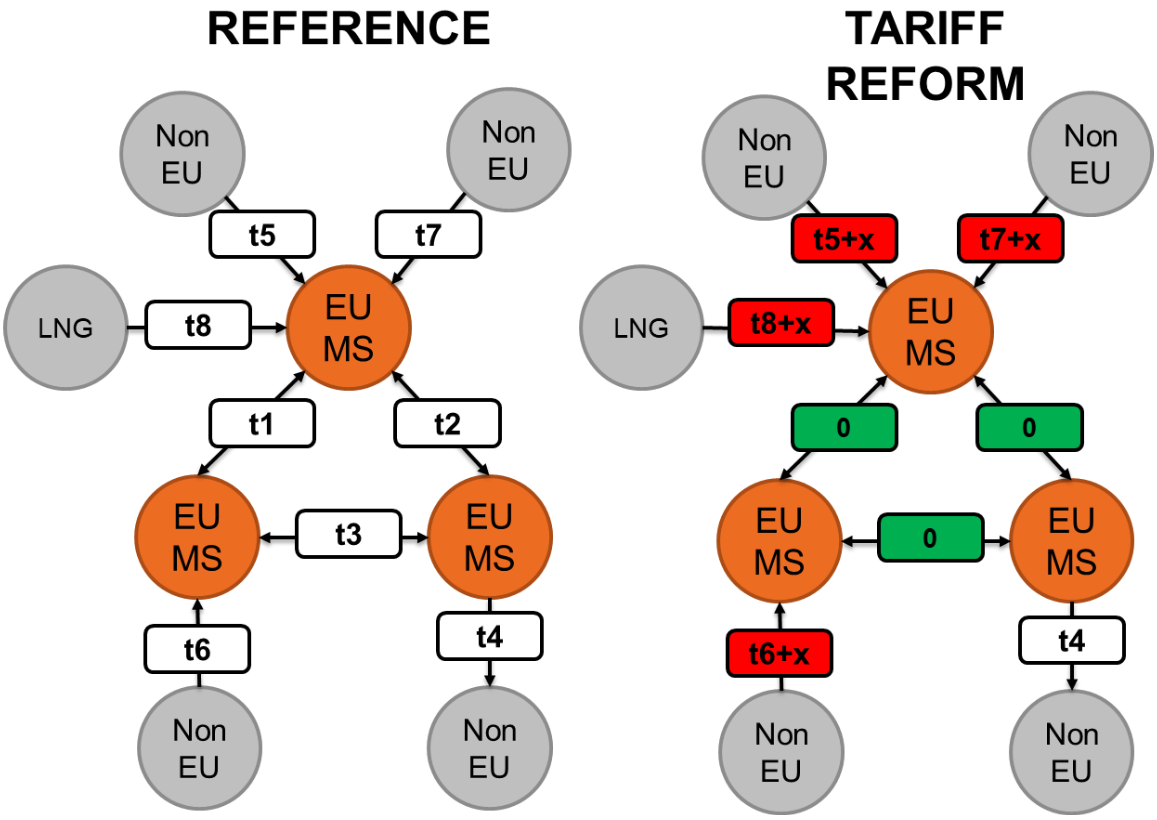

Figure 49: A schematic representation of the Tariff Reform Scenario

The major features of the proposed Tariff Reform are that within-EU IP tariffs are set to zero so that the revenue neutrality of this change for each TSO is ensured by a simultaneous tariff increas at remaining entry and/or exit points[157]. Revenue neutrality requires that the revenue collected from increased EU entry (and potentially EU exit and/or domestic exit) tariffs equals within-EU IP related tariff revenues collected by the affected TSOs *before* IP tariffs cut to zero. Since the termination of within-EU IP tariffs and the simultaneous increase in the remaining entry and/or exit tariffs are likely to change gas flows within the EU, the estimation of a tariff combination that meets this requirement is a non-trivial task.

Indeed, there might exist infinite feasible entry-exit tariff combinations with zero within-EU tariffs that, while generate sufficient revenue to ensure tariff reform revenue neutrality, have varying EU welfare implications. In principle, we could define an optimal

[157] Changing transmission tariffs to zero at storage entry and exit points is not part of the analysed scenario. Most of the cases these tariffs are already very low, so that change might not have a large effect.

tariff reform as a tariff combination (or combinations) that meets the revenue generation constraint and provides the highest welfare improvement compared to the reference case.

However, for the purpose of this study we applied a simplified modelling approach to assess the welfare impacts of the Tariff Reform Scenarios.

- Instead of searching for an optimal tariff reform, we pre-defined two feasible tariff reform designs: (1) a unit tariff (EUR/MWh) added to existing 2020 non within-EU IP tariffs, and (2) harmonized (and increased) EU-entry tariffs. In the main text of the paper we present the results for the unit tariff case as depicted in Figure 49 above. Results for the harmonized EU-entry tariff case are presented in Annex 1.
- Necessary additional unit tariffs at non within-EU IP E/E points were estimated by iteration so that aggregate TSO revenues after tariff reform implementation remained within the ±1% range of aggregate EU-28 TSO revenues in the 2020 Reference Scenario.

The following Tariff Reform Scenarios were developed based on the additional unit tariff concept.

- T1 - additional unit tariff on all EU pipeline entries; this design assumes a full EU-wide socialisation of lost cross-border tariff related TSO revenues (the latter mostly related to gas transit activities).
- T2 - additional unit tariff on all EU pipeline and LNG entries; this design assumes an equal treatment of gas exported to the EU via pipeline and LNG.
- T3 - additional unit tariff on all EU pipeline and LNG entries and domestic exits; this design combines the principle underlying T2 but allows only for a partial socialization of lost cross-border tariff related TSO revenues.
- T4 - additional unit tariff on all domestic exits; this design allows for no EU-wide socialization of lost cross-border tariff related TSO revenues.
- T5 - additional unit tariff on all EU pipeline entries and domestic exits; this design is a compromise between the T1 and T4 designs.

For the welfare analysis we estimated and applied the following unit tariff combinations for the mentioned Tariff Reform Scenarios.

Tariff Scenario	EUR/MWh unit tariff added to		
	EU Entry		Domestic Exit
	Pipeline entry	LNG entry	
T1	1.15	-	-
T2	1	1	-
T3	0.57	0.57	0.57
T4	-	-	0.85
T5	0.59	-	0.59

Table 37: Additional unit tariffs applied in the different Tariff Reform Scenarios

When implemented, the Tariff Reform Scenario makes cross-border gas trading cheaper. This will encourage increased imports by formerly more expensive countries (in CSEE in the reference) from the cheaper countries (North-West Europe in the reference) up to full price equalization or infrastructure constraints. Wholesale prices fall in importing and raise in exporting countries. In Scenarios T3-T5 the add-on tariff on domestic exit further increases wholesale prices in the exporting region (with Germany in its centre in the reference). Countries that enjoy a higher price decrease from cross-border tariff removal than the domestic add-on tariff benefit from this as well as from getting access to cheaper import sources due to internal tariff removal (like Hungary in the reference).

Table 38 provides a summary on the main impacts of implementing the above defined Tariff Reform Scenarios on the 2020 Reference case.

Tariff Scenario	Total welfare change, EURm/year	Consumer welfare change, EURm/year	Average wholesale price EUR/MWh	Price divergence %
T1	1,185	68	20.1	2 (-5)
T2	1,308	-4,177	21.0 (+0.9)	2 (-5)
T3	-469	-3,786	20.4 (+0.3)	2 (-5)
T4	-1,974	-3,378	20.0	2 (-5)
T5	-623	-1,882	20.0	2 (-5)

Table 38: Main results of base Tariff Reform Scenario analyses; welfare changes for EU countries (in brackets change compared to 2020 reference)

We draw the following general conclusions from the welfare analysis of the base case Tariff Reform Scenarios.

1) The typical pattern of Tariff Reform Scenario welfare impacts under 2020 reference market conditions is that they rather redistribute than increase welfare through increased cross-border trading while support price convergence (see last column of Table 38 and Figure 50). This means that tariff reforms seem to support the EU's long term objective of full market integration.

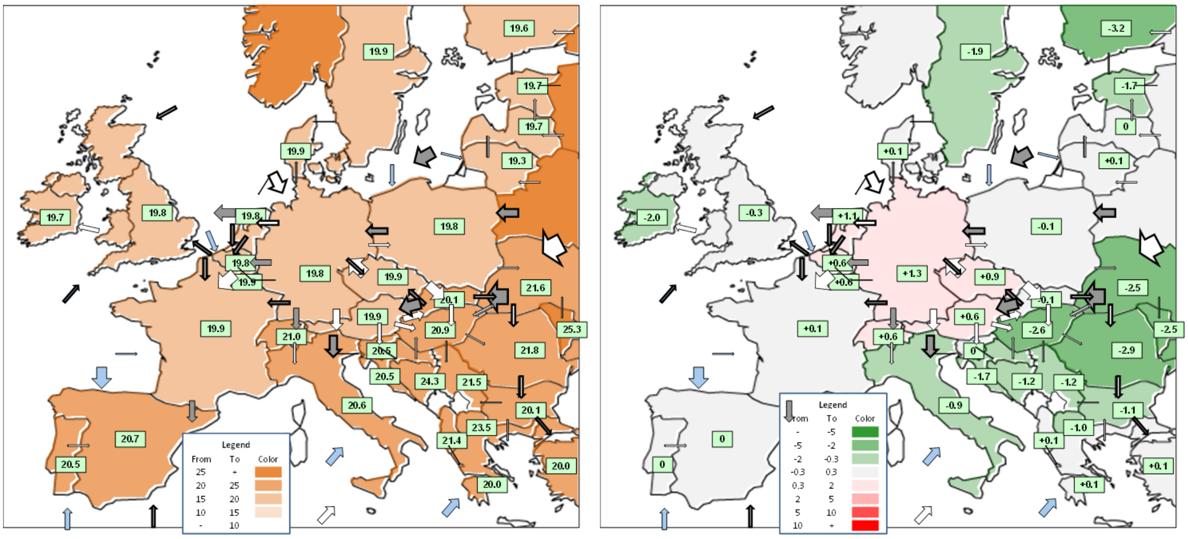

Figure 50: Wholesale prices in the T1 (additional unit tariff on all EU pipeline entries) Tariff Reform Scenario (left) and wholesale price changes compared to the 2020 Reference case (right), EUR/MWh

2) The short-term total welfare impact of the Tariff Reform Scenarios is moderately positive (T1 and T2) or negative (T3-T5). The only case with positive total and consumer welfare impacts is when the additional unit tariff is applied exclusively for EU pipeline entries (T1). A common pattern of Tariff Reform Scenarios is that while their total welfare impact remains moderate, they quite significantly redistribute welfare within the EU due to increased trade between the NW and CSEE regions. As a consequence, gas prices tend to increase in the Germany-Benelux-Czech-Austrian region and decrease in the rest of the EU as well as the Energy Community countries.

3) Additional tariffs on LNG entry points (T2 and T3) seem to a large extent translate to immediate EU average wholesale price increases and thus have detrimental consumer welfare impacts. This indicates that LNG is the marginal supply source to

the EU in the 2020 Reference Scenario.[158] Price increase is the highest and happens in most of the EU countries under the T2 scenario (see Figure 51). Due to increased producer and midstreamer profits however, the total welfare impact of the T2 scenario is positive. These results suggest that tariff discrimination between pipeline vis-a-vis LNG entry points might be a critical tariff reform design issue.

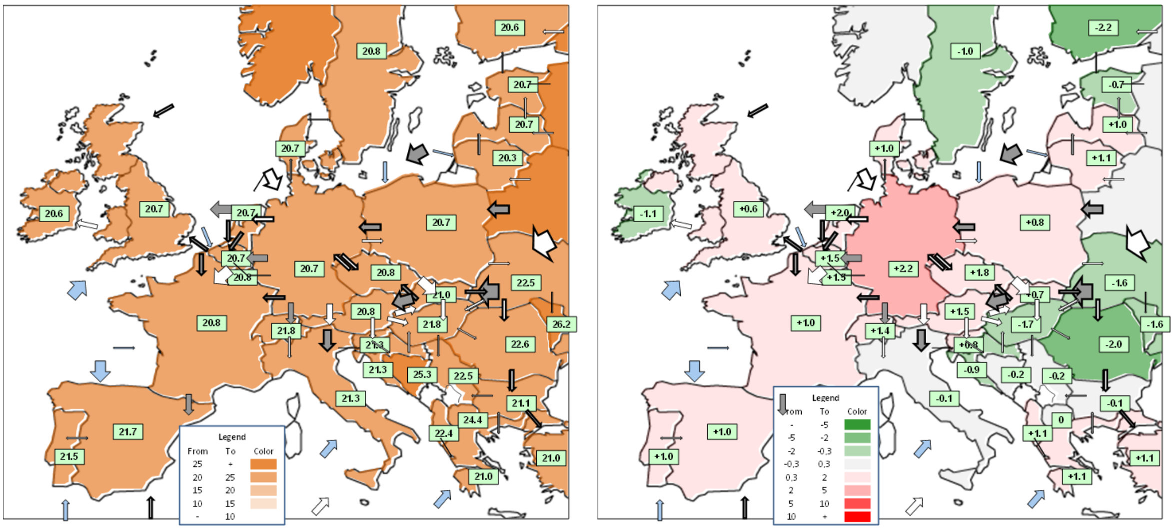

Figure 51: Wholesale prices in the T2 (additional unit tariff on all EU pipeline and LNG entries) Tariff Reform Scenario (left) and wholesale price changes compared to the 2020 Reference case (right), EUR/MWh

4) Those scenarios involving additional unit tariffs on domestic exit points (T3-T5) provide the worst results from a welfare point of view. In these cases the implementation of the Tariff Reform Scenario decreases consumer and total welfare. Scenario T4 with additional unit tariffs equally put on pipeline and LNG entry and domestic exit points is the inferior case.

   Note however that our results are based on the assumption that IP related TSO tariffs/revenues are set perfectly by NRAs in the Reference case so that they reflect only justified costs, the most of which being related to gas transit related activities of the TSOs. Once we relax this assumption and allow for the possibility of imperfection in NRA tariff setting, a reform design allowing only for partial EU-wide socialization of IP related revenues (costs) through introducing additional unit tariff increases at domestic exit points (T3-T5) will provide improved incentives for NRAs to scrutinize TSO costs. The pressure for NRAs to increase domestic exit tariffs under these schemes will make them more attentive to the costs underlying existing domestic exit tariffs as well as those related to TSO transit activities, including those related to new cross-border investments. This is because both will add to the pressure for domestic price increase that NRAs tend to dislike. While full EU-wide socialization of IP related cost (like in scenario T1) will make TSOs and NRAs insensitive to transit related cost escalation and thus encourage over-investment into new cross-border infrastructure, a move to partial socialization could significantly reduce such distorted incentives.

5) In more general terms we conclude that under the current and expected 2020 market conditions, characterized by moderate demand, low prices and a high level of price convergence across the EU, the investigated Tariff Reform Scenarios are not about reducing average wholesale price levels but promoting further market integration and price convergence. The gas infrastructure that is expected to be in place in 2020 does not put an effective constraint on such a close-to-full market

[158] This impact is perhaps the most apparent in case of Portugal and Spain.

integration. However, the welfare implications of the Tariff Reform Scenarios are moderate and seem sensitive to key design issues, especially the choice of points to collect TCF revenues.

Tariff Reform Scenario with harmonized tariffs

We also defined and analysed Tariff Reform Scenario by making certain entry and exit tariffs identical in order to collect TCF revenues.

Similarly to the add-on tariff case, we defined the Tariff Reform Scenario with harmonized tariffs as follows:

- TH1 – Identical unit tariff on all EU pipeline entries, ensuring the collection of IP tariff related TSO revenues in the 2020 reference; this design assumes a full EU-wide socialisation of lost cross-border tariff related TSO revenues from unified and increased EU pipeline entry tariffs.

The versions of the TH1-TH5 scenarios were applying the same principle for different combinations of EU entry, LNG entry and domestic exit points in the same order as in the T1-T5 scenario cases.

Table 39 summarises the welfare implications of the Tariff Reform Scenario with harmonized tariffs and Figure 52 illustrates the price impact of TH1 (parallel to the T1 scenario depicted in Figure 50 above).

EURm	Consumer surplus	Domestic producer	Storage arbitrage	LTC holder	TSO	SSO	LSO	Total welfare
TH1	74	105	-2	1,078	47	15	-53	1,265
TH2	-5,713	1,510	4	5,704	5	17	-110	1,416
TH3	-5,375	894	19	4,242	-24	16	-109	-338
TH4	-3,440	-107	30	1,608	6	13	-76	-1,966
TH5	-1,905	-22	18	1,362	26	11	-71	-581

Table 39: Welfare effects of the harmonized tariff scenario in the reference case

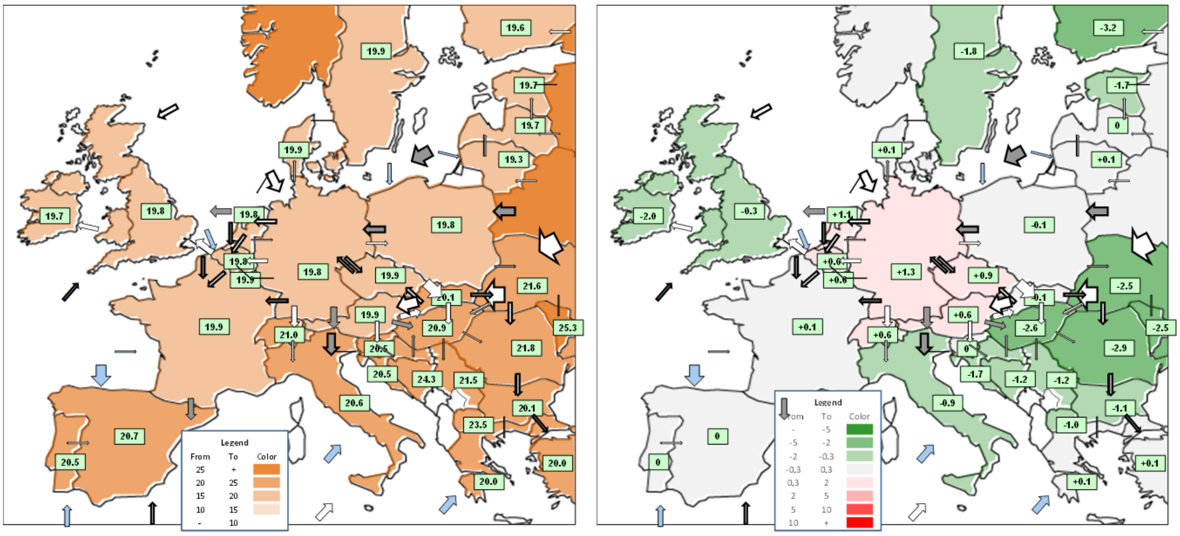

Figure 52: Wholesale prices in the TH1 (identical EU pipeline entry tariffs at EUR 1.84/MWH) Tariff Reform Scenario (left) and wholesale price changes compared to the 2020 Reference case (right), EUR/MWh

As for TH1, the magnitude and pattern of price and welfare changes are almost identical to the scenarios with add-on tariffs. We conclude that this Tariff Reform Design does not change our general conclusions on the performance of the Tariff Reform Scenario on the 2020 reference case.

7.1.2 Market Merger Scenarios

Sections 6.2 and 6.3 discuss the rationale, the likely features and expected formations of trading zone mergers and conditional market mergers within the EU. The common feature of these Market Merger Scenarios is that cross-border tariffs within the merged zones are eliminated and the lost TSO revenues are collected from additional tariffs on the remaining E/E points of the zones. Figure 53 depicts the schematic representation of a possible market merger design, aimed at creating an integrated trading zone formerly separated by cross-border tariffs.

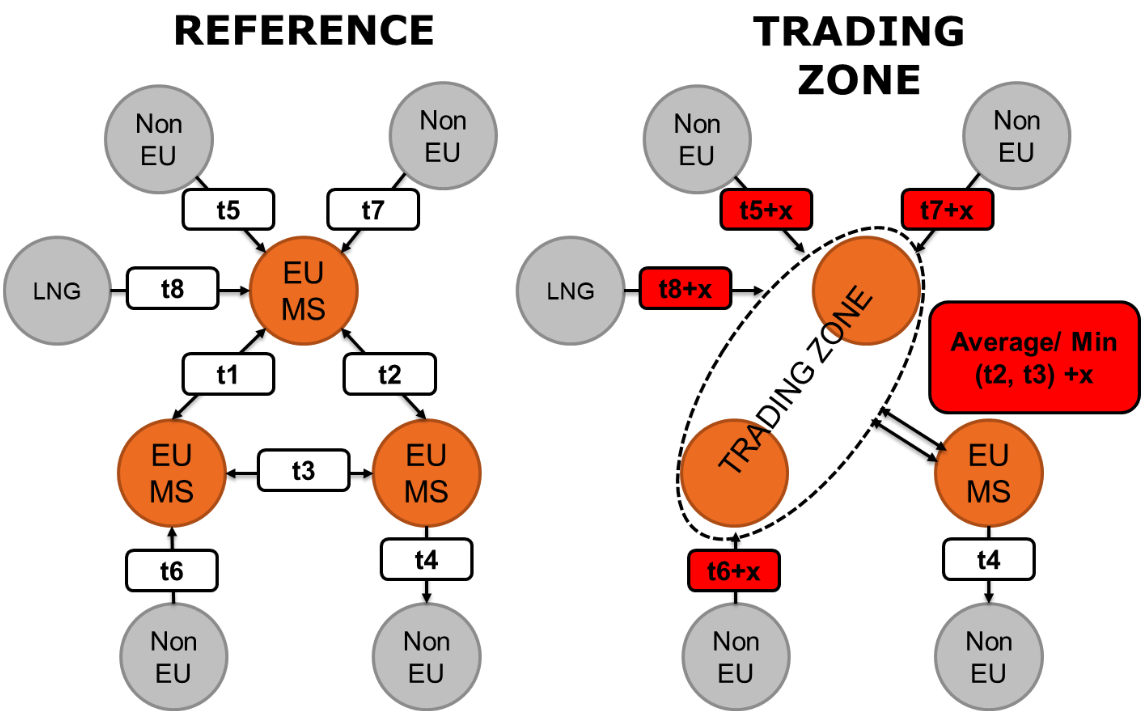

Figure 53: A schematic representation of a Market Merger Scenario

For the purpose of this study we applied the following modelling approach to assess the welfare impacts of the Market Merger Scenarios.

- We assume that no transmission bottlenecks can remain within a merged zone. Note that we do not calculate with transmission investment costs even if we implicitly assume an expansion of cross-border transmission capacities for a given scenario. Our analysis is thus limited to estimating the benefits (in terms of total welfare improvement) but not the costs of Market Merger Scenarios.
- Trading zone merger regions are defined in accordance with the regions described in Section 6.2 and illustrated in Figure 46. The following trading zone mergers are then analysed.
  - M1 – Spain and Portugal
  - M2 – Germany – The Netherlands – Belgium – Luxemburg – Czech Republic
  - M3 – Romania and Bulgaria
  - M4 – Lithuania – Latvia – Estonia – Finland
- In the context of market merger analysis we also identified some additional candidate zones for conditional market merger. For this purpose we defined "zones of no congestion" based on model outputs for the Tariff Reform Scenario version T1. We selected the T1 scenario for this exercise because the removal of

cross-border tariffs intensifies cross-border trading and the related IP utilization level most in this scenario. If the level of IP utilization between two neighbouring zones remains moderate even in this scenario, that means that the two zones have no effective physical constraint to go ahead with market merger. We applied three different criteria for defining "no congestion" for two neighbouring zones: (1) the level of IP utilization does not exceed 50% in any of the twelve modelled months, (2) there is no month when the level of IP utilization between the two zones exceeds 90% and (3) annual average IP utilization does not exceed 50%. Based on these criteria we identified the following natural candidates for conditional market merger (in brackets those countries that qualify for conditional market merger only under one of the above criteria).

  - Germany-Czech Republic-(Belgium-Denmark)
  - (Finland)-Estonia-Latvia

- These zones are sub-zones of the M2 and M4 trading zone mergers (except for the case of Denmark). For this reason we decided not to enhance the M1-M4 set of market merger cases for the present study.

We carried out the welfare analysis of Market Merger Scenarios one by one, that is assuming the implementation of only one merger scenario on the 2020 Reference and withdrawing it when analysing the subsequent one (similar to the PINT method in case of infrastructure analysis).

The values in Table 40 indicate the required additional unit tariff for each zone entry points needed to compensate TSOs for their lost IP tariff related revenues for each trading zone merger case analysed in this study.

Trading zone merger	EUR/MWh unit tariff added to zone entries
M1: PT-ES	0.1
M2: DE-NL-BE-LU-CZ	0.2
M3: RO-BG	1
M4: LT-LV-EE-FI	0.6

Table 40: Estimated additional unit tariffs for zone entry points by Market Merger Scenarios

Table 41 provides a summary on the main impacts of implementing the above defined Market Merger Scenarios on the 2020 Reference case.

Market Merger	Total welfare change, EURm/year	Consumer welfare change, EURm/year	Average wholesale price EUR/MWh	Price divergence %
M1: PT-ES	-8	-21	20.1	8 (+1)
M2: DE-NL-BE-LU-CZ	219	-266	20.2 (+0.1)	7
M3: RO-BG	-23	415	20 (-0.1)	6 (-1)
M4: LT-LV-EE-FI	22	123	20.1	7

Table 41: Main results of Market Merger Scenario analyses (in brackets: change compared to 2020 Reference)

Portugal-Spain

In case of the Spain-Portugal market merger, we see limited welfare effects in the 2020 reference case (Table 42). Wholesale prices and gas flows for the Spanish and Portuguese markets are already aligned in the 2020 reference case due to ample interconnection capacity and also because the implementation of the Third Package brings lower cross-border tariffs and higher price convergence. Furthermore, oversupplied LNG market and low European demand brings higher price convergence in countries well-connected to global LNG markets. The slight difference of 0.1 EUR/MWh is annual prices is caused by the different monthly consumption patterns of the two countries, as monthly prices are identical.

	ES-PT E/E tariff, EUR/MWh	ES price, EUR/MWh	PT price, EUR/MWh
2016 Status Quo	1.93	19.5	19.9
2020 Reference (assuming full Third Package implementation)	1.85	20.7	20.6
2020 Merger	0	20.7	20.5

Table 42: IP tariffs and wholesale prices for Spain (ES) and Portugal (PT) before and after an assumed market merger by 2020

We must stress that a current merger, predating the full implementation of the Third Package, may bring better price convergence and higher benefits for a Spanish-Portuguese market merger. However, our task was to assess the effect of regulatory and tariff options *after* the implementation of the Third Package. In this case, price and welfare effects are indeed close to zero.

North-West

The estimated price impacts of a NW trading zone merger by Germany, the Benelux states and the Czech Republic are depicted in Figure 54. The simulation indicates a Belgian and Czech price decrease at the cost of a slight German price increase.

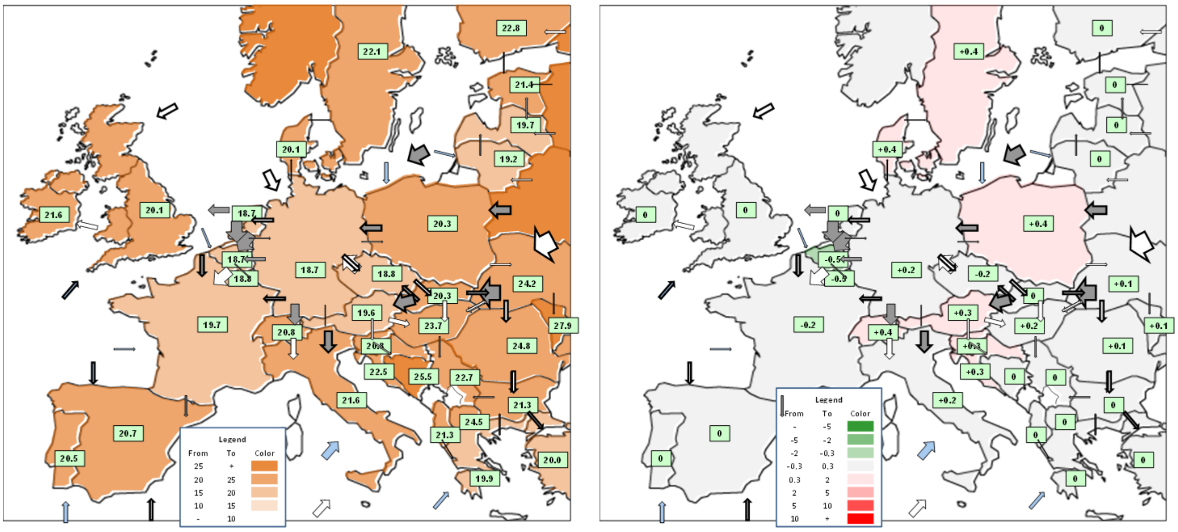

Figure 54: Wholesale prices in the M2 (DE-NL-BE-LU-CZ) Market Merger Scenario (left) and wholesale price changes compared to the 2020 Reference case (right), EUR/MWh

Due to the add-on tariff put on the entry points of this relatively low priced merged zone, some of the neighbouring countries around the zone become more expensive due to an increased cost of trading between the zones. An exception is for France where the wholesale price drops due to the NW merger.[159] Price increase is estimated to be the

[159] The explanation for the French (FR) price decrease is that the zone merger related Belgian (BE) wholesale price drop (EUR 0.5/MWh) is larger than the simultaneous add-on tariff to the BE-FR IP tariff (EUR 0.18/MWh).

most significant in Denmark, Sweden, Poland, Austria and Croatia. The merger increases slightly the EU's average wholesale price level and thus leads to a slight deterioration of overall consumer welfare. Due to the positive impact of the price increase on producers and wholesalers, the total welfare impact of this scenario is positive.

Romania-Bulgaria

The Romania-Bulgaria market merger leads to a significant price drop and related annual consumer welfare improvement of over EURm 400 for Romania and Hungary by allowing increased access to TAP gas sources (Figure 55).

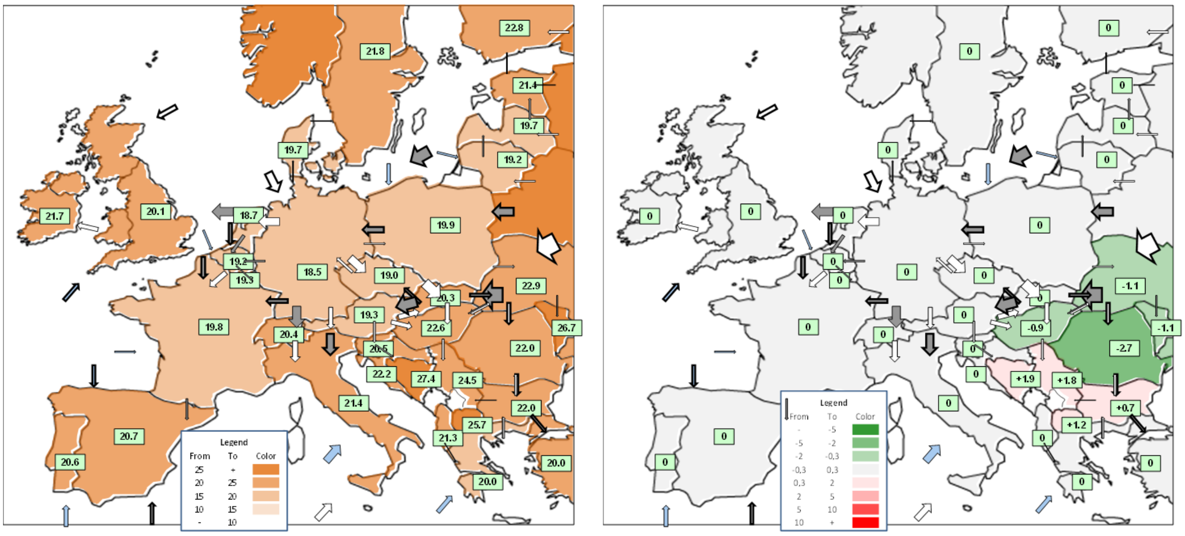

Figure 55: Wholesale prices in the M3 (RO-BG) Trading Zone Merger Scenario (left) and wholesale price changes compared to the 2020 reference case (right), EUR/MWh

Ukraine and Moldova also benefits from this change through dropping wholesale prices. All this happens at the cost of a slight price increase in Bulgaria and a number of TAP gas consuming Energy Community countries. Reduced profits of gas producers in Romania and Hungary and reduced TSO congestion revenues result in a slight overall decrease in total welfare.

Baltic merger

While the merger of the Lithuanian, Latvian, Estonian and Finnish gas markets do not impact overall EU gas wholesale price level and divergence, the total welfare impact of this merger is positive so that consumers of the merged zone are the largest winners of all the stakeholders. This is largely the result of the merger allowing Lithuanian LNG to compete with Russian gas in the entire region that formerly had the highest unilateral import dependence on Russian supplies. Here again the above benefits should be contrasted with the additional infrastructure investment costs this market merger should require.

This change boosts arbitrage on the BE-FR interconnector and almost double the flow from Belgium to France compared to the 2020 reference.

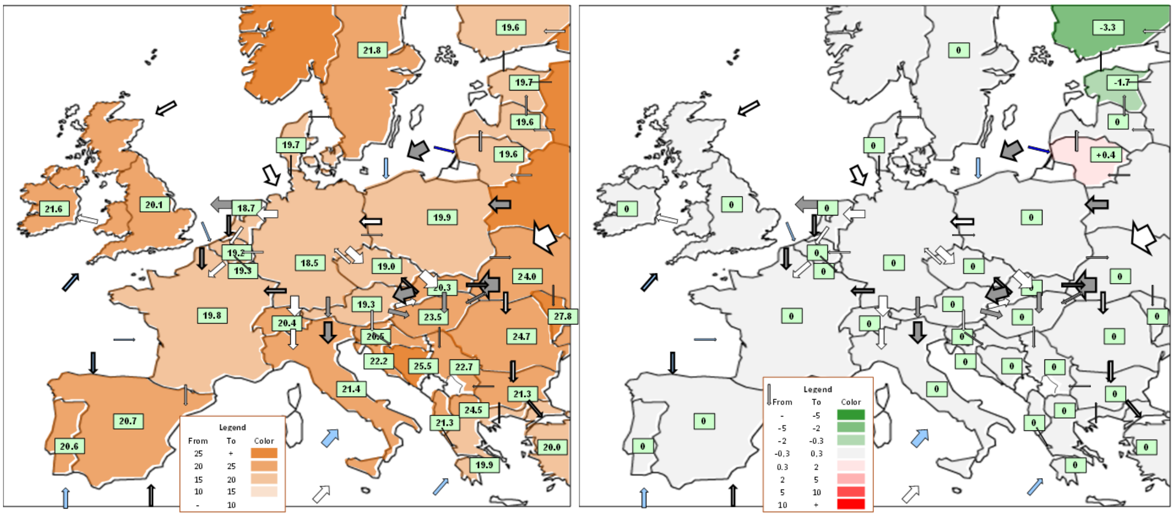

Figure 56: Wholesale prices in the M4 (LT-LV-EE-FI) Market Merger Scenario (left) and wholesale price changes compared to the 2020 Reference case (right), EUR/MWh

7.1.3 The Combined Capacity-Commodity Release Scenario (50-50-50")

Figure 57 depicts a schematic representation of the changes proposed in the Combined Capacity-Commodity Release Scenario, as described in Section 6.4. The scenario proposes a simultaneous increase up to 50% in the share of short term transmission capacities for both existing and new infrastructure (50-50) and an obligation for gas producers/importers to sell at least 50% of their gas at the nearest VTP to their entry into the transmission grid on EU territory (50). The objectives of this scenario are to prevent market foreclosure (capacity release) and improve market liquidity (commodity release) simultaneously.

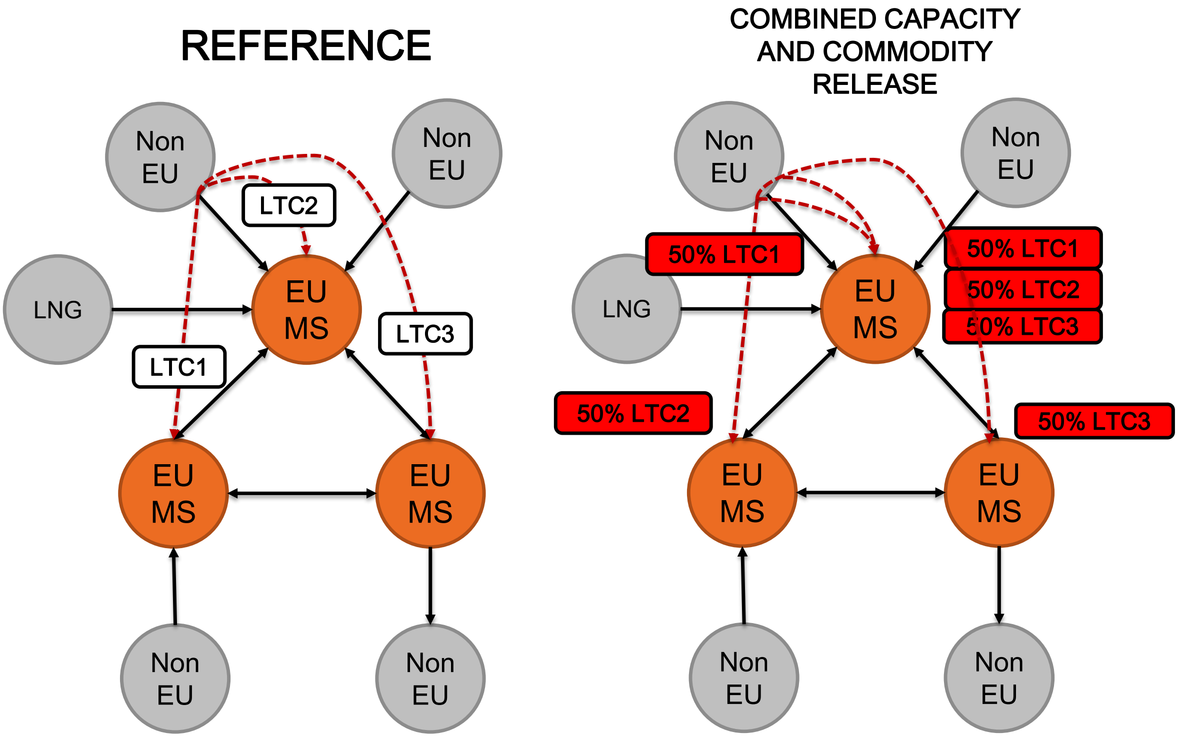

Figure 57: Schematic representation of the Combined Capacity-Commodity Release Scenario

When modelling this scenario, we assume the release of long-term commodity and capacity contracts within the EU. 50% of the contracted volumes is sold at the first market after the gas enters EU territory. Furthermore, capacity bookings related to these contracts is to be lifted. It is expected that the newly released volumes and capacities enhance trade and offer new possibilities for market players. The looser constraints on the European infrastructure allow for more spot trading opportunities and arbitraging between the markets. The commodity volumes to be released at the first European markets after entry (DE, PL, HU, SK, RO) total ~70 bcm/year.

The volumes released are priced at the original contract price minus the respective transportation cost (e.g. for an Italian contract transiting via Slovakia and Austria, the price at Slovakia is the Italian contract price minus the transmission fees to be paid at the Austrian-Italian and Slovakian-Austrian borders).

The impacts of the 50-50-50 scenario on the 2020 Reference are depicted in Figure 58 and detailed in Table 43.

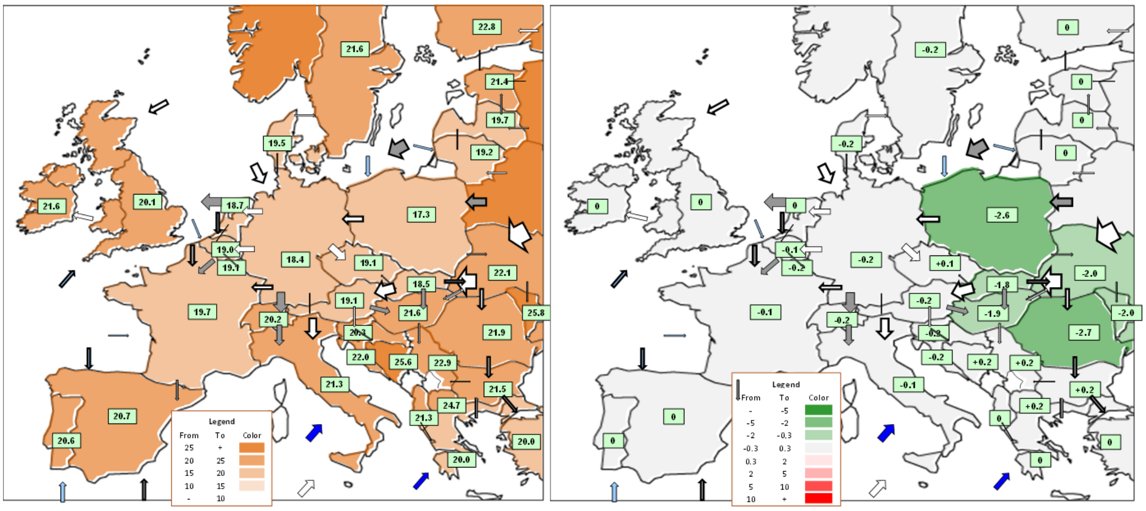

Figure 58: Wholesale prices in the Combined Capacity-Commodity Release Scenario (left) and wholesale price changes compared to the 2020 reference case (right), EUR/MWh

The price and welfare effects of the 50-50-50 scenario are overall positive and rather significant. While the scenario leads to a moderate EU-wide average wholesale price decrease, its downward price impact is more significant on the more expensive, less liquid and potentially more foreclosed markets of Poland, Slovakia, Hungary and Romania than on the German market and its neighbours. Note that this scenario does not increase prices in any of the EU countries, except for a slight increase in Bulgaria.

Annual consumer welfare benefits exceed EUR 1.5 billion for the affected EU countries (see Table 43). Once Energy Community related changes are considered, the positive welfare impacts of the scenario improve further. For example, the consumer welfare improvement for the combined EU and Energy Community exceeds EUR 2.3 billion annually, Ukrainian and Moldavian consumers being the largest winners from the EnC.

	Total welfare change, EURm/year	Consumer welfare change, EURm/year	Average wholesale price, EUR/MWh	Price divergence, %
Capacity-Commodity Release	616	1,546	20.0 (-0.1)	7%

Table 43: Main results of the Combined Capacity-Commodity Release Scenario analyses for the EU countries (in brackets: change compared to 2020 reference)

We conclude that the 50-50-50 scenario can successfully address some critical problems of the CSEE region by reducing the risk of market foreclosure and increasing product market competition. The resulting price decrease brings relief for the region without hurting other EU customers.

7.1.4 The Extra-EU upstream – EU downstream Strategic Partnership Concept

As opposed to the foregoing alternative regulatory scenarios, the Extra-EU upstream – EU downstream Strategic Partnership Concept is a cooperative regulatory concept aiming at increasing the combined welfare of the EU and Russia (as an example of a non-EU producer) compared to non-cooperative regulatory scenarios. The Strategic Partnership Concept, described in Section 6.5, assumes that the EU and non-EU producers (represented by Russia in this example) enters into a mutually beneficial agreement to integrate their gas markets in a fundamental way. This market integration can be based on the joint application of EU Third Package rules by the EU and Russia. In this context Russia agrees to liberalize its upstream sector for foreign investors, including EU majors and also liberalizes its pipeline exports to the EU. At the same time the EU agrees not to put market share limitations to Russian molecules in its upstream sector and develops a benefit sharing agreement with Russia given that market integration increases aggregate benefits compared to the reference case.

In order to model the likely welfare implications of such a dramatic concept, we had to change our assumptions about the major characteristics of Russian gas deliveries to the EU market.

For the Strategic Partnership Concept we first assume an effectively competitive Russian upstream sector. A major consequence of such a change would be that upstream companies, active in Russia, would be willing to sell gas to the EU market close to their marginal cost. We estimated the marginal cost of Russian spot gas at 10.1 EUR/MWh at the Russian border (the sum of production cost, internal transportation, royalty and export duty)[160] and Norwegian pricing to adapt to this change in the Russian situation to avoid being crowded out by Russian and/or LNG supplies. We also "dissolve" LTCs in our modelling and assume that the only remaining constraint to selling gas of Russian origin to the EU is pipeline capacity. Finally, we assume that the different supply routes to deliver gas of Russian origin to EU downstream customers are competing so that the within-EU supply route for this gas is optimized based on entry/exit tariffs.

Figure 59 depicts the major impacts of the Strategic Partnership Concept on wholesale prices and trade flows.

[160] James Henderson (2016) estimated the cost of Russian gas at the German border at approximately $3.5/MMBtu in 2016, which means a cost of Russian gas at the Russian border of about $2.58/MMBtu. In his comment Korchemkin (2016) claims the cost at the Russian border to be at a higher $3.86/MMBtu (production: 0.88; transmission: 1.45; export duty: 1.53). We take the average of these estimates and convert $/MMBtu to EUR/MWh. This provides us with a 10.1 EUR/MWh cost estimate for the Russian gas at the Russian border.

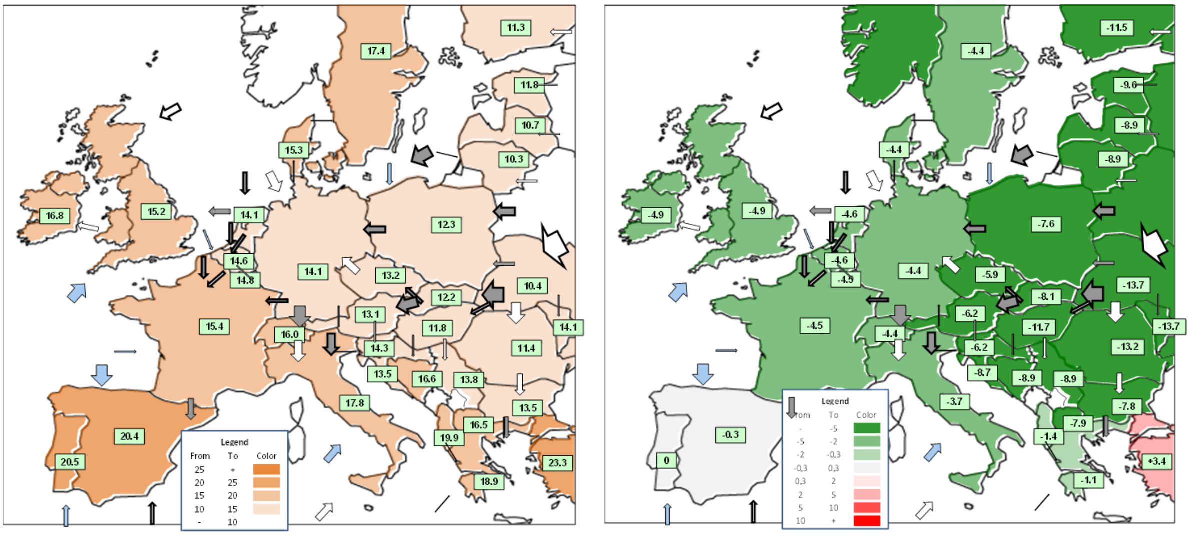

Figure 59: Wholesale prices in the Strategic Partnership Concept (left) and wholesale price changes compared to the 2020 reference case (right), EUR/MWh

The impacts of this concept compared to the former, non-cooperative scenarios is an order of magnitude larger. The TTF price drops close to Henry Hub levels while the EU average gas wholesale price level drops by 5 EUR/MWh. In this case the regions closer to Russian borders become relatively cheaper within the EU since the price drop in the CSEE region (and the Energy Community countries) is often two digit. The significantly changing price environment makes within-EU infrastructure constraints effective. East-West and East-South pipelines become congested at several points. The ability of countries/regions with limited network connections to the NW market to benefit from this concept is limited. In this concept the Iberian peninsula remains the most expensive region of the EU. Increased congestion increases price divergence from the 2020 Reference from 7% to 20%.

The significant price decrease due to an integrated and competitive operation of the Russian upstream and EU downstream markets brings a significant annual EUR 24 billion consumer welfare increase for EU customers. The related total EU welfare increase is EUR 13.3 billion per year.

In order to judge the economic rationale of this concept, we should compare these benefit changes to profit changes on Russian gas sales to the EU. This requires further detailed modelling analyses that is beyond the scope of this study.

However, some early policy conclusion can be drawn form the foregoing analysis. The modelling results suggest that a stronger and more fundamental integration of the EU gas market with a competitive Russian (and perhaps Norwegian) upstream sector, based on production and export liberalisation could potentially boost the international competitiveness of the EU gas market. Third Package market rules implementation in the exporting country (or countries) could be a sufficient framework for such an integration.

This vision of a strategic partnership between the EU and its extra-EU pipeline suppliers, most notably Russia, might seem unrealistic and beyond control for EU policymakers. The producer can also question giving up part of its current production rent. However, unless increased upstream competition can result in wholesale price decreases and related welfare improvement in the EU that outweighs the related loss in production rents, the possibility for cooperative solutions exists. Such solutions could provide higher allowed EU market shares for those producing countries willing to implement upstream sector reforms promoting competition and liberalisation. A joint analysis of producer countries' profit and EU-welfare development could provide further insight into the feasibility of such policy choices.

The recent build-up of strong Russian independent gas producers, their growing interest in reaching Western export markets[161] and the related high-level Russian discussion about a potential introduction of EU-conform market rules and export liberalisation[162] could be the right momentum for both sides to better explore the scope for cooperative solutions and their potential risks and benefits. EU policymakers could put these issues on the agenda when focusing future Russia-EU energy dialogue or when bargaining with Russia on Nord Stream 2 or promulgating agreements with Gazprom on DG Competition cases.

7.1.5 Bi-directionality fully implemented on the European transmission grid

Our last base case regulatory scenario analysis investigates how 2020 reference market conditions would change if the European transmission grid was made fully bi-directional. Certainly, this is neither an alternative regulatory scenario put forward by this study nor it qualifies as an implementation of the Third Regulatory Package. However, as we indicated in Chapters 3.2.1, the lack of bi-directional capability of interconnectors might be considered either as an LNG evacuation or trade barrier and might hamper further market integration.

As we already discussed in Chapter 4.2.2, the newly adopted gas supply security regulation (Regulation 2017/1938) obliges transmission system operators to enable permanent physical capacity to transport gas in both directions ('bi-directional capacity') on all interconnections between Member States. In the following analysis we assume that no exemption is granted to this obligation and the European grid becomes fully bi-directional.

To illustrate the likely impact of a hypothetical, widespread implementation of this obligations on the EU gas market, we run a simulation assuming 100% availability of bi-directional capacity for each existing EU internal IP in the 2020 Reference Scenario. The results are depicted in Figure 60 and Table 44.

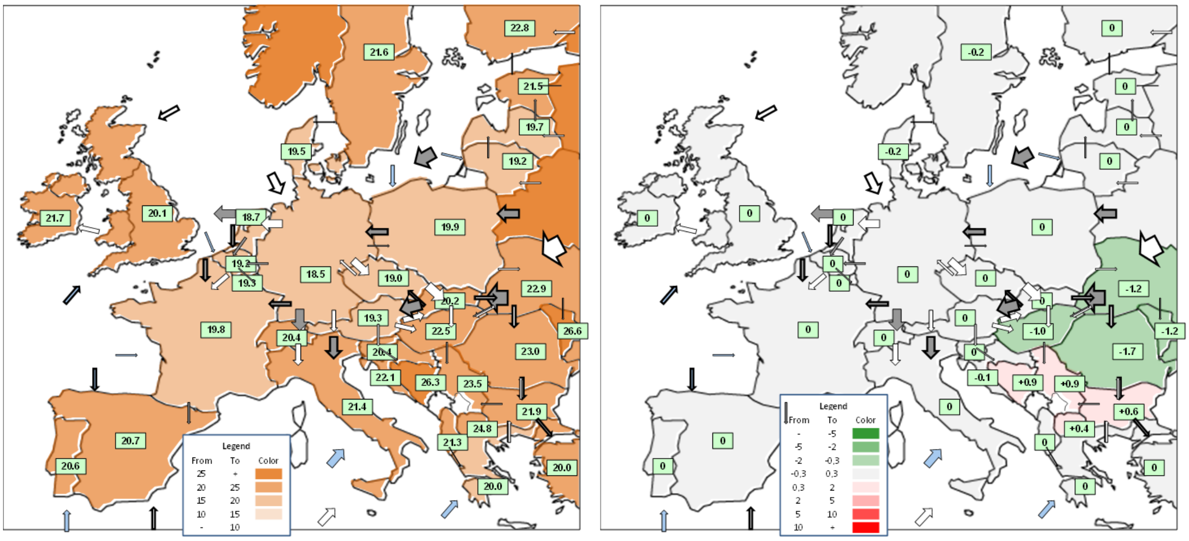

Figure 60: Wholesale prices in the full bi-directional case (left) and wholesale price changes compared to the 2020 reference case (right), EUR/MWh

Source: REKK EGMM simulation

[161] http://energypost.eu/russia-starts-lng-exports-from-yamal-what-it-means-for-europe/

[162] See e.g., the interview with *Anatoly Golomolzin, deputy head of Russia's Federal Antimonopoly Service (FAS) in January 2017.* https://en.fas.gov.ru/press-center/fas-in-media/detail.html?id=48603

	Total welfare change, EURm/year	Consumer welfare change, EURm/year	Average wholesale price, EUR/MWh	Price divergence, %
Capacity-Commodity Release	-78	360	20.0 (-0.1)	6% (-1)

Table 44: Main results of the full bi-directional case analyses for the EU countries (in brackets: change compared to 2020 reference)

As the figure illustrates, it is only the Trans-Balkan pipeline where the implementation of the additional bi-directional capability could bring a significant price reduction for some CSEE countries. This impact is mostly due to better access to the TAP papieline by the benefiting countries The measure would result in sizeable consumer welfare gains but also cause losses to producers in Romania and Hungary and the Slovak TSO, overall resulting in a slight total welfare loss.

We disregard from the further sensitivity analysis for this measure.

7.1.6 Some additive comparative analyses on base case regulatory scenarios

Table 45 and Table 46 provide details on the total welfare impacts of base case regulatory scenarios on the 2020 reference by country and stakeholder groups, respectively.

EURm	T1	T2	T3	T4	T5	M1	M2	M3	M4	50-50-50	SP
AT	-277	-55	-48	-40	-141	0	25	-13	0	180	673
BE	77	80	3	-62	-8	0	-136	0	0	-53	662
BG	-210	-193	-205	-213	-211	0	0	36	0	14	-143
CZ	-209	-219	-212	-211	-208	0	-27	-3	0	-95	296
DE	1,492	1,735	1,084	571	937	0	237	-1	0	-352	2,319
DK	-22	-9	-17	-24	-23	0	5	0	0	-2	-60
EE	-9	-16	-15	-14	-12	0	0	0	-11	0	87
ES	53	85	-31	-103	-42	-41	-19	-16	-27	-36	-18
FI	54	40	31	24	37	0	0	0	25	0	221
FR	46	-38	-79	-110	-41	0	21	0	0	116	2,629
GR	88	135	75	-11	56	39	13	36	3	36	42
HR	5	-3	4	9	8	0	-6	-5	0	-3	115
HU	86	28	41	52	68	0	-13	8	0	63	903
IE	37	-5	21	42	41	0	0	0	0	0	236
IT	-178	-276	-254	-235	-212	-7	-47	0	0	525	1,538
LT	31	47	24	11	17	-8	-6	-3	34	12	247
LU	-8	-19	-12	-6	-7	0	7	0	0	2	60
LV	6	7	-3	-11	-3	0	0	0	-2	0	79
NL	167	343	280	212	189	1	-64	1	0	44	-4
PL	304	285	28	-193	20	0	-2	-9	0	259	1,213
PT	14	22	18	3	11	10	0	3	0	7	32
RO	72	26	-57	-127	-41	0	-2	48	0	27	281
SE	17	-5	8	20	19	0	-9	0	0	4	111
SI	-11	-19	-15	-11	-10	0	-3	-2	0	1	62
SK	6	-96	-551	-940	-538	0	47	-102	0	-189	-101
UK	-447	-572	-589	-607	-530	0	198	0	0	55	1,837
Total	1,185	1,308	-469	-1,974	-623	-8	219	-23	22	616	13,319

Table 45: Member state level total welfare change implied by the base case regulatory scenarios on the 2020 Reference, million Euros per year

Scenario	Consumer	Domestic Producer	Storage arbitrage	LTC holders	SSO	TSO	LSO	Total
T1	68	110	-3	1,106	15	-43	-68	1,185
T2	-4,177	1,115	3	4,513	14	-74	-86	1,308
T3	-3,786	457	17	2,931	13	-27	-75	-469
T4	-3,378	-108	30	1,603	13	-58	-76	-1,974
T5	-1,882	-36	15	1,329	11	-3	-57	-623
M1	-21	3	1	12	0	-2	-2	-8
M2	-266	86	20	364	6	44	-35	219
M3	415	-288	-29	11	-1	-147	15	-23
M4	123	0	5	-84	3	-15	-10	22
50-50-50	1,546	-448	-1	-19	14	-440	-36	616
SP	24,148	-6,591	80	-8,376	15	4,219	-175	13,319

Table 46: Total welfare change by stakeholder groups implied by the base case regulatory scenarios on the 2020 Reference, million Euros per year (without Malta)

It seems apparent that the Strategic Partnership Concept could bring about the most significant positive welfare change for EU customers by the investigated regulatory scenarios. In terms of total welfare improvement it is France, Germany, the UK, Italy and Poland that could gain the most from this scenario due to their market size. However, the welfare figures for this scenario should be corrected by the outcome of a yet undefined benefit sharing agreement between the EU and Russia.

Aside from the SP scenario, it is interesting to note that the welfare impacts of some base case regulatory scenarios seem to be quite consistent for some countries. For example, the total welfare impact of the different Tariff Reform Scenarios is consistently and significantly positive for Germany, The Netherlands, Portugal and Hungary and negative for the UK, Italy, Bulgaria, the Czech Republic and Austria.

The implementation of the base case regulatory scenarios implies the largest and asymmetric welfare impacts for consumers and LTC holder mid-streamers. Price decreases favour consumers but hurt mid-streamers and EU producers and vice versa. The overall impact of these scenarios on storage and LNG regasification operators seems negligible.

Finally, Figure 61 illustrates that it is only the SP scenario again that could imply a visible change in the overall gas supply structure for the EU by first implying a demand increase as a response to a significant price decrease and then allowing gas sales of Russian origin to increase by 21.5% compared to the 2020 Reference, up to 2,165 TWh per year.

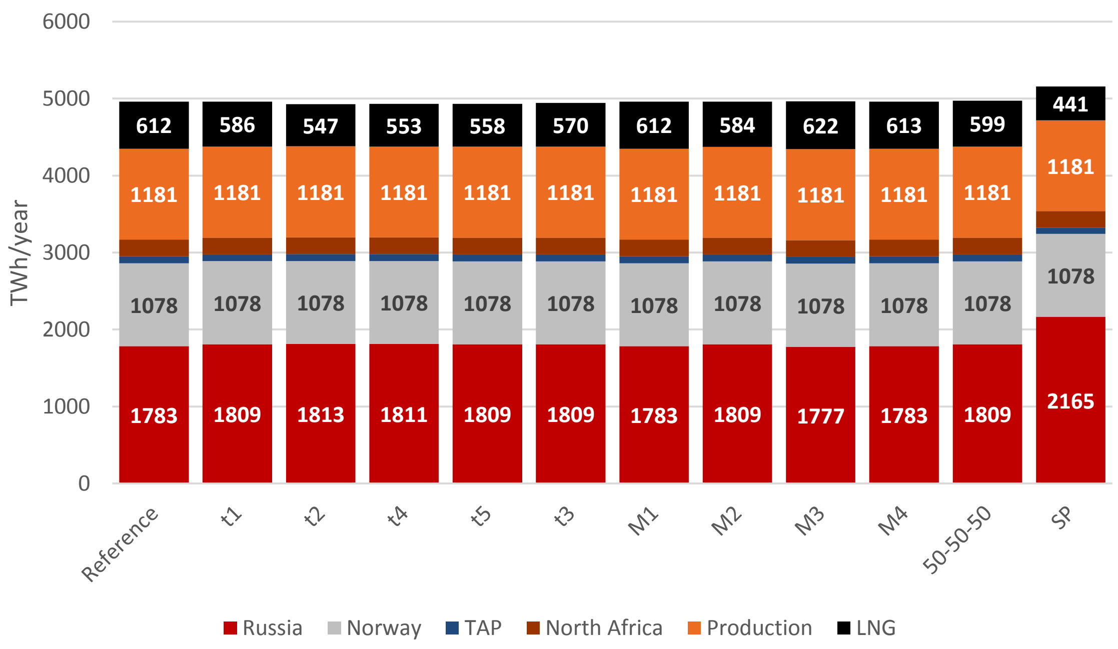

Figure 61: Gas supply structure to the EU in the base case regulatory scenarios (TWh/year)

7.2 Sensitivity analysis results

In this section we investigate the sensitivity of the welfare analysis of selected base case regulatory scenarios to some significant deviations of the 2020 gas market conditions from the assumed Reference. We consider five sensitivity scenarios, one with high demand, two with altered oil price and related LNG price (availability) assumptions and two versions of Nord Stream 2 implementation and operation.

7.2.1 The definition and welfare implications of sensitivity scenarios

We alter the 2020 Reference Scenario into the following sensitivity scenarios:

- **S1: High demand scenario.** In this case we assume a uniform 10% higher demand across the EU-28 Member States compared to the Reference.
- **S2a: LNG glut scenario.** In this scenario we assume LNG sales volumes to double on the European market. This might be due to LNG cost reduction, decreasing oil prices, etc. Dominant European suppliers react by reducing LTC prices and selling spot gas at lower prices, while keeping their market share and maximizing their profits.
- **S2b: LNG short scenario.** This is quite the opposite of the former scenario. LNG volumes sold to Europe drops significantly as LNG becomes more expensive. LTC and spot pipeline gas pricing adapts to this market situation so that incumbent suppliers are able to price their gas at a higher level.
- **S3a: Nord Stream 2A scenario.** This scenario assumes the implementation of the Nord Stream 2 pipeline into the 2020 Reference. In this scenario the use of Nord Stream 2 and the Brotherhood pipeline system is assumed to be complementary. Russian spot sales continue through Ukraine and Russia follows a profit maximizing strategy (see the related assumptions and discussion in Chapter 5)
- **S3b: Nord Stream 2B scenario.** This scenario also assumes the implementation of the Nord Stream 2 pipeline into the 2020 Reference but significantly alters the assumptions about the expected future use of the

Brotherhood pipeline system. In this scenario the use of Nord Stream 2 is strategic. Russia supplies only remaining LTC quantities but no spot volumes through Ukraine.

Table 47 summarises the changes that the different sensitivity cases bring about on prices and welfare compared to the 2020 reference case.

Sensitivity Scenario	Total welfare change, EURm/year	Consumer welfare change, EURm/year	Average wholesale price, EUR/MWh	Price divergence, %
S1	30,641	25,160	20.9 (+0.8)	10 (+3)
S2a	17,858	21,429	15.8 (-4.3)	13 (+6)
S2b	-31,504	-36,521	27.9 (+7.8)	10 (+3)
S3a	-41	4,923	19.1 (-1)	12 (+5)
S3b	-654	-256	20.1	16 (+9)

Table 47: Changes implied by sensitivity scenarios compared to 2020 Reference Scenario values (for prices the change compared to 2020 Reference is indicated in brackets)

We can make the following observations on the price and welfare implications of the sensitivity scenarios when compared to the 2020 Reference.

- Above-reference gas demand growth (S1) could boost EU welfare. The interplay of a shift of the demand curve to the right and a flexible supply situation results in a moderate price increase and boosts consumer surplus. Increased gas consumption seems strongly welfare improving under the expected 2020 demand/supply conditions.
- The LNG glut (S2a) scenario boosts EU welfare by pushing down the EU average wholesale price by more than 4 EUR/MWh, the strongest decrease among the sensitivity scenarios and an impact comparable to the Strategic Partnership Concept (see Figure 62). Growing price divergence, due to increased congestions in the West-East direction, is another key feature of this sensitivity. The latter result reflects the limited ability of some CSEE countries to benefit from an LNG glut under the 2020 infrastructure topology.

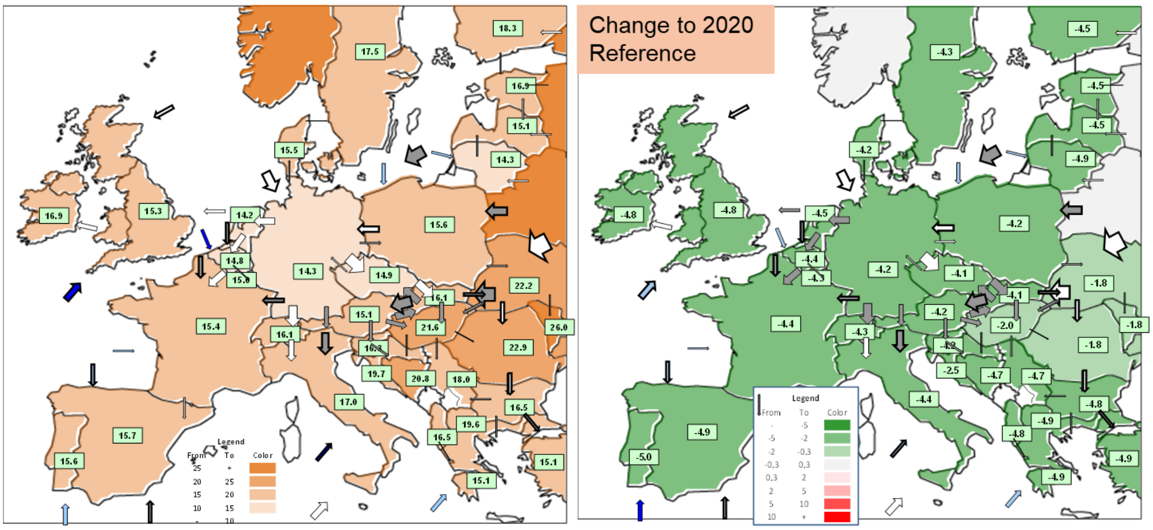

Figure 62: Wholesale prices in the LNG glut scenario (left) and wholesale price changes compared to the 2020 Reference case (right), EUR/MWh

- The S2b sensitivity scenario, assuming a higher opportunity cost of selling LNG to the EU market (e.g. due to higher oil prices or increased demand in emerging new LNG markets), hurts EU welfare the most. An oil price increase to 88 USD/barrel (doubling the Brent crude price of 2016) compared to the 2020

Reference implies a 65% increase in the opportunity cost of LNG to the EU market and a simultaneous increase in LTC prices in our simulation. The consequence is 39% gas wholesale price increase on the Reference. This unfavourable price impact happens to take place evenly across the EU and thus leaves the level of price divergence close to the 2020 Reference level.

- The most striking feature of the Nord Stream 2 sensitivity scenarios is that they double the level of price divergence on the IGM. Especially the case S3b, when Nord Stream 2 implementation results in the related re-routing of LTC quantities from Ukraine to Nord Stream 2 and a drastic reduction of gas sales through Ukraine creates a serious congestion and related price divergence between NW and CSEE Europe (see Figure 63).[163]

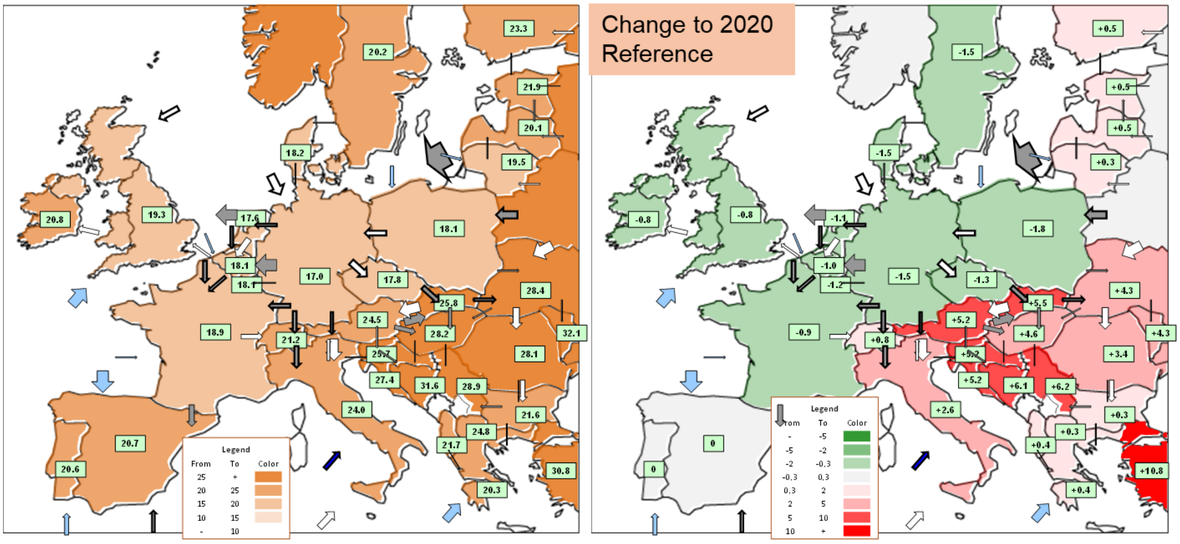

Figure 63: Wholesale prices in the Nord Stream 2B scenario (Russia supplies only remaining LTC quantities but no spot volumes through Ukraine) (left) and wholesale price changes compared to the 2020 Reference case (right), EUR/MWh

- The likely welfare impacts of the Nord Stream 2 sensitivities are mixed. While the total welfare impact of both Nord Stream 2 scenarios seems to be negative, EU consumers might benefit from a moderate EU wholesale price decrease in scenario S3a when Russia decides to utilize the Ukrainian route for spot trade besides Nord Stream 2. However, this benefit disappears immediately when Russia decides to manage Ukrainian transit in a more strategic manner. The most important implication of this finding is that the implementation of Nord Stream 2 enhances the room for manoeuvre for Russia to unilaterally deciding about its sales strategies for the different regions of the EU with significant related consumer welfare implications.

- We note that those sensitivities with location-specific impacts (LNG glut, Nord Stream 2) tend to significantly increase price divergence within the IGM by causing significant congestions at specific IPs. For example, the level of price

[163] This result confirms former REKK modelling results on the same topic. A similar paper by EWI (Dr. Harald Hecking and Florian Weiser (2017), *Impacts of Nord Stream 2 on the EU natural gas market*) found that overall welfare effects of the Nord Stream 2 project are highly positive from the point of view of European consumers, as the pipeline brings new gas source to the EU markets, which is more competitive than the LNG arriving to Europe. The reference case against which the effects were analysed assumed significantly lower trade via Ukraine, i.e. a state of the world with scarcity in gas supply for Europe.

Previous REKK modelling suggested overall negative effects of the Nord Stream 2 pipeline, resulting in an opening price gap between West and East. REKK modelling assumed a reference case where currently transited volumes via Ukraine remain unchanged, if Nord Stream 2 is not in place. See: Péter Kotek - Adrienn Selei - Borbála Takácsné Tóth (2017): *The effects of constructing Nord Stream 2 on the European natural gas prices and competition* (http://rekk.hu/downloads/academic_publications/NordStream2_REKK.pdf) divergence in the Nord Stream 2B scenario is eight times (!) higher than in any of the Tariff Reform Scenarios. These sensitivity scenarios can help detecting the vulnerabilities of the EU gas infrastructure hidden by the favourable market conditions typical by early 2018.

- By looking at the impact of the sensitivity scenarios on the gas supply structure of the EU (Figure 64) we see a moderate price responsiveness of demand, apparently aside from the demand sensitivity scenario (S1). It is only the LNG short / high oil price scenario (S2b) when a significant EU price increase results in a sizeable reduction of overall EU gas demand compared to the 2020 Reference case. It is also interesting to conclude on the likely development of pipeline – LNG competition to serve EU demand in the different cases. LNG supply grows in absolute terms in the increased demand (S1), LNG glut (S2a) and the strategic Nord Stream 2 (S3b) scenarios, while Russian gas supply increases the most in the first Nord Stream 2 scenario (S3a). It seems that LNG is the marginal source to meet additional EU gas demand (S1 and S2a) and can make up the missing spot volumes through Ukraine in the strategic Nord Stream 2 scenario.

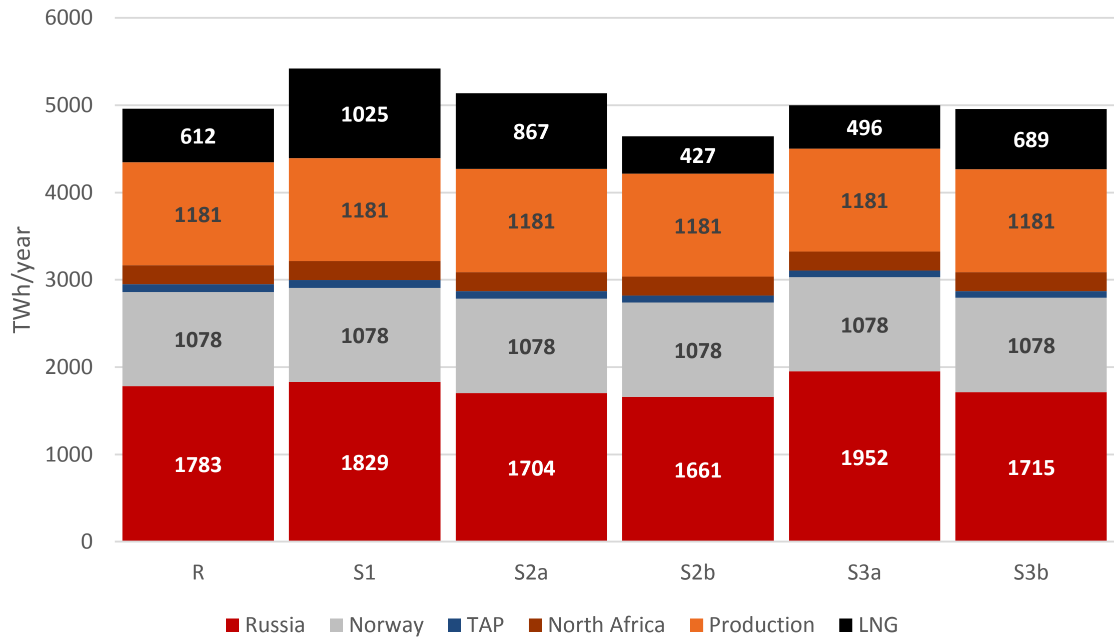

Figure 64: Gas supply structure to the EU in the sensitivity scenarios (TWh/year)

- Finally, jointly considering EU and Energy Community price and welfare impacts of the sensitivity scenarios does not change our former conclusions on these scenarios (see Table 47 above).

7.2.2 The performance of alternative regulatory scenarios under sensitivity scenario conditions

Our next question is how the regulatory scenarios, defined in Chapter 6 and modelled in Section 7.1 perform from a welfare point of view under the market conditions represented by the sensitivity scenarios, defined in Section 7.2. As we saw, the sensitivity scenarios already brought about very significant price and welfare changes when compared to the assumed 2020 Reference case. By interacting these sensitivities with the alternative regulatory scenarios we want to see to what extent those regulatory changes can mitigate or enhance the changes brought about by the investigated sensitivities.

For the sensitivity analyses of our regulatory scenarios we first selected the best performing Tariff Reform Scenario version (T1), the largest investigated Market Merger case (M2), the "50-50-50" and the Strategic Partnership Concepts. Next we “implemented” these regulatory scenarios under each sensitivity conditions. The price and welfare implications of the implementation of this selected set of regulatory scenarios under sensitivity conditions are presented in Table 48.

- By implying a fundamental structural change in the relation of the EU and its extra-EU suppliers, the Strategic Partnership Concept brings the largest price changes and welfare improvements both in the Reference and the sensitivity cases. It implies the largest total and consumer welfare improvement when combined with the high oil price (LNG short) and the non-strategic Nord Stream 2 (S3a) scenarios. However, as mentioned before, these impacts should be contrasted with changes in the profits of extra-EU suppliers when implementing the SP scenario that is beyond the scope of the present study.

Sensitivity vs Regulatory Scenarios	Total welfare change, EURm/year (EU28)				Consumer welfare change, EURm/year (EU28)				Average wholesale price, EUR/MWh				Price divergence, %			
	T1	M2	50-50-50	SP	T1	M2	50-50-50	SP	T1	M2	50-50-50	SP	T1	M2	50-50-50	SP
REF	1,185	219	616	13,319	68	-266	1,546	24,148	20,1	20.2	19.8	15.2	3%	8%	7%	20%
S1	862	174	462	9,194	353	-449	1,455	9,959	20.9	21.0	20.7	19.4	6%	10%	7%	21%
S2a	614	213	647	-664	131	636	1,971	7,589	15.7	15.6	15.4	13.6	9%	14%	10%	10%
S2b	241	85	708	38,873	5,401	1,498	3,118	56,092	26.7	27.6	27.2	15.1	11%	10%	11%	44%
S3a	1,124	134	-772	16,320	6,399	1,404	1,206	29,800	17.8	18.8	18.8	13.3	11%	12%	9%	22%
S3b	564	145	-432	7,788	1,628	313	562	-2,062	19.8	20.1	20.0	20.6	16%	16%	14%	34%

Table 48: Price and welfare implications of the implementation of a selected set of regulatory scenarios under sensitivity conditions for the EU

- From the more realistic set of regulatory scenarios for the different gas sources and thus improves market integration and price convergence at the cost of price increases in originally low priced zones. In the meantime the price impact of the “50-50-50” scenario is realized by increased liquidity and competition in originally high priced regions and thus can lead to lower prices in these regions without implying price increases in lower priced zones.

7.3 Discussion of regulatory scenario analyses results

Based on the results of the quantitative welfare analyses we carried out by EGMM for the proposed regulatory scenarios under 2020 Reference and sensitivity scenarios we draw the following conclusions.

(1) **To go ahead with the Tariff Reform Scenario would be a smart move** to enhance price convergence and insure against the risk of future gas market segmentation in the EU. Under the present and forecasted 2020 reference gas market conditions the implementation of a carefully designed tariff reform scenario could support further, welfare improving gas market integration within the EU even in the current low demand and low-price market environment. This is reflected by the almost complete wholesale price convergence these scenarios imply.

The typical pattern of Tariff Reform Scenario welfare impacts under expected 2020 reference market conditions is that they rather redistribute than increase welfare through increased cross-border trading. However, the implementation of the Tariff Reform Scenario turns highly beneficial when implemented under more turbulent sensitivity scenarios, which bring increased price divergence for the IGM. It performs especially well by producing more than EUR 5 billion annual consumer welfare increase when implemented in a high oil price – LNG short environment and when Nord Stream 2 is built, and Russia supplies only remaining LTC quantities but no spot volumes through Ukraine.

Further, the Tariff Reform Scenario could help the voluntary market merger process by removing one of the critical conflict issues from merger discussions: IP point and tariff removal and related inter-TSO compensation problems, since the TSO Compensation Fund would have already solved them.

The Tariff Reform Scenario could boost the competitive pressure LNG puts on pipeline gas suppliers in regions with no direct access to LNG. Moreover, a tariff reform could bring about additional welfare benefits, like increased short term market liquidity and more flexibility in cross-border balancing, that the EGMM cannot capture.

The performance of the Tariff Reform Scenario is sensitive to design issues. Its versions with additional tariffs on LNG entry points tend to immediately increase wholesale prices across the EU and as such are destructive for consumer welfare. Another complication of the proposed Tariff Reform Scenario is that it is to be complemented with a TSO Compensation Fund.

(2) **Market merger benefits are small but apparent.** The investigated market merger cases brought moderate EU welfare improvements in those cases when wholesale price differences were still present before the merger. The merger of the Spanish and Portuguese markets on the 2020 reference produced negligible price and welfare impacts because we expect the already moderate (below 0.5 EUR/MWh) 2016 wholesale price difference levelling off by 2020 due to increasing demand and LNG costs.

There are two major aspects of a merger scenario that can undermine the social benefits of the case: the additional cost of expanding the infrastructure for the merged zone (if needed) and the potential price increase in the countries neighbouring the merged zone due to the additional tariffs put on the zone's outside E/E points. We did not quantify the infrastructure related costs of the investigated merger cases, but we assume that it would be significant in the North-West and Baltic merger cases.

We found the second impact (increased prices in neighbouring countries) relevant in the North-West (DE-NL-BE-LU-CZ) merger case. This is a warning that while a bottom-up approach of smaller market mergers might be a politically easy and thus the feasible way towards gas market zones integration, this segmented process could lead to a set of market zones separated by high tariff barriers around the EU – a rather negative outcome.

We think that a Tariff Reform implementation could boost the voluntary market merger process by removing one of the critical conflict issues from merger discussions: IP point and tariff removal and related inter-TSO compensation problems.

(3) **The Combined Capacity-Commodity Release Scenario improves EU welfare in a robust and focused manner.** It improves EU consumer welfare by an annual EUR 1.5-3 billion across the different scenarios and results mostly in positive total welfare outcomes. The sources of welfare improvements are increasing product market competition in less liquid CSEE countries (commodity release) and improved efficiency in using the EU gas transmission infrastructure (capacity release).

There are two additional attractions of this scenario. It reduces prices and improves the welfare in relatively high price countries without implying a parallel price increase in low price countries. In addition, it requires only the modification of existing legislation (CAM NC) and the application of existing experiences with past gas release programs but no new institution (like a TCF) or major new regulation is a precondition for its application.

(4) **An extra-EU upstream and EU downstream Strategic Partnership might have the potential to bring EU gas wholesale prices close to internationally competitive levels.** This cooperative scenario could clearly reshape the upstream conditions for the EU IGM and provide very significant welfare gains for EU stakeholders, especially customers. However, this scenario is highly hypothetic and intends only to initiate further thinking and research into potential cooperative solutions for the EU gas markets' most important problem, which is high import dependence and simultaneous high market concentration.

With regard to the investigated sensitivity cases, our most important observations are as follows.

(5) **Gas market related total welfare is highly sensitive to demand and LNG supply shocks in the EU.** While higher than reference demand increase could boost gas consumption related EU welfare due to abundant and flexible supply conditions, EU welfare is highly sensitive to LNG supply conditions.

(6) **The most efficient non-cooperative solution to put competitive pressure on EU pipeline gas suppliers and improve EU welfare is to provide seamless access for LNG to the EU IGM.** Aside from the Strategic Partnership Concept, it was only in the LNG glut sensitivity scenario where we could simulate remarkable wholesale gas price decreases. An LNG glut in combination with a "50-50-50" regulatory scenario could reduce EU gas wholesale prices most. Tariff Reform Scenarios that increase LNG entry tariffs to the EU transmission grid are highly destructive for EU welfare.

(7) **Once it is built, the impact of Nord Stream 2 on EU consumers' welfare depends on the unilateral decision of Russia** how to use (or not to use) the

Ukrainian transit pipeline system. From the realistic regulatory scenarios the Tariff Reform Scenario seems to be the most effective remedy to relieve the sharp price divergence that Nord Stream 2 is expected to create between North-West and Central and South East Europe.

8. CONCLUSIONS AND RECOMMENDATIONS

By reviewing the current internal EU gas market regulatory framework, the Quo vadis study aims at assessing whether the market functioning alongside the overall EU welfare can be improved by revising the current framework. If so, the study objective is to propose regulatory changes which would lead to such an improved welfare. The study was based on own research and analyses, recently published papers and on regular consultations with the main stakeholders (EU and national governments representatives, NRAs, TSOs, SSOs, multiple gas industry organisations, producers, midstreamers, retail companies, traders and commodity exchange representatives).

8.1 Key market inefficiencies

We conclude that the functioning of the EU internal gas market has significantly improved with the introduction and continuous implementation of the Third Energy Package and related Network Codes. This conclusion has also been voiced by majority of the market participants during the stakeholder discussion process. Nevertheless, we have identified several market inefficiencies which, if remedied, could lead to further improved regulatory setup, gas market functioning and to improved EU welfare. The key inefficiencies are:

1. EU upstream market concentration

Based on our assessment, the key problem for the EU gas market development is its high (over 70% in 2016) and growing import dependence and the simultaneous high concentration in supplying its import needs. We have compared the EU and US gas prices and concluded that the price premium that EU wholesale customers have been paying over US prices in the last decade is mostly related to the EU gas upstream sector, including non-EU gas suppliers. Model simulations indicate that a stronger and more fundamental integration of the EU gas market with a competitive non-EU upstream sector, based on production and export liberalisation could potentially boost the international competitiveness of the EU gas market. If upstream market concentration remains at the current level, putting competitive pressure on dominant pipeline suppliers remains the key regulatory option to mitigate its negative consequences. LNG and inter-fuel competition by renewable resources have such a potential. We state that the debate about the level of efficiency in the operation of the internal gas market and the remaining potential to improve it is to be evaluated in this broader context.

2. Transmission tariff level and its structure

The currently applied entry-exit transmission tariff system leads to a tariff 'pancaking' effect (accumulation of tariffs to be paid by traders when shipping gas through several zone borders). We have identified the transmission tariff structure as one of the key barriers to an EU-wide integrated gas market. We have argued, that tariff pancaking hits new entrants to cross-border trading, limits the use of alternative gas transportation routes so that some routes may not be efficiently used and creates a barrier to developing more efficient cross-border balancing. These problems will become more visible as LTC capacity bookings start expiring from 2019. Moreover, neither the market merger process nor the TAR NC implementation process seem sufficient in addressing this issue.

3. Market foreclosure risk by long term capacity bookings

Long-term capacity bookings and physical delivery to the target country by extra-EU producers create inefficiencies in the redistribution of the contracted gas volumes according to short term supply – demand conditions within Europe. To mitigate the welfare loss caused by the limited tradability of the gas along the long term contracted route, capacity bookings on existing infrastructure should be largely confined to short term (yearly or shorter) products.

At the same time, we expect the appetite of extra-EU suppliers for long-term capacity bookings to remain intense and the related risk of market foreclosure apparent. The first large scale application of CAM NC on capacity auction with new capacities provided a stark example of potential market foreclosure by long-term capacity bookings by an extra-EU producer.

8.2 Reference scenario (2020)

The Reference Scenario simulates the expected gas market conditions in 2020. The EGMM model has been calibrated on 2016 gas market data and proved to reproduce the real data correctly. In comparison to the Status Quo, we have assumed in the Reference Scenario a full implementation of the Third Energy Package and commissioning of TYNDP FID infrastructure, except for the Nord Stream 2 project. Moreover, we have assumed that expiring LTCs are re-contracted at 30% of their annual contract quantity, using the same pricing mechanism (i.e., the contractual terms for pricing remain unchanged). We argue, that the main inefficiencies identified in the previous chapters – EU upstream market concentration and transmission tariff structure will prevail also in the Reference Scenario.

The EU upstream market concentration is not expected to change at the EU level with the full implementation of the Third Energy Package as these measures do not attempt to impact the EU import volume nor its structure. Hence, as indicated in the supply and demand outlook, along with a moderate 1.3% demand increase we expect EU import dependence to increase from 72% in 2016 to 76% 2020. In addition, on regional level, with full implementation the market access shall be liberalised by that time and enable import/supply competition that will change local market import structures.

After the TAR NC full implementation, the highest transmission tariff outliers are expected to be lowered (in the EGMM we have expected that the 15% of the highest tariffs are cut back). Nevertheless, the entry-exit tariff structure and therefore the related tariff 'pancaking' problem will prevail.

8.3 Alternative regulatory measures

As a result, the proposed regulatory measures were designed to mainly respond to the above-listed three inefficiencies which are expected to still be an issue in 2020. We have considered more than a dozen of alternative regulatory measures out of which the following have been identified as potentially the most beneficial from a welfare perspective, the most powerful in addressing the identified inefficiencies and therefore we have analysed these measures in greater detail:

- **Tariff Reform Scenario**: intra-EU cross-border tariffs will be set to zero which will lead to increased liquidity between the zones and therefore to higher price convergence across EU. The revenue shortfall for TSOs will be compensated by increasing either EU entry border tariffs or domestic exit tariffs (or a combination of both) and redistributing the revenues through a TCF mechanism.
- **Market Merger Scenario**: four potential market mergers based on potentially suitable network topology offering synergies have been investigated: (i) Spain – Portugal, (ii) Germany – Netherlands – Belgium – Luxembourg – Czech Republic, (iii) Romania – Bulgaria and (iv) Latvia – Lithuania – Estonia – Finland.
- **Conditional Market Merger Scenario**: several candidate zones have been identified with the aim to increase liquidity and to reduce location spreads between two neighbouring zones not connected by sufficient capacity to form a full market merger and usually consisting of a more developed main market and a less developed connected market. Transmission capacities within the zone will be initially priced at zero. Transmission tariff premium will be collected on occasions of temporary congestion, when demanded capacity will surpass the technically available capacity.
- **Combined Capacity-Commodity Release Scenario**: a simultaneous increase up to 50% in the share of short term transmission capacities for both existing

and new infrastructure and an obligation for gas producers/importers to sell at least 50% of their gas at the nearest VTP to their entry into the transmission grid on the EU territory.

- **Strategic Partnership Concept**: on the example of a strategic cooperation between EU and Russia, the issue of upstream market concentration is demonstrated and a cooperative solution evaluated.

To estimate the incremental economic welfare impact of implementing the alternative regulatory measures above, we have used the EGMM model. We have compared the price and welfare impact of these proposals to the Reference Scenario results. We have also tested the performance of the alternative regulatory scenarios under multiple sensitivities: (i) high demand, (ii) LNG glut, (iii) LNG short, (iv) Nord Stream 2 commissioning and (v) Nord Stream 2 commissioning where Russia is not supplying spot volumes through Ukraine.

8.4 Modelling results

As a result of modelling, based on both qualitative and quantitative analysis and assumptions, conditions and limitations presented in the study, we conclude that:

(1) **The Tariff Reform Scenario** recommends restructuring the point of collection of EUR 2-3 billion TSO revenues to further promote trade and market integration on the EUR 150 billion IGM. To go ahead with the Tariff Reform Scenario would be a smart move to enhance price convergence and insure against the risk of future gas market segmentation in the EU. Under the present and forecasted 2020 reference gas market conditions the implementation of a carefully designed tariff reform scenario could support further welfare improving gas market integration within the EU even in the current low demand and low-price market environment. This is reflected by the almost complete wholesale price convergence these scenarios imply.

The typical pattern of Tariff Reform Scenario welfare impacts under expected 2020 reference market conditions is that they rather redistribute than increase welfare through increased cross-border trading. However, the implementation of the Tariff Reform Scenario turns highly beneficial when implemented under more turbulent sensitivity scenarios, which bring increased price divergence for the IGM. It performs especially well by producing more than EUR 5 billion annual consumer welfare increase when implemented in a high oil price – LNG short environment and when Nord Stream 2 is built, and Russia supplies only remaining LTC quantities (but no spot volumes) through Ukraine.

Further, the Tariff Reform Scenario could help the voluntary market merger process by removing one of the critical conflict issues from merger discussions: IP point and tariff removal and related inter-TSO compensation problems, since the TSO Compensation Fund would have already solved them.

The Tariff Reform Scenario could boost the competitive pressure LNG puts on pipeline gas suppliers in regions with no direct access to LNG. Moreover, a tariff reform could bring about additional welfare benefits, like increased short-term market liquidity and more flexibility in cross-border balancing, that the EGMM cannot capture.

The performance of the Tariff Reform Scenario is sensitive to design issues. Its versions with additional tariffs on LNG entry points tend to immediately increase wholesale prices across the EU and as such are destructive for consumer welfare. Another complication of the proposed Tariff Reform Scenario is that it is to be complemented with a TSO Compensation Fund.

(2) The investigated **market merger cases** brought moderate EU welfare improvements in those cases when wholesale price differences were still present

before the merger. The merger of the Spanish and Portuguese markets on the 2020 reference produced negligible price and welfare impacts because we expect the already moderate (below 0.5 EUR/MWh) 2016 wholesale price difference levelling off by 2020 due to increasing demand and LNG costs.

There are two major aspects of a merger scenario that can undermine the social benefits of the case: the additional cost of expanding the infrastructure for the merged zone (if needed) and the potential price increase in the countries neighbouring the merged zone due to the additional tariffs put on the zone's outside entry/exit points. We did not quantify the infrastructure related costs of the investigated merger cases, but we assume that it would be significant in the North-West and Baltic merger cases.

We found the second impact (increased prices in neighbouring countries) relevant in the North-West (DE-NL-BE-LU-CZ) merger case. This is a warning that while a bottom-up approach of smaller market mergers might be politically easier and thus the more feasible way towards gas market zones integration, this segmented process could lead to a set of market zones separated by high tariff barriers around the EU – a rather negative outcome.

(3) **The Combined Capacity-Commodity Release Scenario** improves EU welfare and is a robust and focused measure. It improves EU consumer welfare by an annual EUR 1.5-3 billion across the different sensitivity scenarios and results mostly in a positive total welfare outcomes. The sources of welfare improvements are increasing product market competition in less liquid CSEE countries (commodity release) and improved efficiency in using the EU gas transmission infrastructure (capacity release).

There are two additional advantages of this scenario. It reduces prices and improves the welfare in relatively high price countries without implying a parallel price increase in low price countries. In addition, it requires only the modification of existing legislation (CAM NC) and the application of existing experiences with past gas release programs but no new institution (like a TCF) or major new regulation is a precondition for its application.

Therefore, we conclude that the implementation of this scenario is a no-regret policy and recommend going ahead with it.

(4) **An extra-EU upstream and EU downstream Strategic Partnership** might have the potential to significantly decrease EU gas wholesale prices. This cooperative concept could clearly reshape the upstream conditions for the EU IGM and, depending on the result of the related benefits sharing, it could provide significant welfare gains for EU stakeholders, especially customers.

However, this concept is highly hypothetic and intends only to initiate further thinking and research into potential cooperative solutions for the EU gas markets' most important problem that is high import dependence and simultaneous high market concentration.

During our qualitative analysis, we have already formulated certain expectations regarding the welfare increase by the proposed regulatory measures. Based on our initial qualitative assessment we have expected that the welfare increase of the modelled alternative regulatory cases will be higher, mainly due to increased liquidity and higher flexibility of the markets. The conservative quantitative results are mostly caused by the nature and limitations of the EGMM model- no short-term trading represented, perfect competition. EGMM also cannot simulate daily bidding and therefore there is no reliable measure of market liquidity. We assumed for example, that the Tariff Reform Scenario will ease cross-border balancing and is likely to improve market liquidity. Unfortunately, EGMM could not capture and quantify these positive impacts. The model's fundamental comparative static nature also puts a limit on simulating the outcomes of the investment incentives inherent for the regulatory scenarios.

Even under the above-mentioned modelling constraints and assuming a full implementation of the Third Package and a perfectly efficient utilization of the EU transmission grid by 2020 as if implicit capacity allocation was already fully implemented, the alternative regulatory scenarios produced considerable welfare improvements.

The Combined Capacity-Commodity Release Scenario turned out to improve EU welfare in the most robust and focused manner. It was estimated to improve EU consumer welfare by an annual EUR 1.5-3 billion across the different sensitivity scenarios and resulted mostly in positive total welfare outcomes. The sources of welfare improvements are increasing product market competition in less liquid CSEE countries (commodity release) and improved efficiency in using the EU gas transmission infrastructure (capacity release).

The Tariff Reform Scenario is able to further promote trade and market integration on the cc. EUR 100 billion IGM by simply restructuring the point of collection of EUR 2-3 billion TSO revenues. It performed very well in insuring against the (likely) risk of future gas market segmentation in the EU by producing more than EUR 5 billion annual consumer welfare increase when implemented in a high oil price – LNG short environment and when Nord Stream 2 is built, and Russia supplies only remaining LTC quantities but no spot volumes through Ukraine. In addition, the Tariff Reform Scenario could boost the competitive pressure LNG puts on pipeline gas suppliers in regions with no direct access to LNG. Moreover, a tariff reform could bring about additional welfare benefits, like increased short-term market liquidity and more flexibility in cross-border balancing, that the EGMM cannot capture.

8.5 Recommendations

Based on our analysis, we list below (i) the recommendations based on the results of this study and (ii) proposed next steps for further research. The analyses presented in this study support the following policy recommendations.

As general, the study has proved that some of the identified market inefficiencies can be remedied by an update of the current regulation, e.g. regarding increasing the share of the existing technical capacity set aside for short-term bookings. The modelling results have also demonstrated that the chosen alternative regulatory scenarios have the potential to increase EU welfare, most notably under specific sensitivity scenarios.

The main recommendations based on this study are:

- To amend paragraphs 6 and 7 of Article 8 of Regulation 2017/459 to increase the share of existing technical capacity that TSOs are obliged to set aside and offer for auctioning for yearly or shorter durations to 50% or more. The same approach of increasing the share of yearly or shorter durations from 10% to 50% should also be considered for incremental capacity within the EU to prevent future market foreclosure.
- To consider the full implementation of the Combined Capacity-Commodity Release Scenario. This would entail the amendment of Regulation 2017/459 as indicated in the former recommendation and the implementation of gas release programs for existing and future LTCs in the EU countries of entry for LTC commodity.
- To consider the implementation of the Tariff Reform Scenario after further refining the design and implementation conditions of it as presented in the study. Designs with add-on tariffs or harmonised tariffs differentiated by EU entry, EU

exit and domestic exit points as well as TCF implementation issues should further be considered.

- To include the concept of a potential Strategic Partnership – and the corresponding liberalization of the Russian gas sector – on the agenda of future EU-Russia energy dialogue and negotiation process on Nord Stream 2 or DG Competition cases with the objective to promote a competitive EU gas upstream sector.
- Further as more low-level measures to consider:
  - increasing the motivation for TSO cooperation and operational efficiency, with potential introduction of independent TSO operator and TSO benchmarking,
  - discussing and proposing of a guidance on local market mergers (e.g., best practice, escalation mechanisms, evaluation of impact on neighbouring zones),
  - pushing for higher harmonisation of national regulatory environments to create EU-wide transparency.

8.6 Next steps and further research

Based on the research and analyses we have performed and also based on the multiple discussions with and comments received from individual stakeholders, we have identified the following topics which are beyond the scope of the Quo vadis report, but we believe that these topics are worth further developing in future studies and projects:

- Testing alternative regulatory scenarios based on various assumptions related to Brexit options
- Further analysis of tariff reform scenarios with differentiated entry/exit fees
- Reflecting the situation of non-regulated TPA gas storage and their impact on the EU gas market
- Implementation and transition costs of individual alternative regulatory scenarios
- Comparison of EU and US recent gas market development, their main drivers, welfare and environmental impacts and stakeholders involved
- Potential of EU indigenous gas production and how its full utilisation might impact the gas market
- The role of infrastructure in the EU gas market: its further development design, investment incentives and the issue of potential stranded assets
- The impact of different gas supply and demand elasticities in the individual gas markets across EU on the welfare impacts of the alternative regulatory scenarios
- Likely impacts of proposed regulatory scenarios on Energy Community contracting parties
- The costs, benefits of and preconditions for unbundling of regasification terminals from any supply and trade functions
- The impact of CO_2 policies and the interrelationship with the evolution of the energy sector (including electricity, heat, etc.), including the impact of the composition of the gas because of a possible higher content of H_2, green gas and bio-methane, as well as other energy industry developments and challenges
- Technical analysis - changes in legislation governing the gas market could have far-reaching implications on the technical level, bidirectionality is a case in point

- Detailed legal analysis of the possibility of terminating or materially impacting the long-term capacity and/or commodity gas contracts by EU legislation by e.g., giving the parties the opportunity to withdraw from the binding agreement.

ANNEX 1: DETAILED MODELLING RESULTS

General remark to the tables in Annex 1: Figures in brackets in the 'TSO' columns represent TSO-related welfare impact without TCF use.

T1								
EURm/year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-56	7	12	270	0 (-510)	0	0	233
BE	-112	0	0	29	0 (133)	0	27	-56
BG	31	-1	2	-67	0 (-175)	0	0	-35
CZ	-83	2	8	72	0 (-210)	2	0	1
DE	-1,123	93	0	1,713	0 (794)	14	0	697
DK	-5	7	0	0	0 (-24)	0	0	2
EE	18	0	0	-7	0 (-20)	0	0	11
ES	-4	0	-1	5	0 (142)	0	-88	-88
FI	111	0	0	-82	0 (25)	0	0	29
FR	-44	0	25	-49	0 (106)	8	0	-60
GR	-3	0	0	26	0 (23)	0	42	65
HR	53	-32	0	0	0 (-17)	0	0	22
HU	280	-41	21	-86	0 (-88)	0	0	173
IE	97	-6	-1	0	0 (-53)	0	0	91
IT	654	-52	0	-450	0 (-308)	6	-27	130
LT	-2	0	0	2	0 (22)	0	9	9
LU	-8	0	0	0	0 (0)	0	0	-8
LV	0	0	0	0	0 (5)	1	0	1
NL	-437	486	0	215	0 (-92)	-6	0	258
PL	26	-6	0	-18	0 (308)	-6	0	-4
PT	1	0	0	0	0 (4)	0	10	11
RO	379	-263	-49	-19	0 (24)	0	0	48
SE	44	0	0	0	0 (-27)	0	0	44
SI	0	0	0	0	0 (-11)	0	0	0
SK	9	0	0	-40	0 (37)	0	0	-31
UK	240	-84	-19	-405	0 (-132)	-6	-41	-315
Total	**68**	**110**	**-3**	**1,106**	**0 (-43)**	**15**	**-68**	**1,228**

Table 49. Welfare change of T1 regulatory scenario by country and stakeholder in the reference case with TCF compensation

T2								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-141	18	12	576	0 (-520)	0	0	465
BE	-271	0	0	194	0 (140)	0	16	-60
BG	4	0	2	-23	0 (-176)	0	0	-17
CZ	-163	4	8	145	0 (-214)	2	0	-5
DE	-1,892	157	0	2,833	0 (623)	13	0	1,112
DK	-34	50	0	0	0 (-24)	0	0	15
EE	8	0	0	-3	0 (-21)	0	0	5
ES	-326	1	-1	257	0 (243)	0	-89	-158
FI	76	0	0	-57	0 (21)	0	0	20
FR	-445	0	25	282	0 (92)	8	0	-130
GR	-50	0	0	44	0 (77)	0	64	58
HR	27	-17	0	0	0 (-16)	2	0	13
HU	186	-28	22	-59	0 (-92)	0	0	120
IE	53	-3	-1	0	0 (-54)	0	0	49
IT	70	-6	0	-58	0 (-260)	6	-27	-16
LT	-28	0	0	25	0 (41)	0	9	6
LU	-19	0	0	0	0 (0)	0	0	-19
LV	-12	0	0	15	0 (3)	2	0	4
NL	-782	871	0	353	0 (-93)	-6	0	437
PL	-155	34	0	127	0 (285)	-6	0	0
PT	-42	0	0	22	0 (42)	0	1	-19
RO	268	-180	-46	-13	0 (-5)	0	0	30
SE	23	0	0	0	0 (-28)	0	0	23
SI	-7	0	0	1	0 (-13)	0	0	-6
SK	-45	1	0	32	0 (-84)	0	0	-13
UK	-479	213	-19	-180	0 (-39)	-7	-60	-533
Total	**-4,177**	**1115**	**3**	**4,513**	**0 (-74)**	**14**	**-86**	**1,382**

Table 50. Welfare change of T2 regulatory scenario by country and stakeholder in the reference case with TCF compensation

T3								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-134	11	12	539	0 (-476)	0	0	428
BE	-257	0	0	137	0 (108)	0	15	-105
BG	6	-1	2	-48	0 (-164)	0	0	-41
CZ	-157	3	8	100	0 (-169)	2	0	-44
DE	-1,827	118	0	2,379	0 (402)	13	0	682
DK	-32	23	0	0	0 (-9)	0	0	-8
EE	9	0	0	-5	0 (-18)	0	0	3
ES	-301	0	-1	120	0 (248)	0	-97	-279
FI	79	0	0	-71	0 (23)	0	0	8
FR	-411	0	25	116	0 (183)	8	0	-262
GR	-46	0	0	34	0 (8)	0	79	67
HR	30	-27	0	0	0 (-2)	2	0	5
HU	194	-36	22	-76	0 (-63)	0	0	104
IE	57	-5	-1	0	0 (-31)	0	0	51
IT	125	-38	0	-330	0 (11)	5	-27	-265
LT	-26	0	0	12	0 (32)	0	6	-8
LU	-18	0	0	0	0 (6)	0	0	-18
LV	-11	0	0	6	0 (0)	2	0	-3
NL	-753	635	0	318	0 (86)	-6	0	194
PL	-140	10	0	38	0 (126)	-6	0	-98
PT	-39	0	0	10	0 (42)	0	5	-24
RO	307	-268	-31	-19	0 (-45)	0	0	-12
SE	25	0	0	0	0 (-17)	0	0	25
SI	-7	0	0	0	0 (-9)	0	0	-6
SK	-41	0	0	-12	0 (-498)	0	0	-53
UK	-418	31	-19	-318	0 (198)	-7	-55	-787
Total	**-3,786**	**457**	**17**	**2,931**	**0 (-27)**	**13**	**-75**	**-443**

Table 51. Welfare change of T3 regulatory scenario by country and stakeholder in the reference case with TCF

T4								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-126	5	12	506	0 (-438)	0	0	398
BE	-243	0	0	88	0 (78)	0	14	-141
BG	8	-1	2	-68	0 (-154)	0	0	-59
CZ	-149	2	8	62	0 (-135)	2	0	-76
DE	-1,758	84	0	2,035	0 (198)	12	0	373
DK	-29	1	0	0	0 (4)	0	0	-28
EE	9	0	0	-7	0 (-16)	0	0	2
ES	-275	0	-1	3	0 (252)	0	-82	-355
FI	82	0	0	-83	0 (25)	0	0	-1
FR	-375	0	25	-27	0 (258)	8	0	-368
GR	-43	0	0	25	0 (-50)	0	57	40
HR	32	-35	0	0	0 (10)	2	0	-1
HU	203	-43	22	-90	0 (-39)	0	0	91
IE	61	-6	-1	0	0 (-12)	0	0	54
IT	183	-66	0	-562	0 (232)	5	-27	-467
LT	-24	0	0	2	0 (24)	0	9	-13
LU	-17	0	0	0	0 (10)	0	0	-17
LV	-10	0	0	0	0 (-2)	2	0	-9
NL	-722	432	0	270	0 (238)	-6	0	-26
PL	-123	-11	0	-38	0 (-14)	-6	0	-179
PT	-36	0	0	-1	0 (36)	0	4	-33
RO	343	-345	-18	-25	0 (-82)	0	0	-45
SE	27	0	0	0	0 (-7)	0	0	27
SI	-6	0	0	0	0 (-5)	0	0	-6
SK	-36	0	0	-50	0 (-854)	0	0	-86
UK	-354	-125	-19	-436	0 (385)	-7	-51	-992
Total	**-3,378**	**-108**	**30**	**1,603**	**0 (-58)**	**13**	**-76**	**-1,916**

Table 52. Welfare change of T4 regulatory scenario by country and stakeholder in the reference case with TCF

T5								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-94	6	12	398	0 (-463)	0	0	322
BE	-184	0	0	59	0 (103)	0	15	-111
BG	17	-1	2	-67	0 (-163)	0	0	-48
CZ	-120	2	8	65	0 (-164)	2	0	-43
DE	-1,473	86	0	1,853	0 (460)	10	0	477
DK	-18	2	0	0	0 (-8)	0	0	-16
EE	13	0	0	-7	0 (-18)	0	0	6
ES	-162	0	-1	4	0 (207)	0	-90	-249
FI	94	0	0	-82	0 (25)	0	0	12
FR	-226	0	25	-44	0 (197)	8	0	-237
GR	-26	0	0	26	0 (-18)	0	75	74
HR	41	-34	0	0	0 (-1)	2	0	9
HU	237	-42	21	-89	0 (-58)	0	0	126
IE	77	-6	-1	0	0 (-29)	0	0	70
IT	356	-58	0	-499	0 (11)	5	-27	-222
LT	-15	0	0	2	0 (23)	0	7	-6
LU	-13	0	0	0	0 (6)	0	0	-13
LV	-6	0	0	0	0 (1)	1	0	-4
NL	-594	446	0	244	0 (99)	-6	0	90
PL	-57	-10	0	-33	0 (126)	-6	0	-106
PT	-20	0	0	-1	0 (24)	0	9	-12
RO	361	-313	-32	-22	0 (-35)	0	0	-6
SE	35	0	0	0	0 (-16)	0	0	35
SI	-3	0	0	0	0 (-7)	0	0	-4
SK	-16	0	0	-48	0 (-474)	0	0	-64
UK	-87	-115	-19	-428	0 (171)	-6	-44	-700
Total	**-1,882**	**-36**	**15**	**1,329**	**0 (-3)**	**11**	**-57**	**-620**

Table 53. Welfare change of T5 regulatory scenario by country and stakeholder in the reference case with TCF

TH1								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-56	7	12	300	0 (-509)	0	0	264
BE	-113	0	0	-60	0 (193)	0	27	-146
BG	31	-1	2	-67	0 (-175)	0	0	-35
CZ	-83	2	8	72	0 (-212)	2	0	1
DE	-1,126	93	0	1,658	0 (885)	29	0	654
DK	-5	7	0	0	0 (-25)	0	0	2
EE	18	0	0	-7	0 (-22)	0	0	11
ES	-4	0	-1	5	0 (148)	0	-88	-88
FI	111	0	0	-82	0 (12)	0	0	29
FR	-46	0	25	-155	0 (77)	8	0	-168
GR	-3	0	0	26	0 (-7)	0	67	90
HR	53	-32	0	0	0 (-17)	0	0	22
HU	279	-41	21	-86	0 (-97)	0	0	173
IE	98	-6	-1	0	0 (-54)	-1	0	90
IT	651	-52	0	-448	0 (-343)	6	-27	129
LT	-2	0	0	2	0 (31)	0	-1	0
LU	-8	0	0	0	0 (0)	0	0	-8
LV	0	0	0	0	0 (7)	1	0	1
NL	-438	487	0	81	0 (-89)	-6	0	125
PL	25	-5	0	-17	0 (385)	-6	0	-4
PT	1	0	0	0	0 (4)	0	10	11
RO	381	-266	-48	-19	0 (15)	0	0	49
SE	44	0	0	0	0 (-27)	0	0	44
SI	0	0	0	0	0 (-11)	0	0	0
SK	9	0	0	-40	0 (-64)	0	0	-31
UK	256	-89	-19	-84	0 (-57)	-20	-41	3
Total	**74**	**105**	**-2**	**1,078**	**0 (47)**	**15**	**-53**	**1,217**

Table 54. Welfare change of TH1 regulatory scenario by country and stakeholder in the reference case with TCF

TH2								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-175	22	12	720	0 (-519)	0	0	580
BE	-333	0	0	151	0 (217)	0	12	-170
BG	-7	0	2	-6	0 (-176)	0	0	-11
CZ	-195	5	8	174	0 (-211)	2	0	-7
DE	-2,195	183	0	3,157	0 (694)	29	0	1,174
DK	-46	66	0	0	0 (-24)	0	0	21
EE	3	0	0	-1	0 (-23)	0	0	2
ES	-311	1	-1	246	0 (233)	0	-80	-146
FI	61	0	0	-46	0 (7)	0	0	16
FR	-604	1	25	311	0 (82)	8	0	-259
GR	-68	0	0	52	0 (70)	0	53	37
HR	17	-10	0	0	0 (-16)	2	0	9
HU	148	-23	22	-48	0 (-104)	0	0	99
IE	37	-2	-1	0	0 (-55)	-1	0	33
IT	-199	16	0	123	0 (-286)	6	-27	-81
LT	-40	0	0	35	0 (60)	0	-7	-12
LU	-23	0	0	0	0 (0)	0	0	-23
LV	-17	0	0	21	0 (4)	2	0	6
NL	-919	1024	0	209	0 (-87)	-6	0	309
PL	-226	50	0	184	0 (329)	-6	0	2
PT	-40	0	0	21	0 (47)	0	8	-11
RO	225	-148	-43	-11	0 (-20)	0	0	23
SE	15	0	0	0	0 (-28)	0	0	15
SI	-10	0	0	1	0 (-12)	0	0	-9
SK	-67	1	0	61	0 (-205)	0	0	-5
UK	-744	324	-19	350	0 (29)	-20	-69	-177
Total	**-5,713**	**1510**	**4**	**5,704**	**0 (5)**	**17**	**-110**	**1,411**

Table 55. Welfare change of TH2 regulatory scenario by country and stakeholder in the reference case with TCF

TH3								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-189	16	12	692	0 (-457)	0	0	532
BE	-404	0	0	100	0 (273)	0	14	-291
BG	-11	0	2	-29	0 (-159)	0	0	-39
CZ	-251	4	8	132	0 (-107)	2	0	-106
DE	-2,187	146	0	2,783	0 (543)	29	0	771
DK	-40	42	0	0	0 (-13)	0	0	2
EE	14	0	0	-3	0 (-31)	0	0	10
ES	-501	0	-1	111	0 (449)	0	-82	-472
FI	123	0	0	-59	0 (-51)	0	0	65
FR	-664	0	25	127	0 (256)	8	0	-504
GR	8	0	0	42	0 (-63)	0	39	89
HR	23	-19	0	0	0 (-7)	2	0	6
HU	136	-30	22	-64	0 (-57)	0	0	64
IE	122	-4	-1	0	0 (-114)	-1	0	117
IT	-48	-14	0	-133	0 (-135)	6	-27	-217
LT	-15	0	0	24	0 (29)	0	2	10
LU	-12	0	0	0	0 (-6)	0	0	-12
LV	-22	0	0	13	0 (6)	1	0	-7
NL	-1,043	804	0	147	0 (233)	-6	0	-98
PL	-169	27	0	101	0 (122)	-6	0	-46
PT	-5	0	0	9	0 (13)	0	11	15
RO	396	-232	-29	-17	0 (-194)	0	0	118
SE	74	0	0	0	0 (-74)	0	0	74
SI	7	0	0	1	0 (-25)	0	0	8
SK	-80	1	0	19	0 (-601)	0	0	-60
UK	-637	155	-19	245	0 (143)	-20	-67	-343
Total	**-5,375**	**894**	**19**	**4,242**	**0 (-24)**	**16**	**-109**	**-313**

Table 56. Welfare change of TH3 regulatory scenario by country and stakeholder in the reference case with TCF

TH4								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-147	5	12	506	0 (-415)	0	0	377
BE	-327	0	0	88	0 (161)	0	15	-225
BG	1	-1	2	-68	0 (-148)	0	0	-66
CZ	-212	2	8	62	0 (-72)	2	0	-139
DE	-1,812	84	0	2,035	0 (255)	12	0	319
DK	-26	1	0	0	0 (1)	0	0	-24
EE	19	0	0	-7	0 (-26)	0	0	12
ES	-498	0	-1	3	0 (471)	0	-79	-575
FI	141	0	0	-82	0 (-34)	0	0	59
FR	-469	0	25	-27	0 (351)	8	0	-463
GR	29	0	0	26	0 (-121)	0	68	123
HR	36	-35	0	0	0 (6)	2	0	4
HU	183	-43	22	-90	0 (-20)	0	0	71
IE	143	-6	-1	0	0 (-92)	0	0	136
IT	270	-65	0	-558	0 (140)	5	-27	-375
LT	-1	0	0	2	0 (1)	0	-5	-4
LU	-6	0	0	0	0 (0)	0	0	-6
LV	-16	0	0	0	0 (3)	1	0	-15
NL	-875	432	0	269	0 (391)	-6	0	-180
PL	-80	-11	0	-38	0 (-56)	-6	0	-136
PT	-5	0	0	-1	0 (7)	0	5	-1
RO	475	-344	-18	-25	0 (-212)	0	0	88
SE	85	0	0	0	0 (-64)	0	0	85
SI	11	0	0	0	0 (-21)	0	0	10
SK	-53	0	0	-50	0 (-835)	0	0	-104
UK	-305	-125	-19	-436	0 (337)	-7	-52	-944
Total	**-3,440**	**-107**	**30**	**1,608**	**0 (6)**	**13**	**-76**	**-1,972**

Table 57. Welfare change of TH4 regulatory scenario by country and stakeholder in the reference case with TCF

TH5								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-115	6	12	435	0 (-443)	0	0	338
BE	-269	0	0	-52	0 (249)	0	16	-305
BG	11	-1	2	-67	0 (-157)	0	0	-54
CZ	-183	2	8	66	0 (-108)	2	0	-105
DE	-1,528	88	0	1,817	0 (626)	25	0	402
DK	-15	3	0	0	0 (-12)	0	0	-11
EE	23	0	0	-7	0 (-30)	0	0	16
ES	-378	0	-1	4	0 (426)	0	-102	-477
FI	154	0	0	-82	0 (-48)	0	0	72
FR	-321	0	25	-108	0 (297)	8	0	-396
GR	47	0	0	26	0 (-120)	0	80	153
HR	45	-33	0	0	0 (-7)	1	0	13
HU	218	-42	22	-89	0 (-51)	0	0	109
IE	160	-6	-1	0	0 (-112)	-1	0	152
IT	448	-57	0	-487	0 (-133)	5	-27	-117
LT	9	0	0	2	0 (9)	0	-2	9
LU	-2	0	0	0	0 (-5)	0	0	-2
LV	-12	0	0	0	0 (8)	1	0	-10
NL	-748	455	0	96	0 (248)	-6	0	-202
PL	-13	-9	0	-30	0 (153)	-6	0	-58
PT	11	0	0	-1	0 (-7)	0	9	19
RO	497	-313	-30	-22	0 (-179)	0	0	131
SE	93	0	0	0	0 (-73)	0	0	93
SI	13	0	0	0	0 (-23)	0	0	13
SK	-33	0	0	-46	0 (-563)	0	0	-80
UK	-19	-114	-19	-94	0 (81)	-20	-44	-310
Total	**-1,905**	**-22**	**18**	**1,362**	**0 (26)**	**11**	**-71**	**-607**

Table 58. Welfare change of TH5 regulatory scenario by country and stakeholder in the reference case with TCF

EUR m/year change	T1	T2	T3	T4	T5	TH1	TH2	TH3	TH4	TH5
AT	0 (-510)	0 (-520)	0 (-476)	0 (-438)	0 (-463)	0 (-509)	0 (-519)	0 (-457)	0 (-415)	0 (-443)
BE	0 (133)	0 (140)	0 (108)	0 (78)	0 (103)	0 (193)	0 (217)	0 (273)	0 (161)	0 (249)
BG	0 (-175)	0 (-176)	0 (-164)	0 (-154)	0 (-163)	0 (-175)	0 (-176)	0 (-159)	0 (-148)	0 (-157)
CZ	0 (-210)	0 (-214)	0 (-169)	0 (-135)	0 (-164)	0 (-212)	0 (-211)	0 (-107)	0 (-72)	0 (-108)
DE	0 (794)	0 (623)	0 (402)	0 (198)	0 (460)	0 (885)	0 (694)	0 (543)	0 (255)	0 (626)
DK	0 (-24)	0 (-24)	0 (-9)	0 (4)	0 (-8)	0 (-25)	0 (-24)	0 (-13)	0 (1)	0 (-12)
EE	0 (-20)	0 (-21)	0 (-18)	0 (-16)	0 (-18)	0 (-22)	0 (-23)	0 (-31)	0 (-26)	0 (-30)
ES	0 (142)	0 (243)	0 (248)	0 (252)	0 (207)	0 (148)	0 (233)	0 (449)	0 (471)	0 (426)
FI	0 (25)	0 (21)	0 (23)	0 (25)	0 (25)	0 (12)	0 (7)	0 (-51)	0 (-34)	0 (-48)
FR	0 (106)	0 (92)	0 (183)	0 (258)	0 (197)	0 (77)	0 (82)	0 (256)	0 (351)	0 (297)
GR	0 (23)	0 (77)	0 (8)	0 (-50)	0 (-18)	0 (-7)	0 (70)	0 (-63)	0 (-121)	0 (-120)
HR	0 (-17)	0 (-16)	0 (-2)	0 (10)	0 (-1)	0 (-17)	0 (-16)	0 (-7)	0 (6)	0 (-7)
HU	0 (-88)	0 (-92)	0 (-63)	0 (-39)	0 (-58)	0 (-97)	0 (-104)	0 (-57)	0 (-20)	0 (-51)
IE	0 (-53)	0 (-54)	0 (-31)	0 (-12)	0 (-29)	0 (-54)	0 (-55)	0 (-114)	0 (-92)	0 (-112)
IT	0 (-308)	0 (-260)	0 (11)	0 (232)	0 (11)	0 (-343)	0 (-286)	0 (-135)	0 (140)	0 (-133)
LT	0 (22)	0 (41)	0 (32)	0 (24)	0 (23)	0 (31)	0 (60)	0 (29)	0 (1)	0 (9)
LU	0 (0)	0 (0)	0 (6)	0 (10)	0 (6)	0 (0)	0 (0)	0 (-6)	0 (0)	0 (-5)
LV	0 (5)	0 (3)	0 (0)	0 (-2)	0 (1)	0 (7)	0 (4)	0 (6)	0 (3)	0 (8)
NL	0 (-92)	0 (-93)	0 (86)	0 (238)	0 (99)	0 (-89)	0 (-87)	0 (233)	0 (391)	0 (248)
PL	0 (308)	0 (285)	0 (126)	0 (-14)	0 (126)	0 (385)	0 (329)	0 (122)	0 (-56)	0 (153)
PT	0 (4)	0 (42)	0 (42)	0 (36)	0 (24)	0 (4)	0 (47)	0 (13)	0 (7)	0 (-7)
RO	0 (24)	0 (-5)	0 (-45)	0 (-82)	0 (-35)	0 (15)	0 (-20)	0 (-194)	0 (-212)	0 (-179)
SE	0 (-27)	0 (-28)	0 (-17)	0 (-7)	0 (-16)	0 (-27)	0 (-28)	0 (-74)	0 (-64)	0 (-73)
SI	0 (-11)	0 (-13)	0 (-9)	0 (-5)	0 (-7)	0 (-11)	0 (-12)	0 (-25)	0 (-21)	0 (-23)
SK	0 (37)	0 (-84)	0 (-498)	0 (-854)	0 (-474)	0 (-64)	0 (-205)	0 (-601)	0 (-835)	0 (-563)
UK	0 (-132)	0 (-39)	0 (198)	0 (385)	0 (171)	0 (-57)	0 (29)	0 (143)	0 (337)	0 (81)
Total	**0 (-43)**	**0 (-74)**	**0 (-27)**	**0 (-58)**	**0 (-3)**	**0 (47)**	**0 (5)**	**0 (-24)**	**0 (6)**	**0 (26)**

Table 59. TSO revenue effects of regulatory scenarios in the reference case

T1								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-10	1	3	155	0 (-320)	0	0	149
BE	-64	0	0	-16	0 (105)	0	110	29
BG	40	-1	2	-71	0 (-177)	0	0	-31
CZ	-44	1	2	35	0 (-248)	0	0	-6
DE	-897	68	9	1,367	0 (644)	29	0	575
DK	7	-10	0	0	0 (-28)	0	0	-2
EE	27	0	0	-10	0 (-27)	0	0	17
ES	4	0	0	-3	0 (115)	0	-60	-58
FI	144	0	0	-97	0 (21)	0	0	47
FR	108	0	21	-156	0 (64)	0	-10	-37
GR	-3	0	0	13	0 (19)	0	17	26
HR	76	-44	5	0	0 (-31)	1	0	38
HU	274	-28	-79	-56	0 (-39)	2	0	112
IE	99	-5	-1	0	0 (-59)	0	0	93
IT	126	-10	20	-95	0 (-195)	0	-154	-114
LT	-2	0	0	1	0 (16)	0	31	31
LU	-4	0	0	0	0 (0)	0	0	-4
LV	7	0	0	-8	0 (-5)	0	0	-1
NL	-365	371	0	72	0 (-53)	0	44	122
PL	108	-22	0	-79	0 (260)	5	0	12
PT	0	0	0	0	0 (13)	0	26	26
RO	493	-327	-52	-23	0 (0)	0	0	90
SE	58	0	0	0	0 (-30)	0	0	58
SI	-11	0	0	1	0 (-10)	0	0	-10
SK	43	-1	0	-79	0 (-80)	0	0	-37
UK	140	-38	-20	-227	0 (-9)	0	-63	-209
Total	**353**	**-47**	**-91**	**723**	**0 (-54)**	**37**	**-60**	**916**

Table 60. Welfare change of T1 regulatory scenario by country and stakeholder in the high demand case with TCF

T2								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-102	12	1	459	0 (-339)	0	0	370
BE	-234	0	-1	148	0 (207)	0	110	23
BG	15	0	1	-34	0 (-180)	0	0	-19
CZ	-130	3	0	107	0 (-255)	0	0	-20
DE	-1,721	131	0	2,475	0 (459)	28	0	913
DK	-24	32	0	0	0 (-28)	0	0	8
EE	18	0	0	-6	0 (-28)	0	0	11
ES	-313	1	0	223	0 (202)	0	-70	-159
FI	113	0	0	-76	0 (16)	0	0	37
FR	-320	0	16	172	0 (72)	0	18	-114
GR	-47	0	0	28	0 (83)	0	27	8
HR	64	-36	2	0	0 (-36)	1	0	31
HU	268	-28	-76	-55	0 (-83)	2	0	110
IE	51	-3	-1	0	0 (-60)	0	0	48
IT	-601	43	18	357	0 (-105)	0	-169	-352
LT	-26	0	0	21	0 (39)	0	10	4
LU	-16	0	0	0	0 (-1)	0	0	-16
LV	-3	0	0	3	0 (-8)	0	0	1
NL	-737	748	0	211	0 (-29)	0	35	257
PL	-86	17	0	64	0 (215)	-3	0	-8
PT	-42	0	0	21	0 (74)	0	25	3
RO	492	-329	-48	-23	0 (-31)	0	0	91
SE	35	0	0	0	0 (-30)	0	0	35
SI	-14	0	0	2	0 (-20)	0	0	-13
SK	-15	0	0	-8	0 (-281)	0	0	-23
UK	-637	256	-21	-4	0 (233)	0	-93	-499
Total	**-4,014**	**847**	**-110**	**4,084**	**0 (86)**	**29**	**-107**	**729**

Table 61. Welfare change of T2 regulatory scenario by country and stakeholder in the high demand case with TCF

T3								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-91	6	1	424	0 (-293)	0	0	340
BE	-215	0	-1	95	0 (126)	0	112	-9
BG	17	-1	1	-55	0 (-168)	0	0	-37
CZ	-120	2	1	66	0 (-211)	0	0	-52
DE	-1,628	95	3	2,045	0 (266)	29	0	544
DK	-21	8	0	0	0 (-14)	0	0	-12
EE	18	0	0	-8	0 (-26)	0	0	10
ES	-278	0	0	98	0 (207)	0	-73	-253
FI	114	0	0	-87	0 (19)	0	0	27
FR	-272	0	18	19	0 (148)	0	19	-217
GR	-43	0	0	19	0 (13)	0	15	-9
HR	61	-42	3	0	0 (-24)	1	0	23
HU	255	-34	-60	-68	0 (-49)	2	0	95
IE	57	-4	-1	0	0 (-38)	0	0	51
IT	-522	13	19	106	0 (127)	0	-167	-550
LT	-24	0	0	10	0 (28)	0	21	7
LU	-14	0	0	0	0 (5)	0	0	-14
LV	-3	0	0	-3	0 (-9)	0	0	-5
NL	-695	531	0	188	0 (126)	0	35	59
PL	-64	-5	0	-17	0 (73)	-3	0	-90
PT	-38	0	0	9	0 (59)	0	26	-3
RO	485	-375	-33	-27	0 (-69)	0	0	50
SE	37	0	0	0	0 (-20)	0	0	37
SI	-15	0	0	1	0 (-13)	0	0	-14
SK	-8	0	0	-49	0 (-636)	0	0	-57
UK	-550	88	-20	-131	0 (365)	0	-91	-704
Total	**-3,557**	**282**	**-70**	**2,636**	**0 (-4)**	**29**	**-104**	**-784**

Table 62. Welfare change of T3 regulatory scenario by country and stakeholder in the high demand case with TCF

T4								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-86	1	2	400	0 (-255)	0	0	318
BE	-204	0	-1	55	0 (64)	0	106	-44
BG	18	-1	2	-71	0 (-158)	0	0	-53
CZ	-115	1	1	34	0 (-179)	0	0	-79
DE	-1,577	67	7	1,827	0 (119)	29	0	352
DK	-19	-11	0	0	0 (-2)	0	0	-29
EE	18	0	0	-10	0 (-23)	0	0	9
ES	-252	0	0	-4	0 (220)	0	-62	-317
FI	115	0	0	-97	0 (21)	0	0	19
FR	-246	0	20	-100	0 (209)	0	-14	-340
GR	-40	0	0	13	0 (-43)	0	7	-21
HR	57	-47	4	0	0 (-13)	1	0	16
HU	240	-39	-45	-78	0 (-19)	1	0	80
IE	60	-5	-1	0	0 (-20)	0	0	54
IT	-467	-10	20	-95	0 (319)	0	-165	-718
LT	-23	0	0	1	0 (19)	0	4	-17
LU	-14	0	0	0	0 (10)	0	0	-14
LV	-2	0	0	-8	0 (-11)	0	0	-10
NL	-671	365	0	89	0 (255)	0	38	-179
PL	-52	-22	0	-81	0 (-31)	3	0	-152
PT	-34	0	0	0	0 (47)	0	26	-9
RO	473	-408	-21	-29	0 (-97)	0	0	15
SE	39	0	0	0	0 (-11)	0	0	39
SI	-16	0	0	1	0 (-6)	0	0	-16
SK	-5	-1	0	-80	0 (-915)	0	0	-86
UK	-499	-43	-20	-230	0 (479)	0	-75	-867
Total	**-3,299**	**-153**	**-32**	**1,536**	**0 (-22)**	**35**	**-136**	**-2,049**

Table 63. Welfare change of T4 regulatory scenario by country and stakeholder in the high demand case with TCF

T5								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-54	1	2	299	0 (-281)	0	0	248
BE	-146	0	0	26	0 (78)	0	106	-15
BG	27	-1	2	-71	0 (-166)	0	0	-44
CZ	-86	1	1	34	0 (-206)	0	0	-49
DE	-1,295	67	7	1,502	0 (335)	29	0	309
DK	-8	-10	0	0	0 (-12)	0	0	-18
EE	22	0	0	-10	0 (-25)	0	0	12
ES	-147	0	0	-4	0 (177)	0	-61	-211
FI	127	0	0	-97	0 (21)	0	0	30
FR	-99	0	20	-124	0 (150)	0	-10	-213
GR	-25	0	0	13	0 (-18)	0	9	-3
HR	65	-46	5	0	0 (-20)	1	0	25
HU	252	-34	-61	-68	0 (-26)	2	0	91
IE	76	-5	-1	0	0 (-36)	0	0	70
IT	-224	-10	20	-95	0 (109)	0	-161	-470
LT	-14	0	0	1	0 (17)	0	14	1
LU	-10	0	0	0	0 (5)	0	0	-10
LV	2	0	0	-8	0 (-8)	0	0	-6
NL	-545	367	0	198	0 (125)	0	38	59
PL	14	-22	0	-81	0 (88)	3	0	-85
PT	-20	0	0	0	0 (33)	0	26	6
RO	481	-375	-34	-27	0 (-58)	0	0	46
SE	47	0	0	0	0 (-19)	0	0	47
SI	-14	0	0	1	0 (-8)	0	0	-13
SK	15	-1	0	-80	0 (-573)	0	0	-66
UK	-236	-41	-20	-229	0 (279)	0	-70	-596
Total	**-1,795**	**-110**	**-60**	**1,181**	**0 (-37)**	**36**	**-108**	**-857**

Table 64. Welfare change of T5 regulatory scenario by country and stakeholder in the high demand case with TCF

EURm/year change	T1	T2	T3	T4	T5
AT	0 (-320)	0 (-339)	0 (-293)	0 (-255)	0 (-281)
BE	0 (105)	0 (207)	0 (126)	0 (64)	0 (78)
BG	0 (-177)	0 (-180)	0 (-168)	0 (-158)	0 (-166)
CZ	0 (-248)	0 (-255)	0 (-211)	0 (-179)	0 (-206)
DE	0 (644)	0 (459)	0 (266)	0 (119)	0 (335)
DK	0 (-28)	0 (-28)	0 (-14)	0 (-2)	0 (-12)
EE	0 (-27)	0 (-28)	0 (-26)	0 (-23)	0 (-25)
ES	0 (115)	0 (202)	0 (207)	0 (220)	0 (177)
FI	0 (21)	0 (16)	0 (19)	0 (21)	0 (21)
FR	0 (64)	0 (72)	0 (148)	0 (209)	0 (150)
GR	0 (19)	0 (83)	0 (13)	0 (-43)	0 (-18)
HR	0 (-31)	0 (-36)	0 (-24)	0 (-13)	0 (-20)
HU	0 (-39)	0 (-83)	0 (-49)	0 (-19)	0 (-26)
IE	0 (-59)	0 (-60)	0 (-38)	0 (-20)	0 (-36)
IT	0 (-195)	0 (-105)	0 (127)	0 (319)	0 (109)
LT	0 (16)	0 (39)	0 (28)	0 (19)	0 (17)
LU	0 (0)	0 (-1)	0 (5)	0 (10)	0 (5)
LV	0 (-5)	0 (-8)	0 (-9)	0 (-11)	0 (-8)
NL	0 (-53)	0 (-29)	0 (126)	0 (255)	0 (125)
PL	0 (260)	0 (215)	0 (73)	0 (-31)	0 (88)
PT	0 (13)	0 (74)	0 (59)	0 (47)	0 (33)
RO	0 (0)	0 (-31)	0 (-69)	0 (-97)	0 (-58)
SE	0 (-30)	0 (-30)	0 (-20)	0 (-11)	0 (-19)
SI	0 (-10)	0 (-20)	0 (-13)	0 (-6)	0 (-8)
SK	0 (-80)	0 (-281)	0 (-636)	0 (-915)	0 (-573)
UK	0 (-9)	0 (233)	0 (365)	0 (479)	0 (279)
Total	**0 (-54)**	**0 (86)**	**0 (-4)**	**0 (-22)**	**0 (-37)**

Table 65. TSO revenue change of regulatory scenarios by country and stakeholder in the high demand case

T1								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-11	1	5	177	0 (-333)	0	0	172
BE	-79	0	-1	7	0 (107)	0	118	45
BG	32	-1	2	-53	0 (-178)	0	0	-19
CZ	-38	1	8	28	0 (-160)	1	0	0
DE	-818	65	0	1,094	0 (606)	20	0	362
DK	8	-12	0	0	0 (-25)	0	0	-3
EE	25	0	0	-10	0 (-23)	0	0	15
ES	8	0	0	-7	0 (105)	0	-71	-70
FI	135	0	0	-97	0 (20)	0	0	39
FR	56	0	25	-130	0 (61)	7	0	-42
GR	-6	0	0	4	0 (14)	0	81	78
HR	62	-39	7	0	0 (-46)	2	0	32
HU	278	-38	-2	-79	0 (-68)	0	0	158
IE	93	-5	0	0	0 (-56)	0	0	88
IT	75	-6	0	-212	0 (-173)	10	-157	-290
LT	-3	0	0	3	0 (17)	0	-5	-5
LU	-3	0	0	0	0 (-1)	0	0	-3
LV	6	0	0	-7	0 (-2)	0	0	-1
NL	-386	415	0	224	0 (-60)	-1	17	270
PL	107	-23	0	-81	0 (229)	-5	0	-2
PT	0	0	0	0	0 (12)	0	25	25
RO	415	-289	-45	-21	0 (-11)	0	0	60
SE	56	0	0	0	0 (-28)	0	0	56
SI	-13	0	0	1	0 (-9)	0	0	-12
SK	42	-1	0	-77	0 (25)	0	0	-36
UK	90	-35	-2	-164	0 (-36)	-5	-176	-292
Total	**131**	**34**	**-3**	**602**	**0 (-11)**	**30**	**-169**	**624**

Table 66. Welfare change of T1 regulatory scenario by country and stakeholder in the LNG glut case with TCF

T2								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-89	11	5	443	0 (-353)	0	0	371
BE	-222	0	-1	150	0 (201)	0	104	32
BG	12	0	2	-21	0 (-180)	0	0	-6
CZ	-110	3	8	91	0 (-160)	1	0	-7
DE	-1,513	121	0	2,073	0 (460)	15	0	697
DK	-18	26	0	0	0 (-25)	0	0	7
EE	17	0	0	-6	0 (-24)	0	0	10
ES	-263	0	0	197	0 (178)	0	-77	-142
FI	109	0	0	-78	0 (16)	0	0	31
FR	-306	0	25	198	0 (48)	7	3	-72
GR	-42	0	0	17	0 (86)	0	50	25
HR	51	-32	4	0	0 (-52)	2	0	25
HU	277	-38	-3	-79	0 (-109)	0	0	157
IE	53	-3	0	0	0 (-56)	0	0	50
IT	-519	40	0	168	0 (-112)	10	-159	-459
LT	-23	0	0	23	0 (35)	0	-2	-1
LU	-14	0	0	0	0 (-1)	0	0	-14
LV	-3	0	0	4	0 (-4)	0	0	1
NL	-698	750	0	296	0 (-51)	-1	15	362
PL	-56	12	0	45	0 (203)	-5	0	-4
PT	-36	0	0	18	0 (66)	0	24	6
RO	420	-295	-42	-21	0 (-36)	0	0	62
SE	36	0	0	0	0 (-29)	0	0	36
SI	-16	0	0	2	0 (-17)	0	0	-15
SK	-7	0	0	-14	0 (-147)	0	0	-21
UK	-561	224	-2	33	0 (65)	-3	-191	-501
Total	-3,522	819	-4	3,541	0 (3)	27	-231	630

Table 67. Welfare change of T2 regulatory scenario by country and stakeholder in the LNG glut case with TCF

T3								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-84	6	5	424	0 (-307)	0	0	351
BE	-214	0	-1	109	0 (123)	0	103	-3
BG	13	-1	2	-39	0 (-169)	0	0	-24
CZ	-106	2	8	57	0 (-121)	1	0	-39
DE	-1,472	91	0	1,753	0 (263)	14	0	385
DK	-17	5	0	0	0 (-12)	0	0	-12
EE	17	0	0	-8	0 (-22)	0	0	9
ES	-244	0	0	88	0 (185)	0	-77	-234
FI	110	0	0	-88	0 (18)	0	0	21
FR	-285	0	25	49	0 (122)	7	3	-200
GR	-40	0	0	9	0 (20)	0	63	32
HR	47	-37	5	0	0 (-38)	2	0	18
HU	247	-40	-3	-82	0 (-69)	0	0	122
IE	56	-4	0	0	0 (-37)	0	0	51
IT	-484	15	0	-41	0 (108)	10	-159	-658
LT	-22	0	0	12	0 (25)	0	-2	-13
LU	-13	0	0	0	0 (4)	0	0	-13
LV	-3	0	0	-2	0 (-6)	0	0	-5
NL	-680	565	0	250	0 (95)	-1	15	149
PL	-47	-7	0	-24	0 (66)	-5	0	-83
PT	-34	0	0	9	0 (53)	0	24	-1
RO	409	-334	-30	-24	0 (-73)	0	0	21
SE	37	0	0	0	0 (-19)	0	0	37
SI	-17	0	0	1	0 (-10)	0	0	-16
SK	-4	0	0	-48	0 (-477)	0	0	-53
UK	-524	81	-2	-75	0 (248)	-4	-189	-713
Total	**-3,356**	**342**	**10**	**2,327**	**0 (-30)**	**26**	**-219**	**-870**

Table 68. Welfare change of T3 regulatory scenario by country and stakeholder in the LNG glut case with TCF

T4								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-79	1	5	401	0 (-267)	0	0	328
BE	-204	0	-1	70	0 (63)	0	111	-25
BG	13	-1	2	-53	0 (-160)	0	0	-39
CZ	-102	1	8	26	0 (-93)	1	0	-66
DE	-1,429	64	0	1,619	0 (117)	17	0	272
DK	-15	-13	0	0	0 (0)	0	0	-28
EE	17	0	0	-10	0 (-20)	0	0	8
ES	-225	0	0	-8	0 (196)	0	-77	-309
FI	111	0	0	-97	0 (20)	0	0	13
FR	-262	0	25	-251	0 (191)	7	0	-481
GR	-40	0	0	4	0 (-33)	0	64	28
HR	44	-41	7	0	0 (-25)	2	0	11
HU	222	-41	-3	-85	0 (-35)	0	0	93
IE	58	-5	0	0	0 (-20)	0	0	53
IT	-445	-7	0	-224	0 (294)	11	-157	-823
LT	-22	0	0	3	0 (17)	0	10	-10
LU	-13	0	0	0	0 (8)	0	0	-13
LV	-2	0	0	-7	0 (-8)	0	0	-9
NL	-660	406	0	224	0 (216)	-1	16	-14
PL	-36	-24	0	-85	0 (-41)	-5	0	-150
PT	-31	0	0	0	0 (42)	0	25	-6
RO	398	-367	-19	-26	0 (-102)	0	0	-14
SE	39	0	0	0	0 (-11)	0	0	39
SI	-18	0	0	1	0 (-5)	0	0	-17
SK	-1	-1	0	-79	0 (-741)	0	0	-81
UK	-482	-43	-2	-169	0 (407)	-3	-189	-888
Total	**-3,166**	**-71**	**22**	**1,255**	**0 (10)**	**30**	**-198**	**-2,129**

Table 69. Welfare change of T4 regulatory scenario by country and stakeholder in the LNG glut case with TCF

T5								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-51	1	5	304	0 (-296)	0	0	260
BE	-151	0	-1	42	0 (84)	0	116	6
BG	21	-1	2	-53	0 (-167)	0	0	-31
CZ	-75	1	8	26	0 (-122)	1	0	-38
DE	-1,171	64	0	1,346	0 (326)	19	0	257
DK	-5	-12	0	0	0 (-10)	0	0	-18
EE	20	0	0	-10	0 (-21)	0	0	11
ES	-128	0	0	-7	0 (159)	0	-77	-212
FI	121	0	0	-97	0 (20)	0	0	24
FR	-128	0	25	-105	0 (138)	7	0	-201
GR	-26	0	0	4	0 (-13)	0	75	53
HR	51	-41	7	0	0 (-34)	2	0	20
HU	245	-40	-3	-82	0 (-48)	0	0	120
IE	73	-5	0	0	0 (-35)	0	0	68
IT	-226	-7	0	-221	0 (102)	10	-157	-602
LT	-14	0	0	3	0 (17)	0	9	-3
LU	-9	0	0	0	0 (4)	0	0	-9
LV	1	0	0	-7	0 (-6)	0	0	-6
NL	-545	408	0	169	0 (102)	-1	16	47
PL	24	-23	0	-84	0 (75)	-5	0	-89
PT	-18	0	0	0	0 (30)	0	25	7
RO	405	-334	-30	-24	0 (-62)	0	0	17
SE	46	0	0	0	0 (-18)	0	0	46
SI	-16	0	0	1	0 (-7)	0	0	-15
SK	17	-1	0	-78	0 (-416)	0	0	-62
UK	-242	-41	-2	-168	0 (225)	-4	-185	-642
Total	**-1,782**	**-32**	**11**	**958**	**0 (27)**	**30**	**-178**	**-993**

Table 70. Welfare change of T5 regulatory scenario by country and stakeholder in the LNG glut case with TCF

EURm/year change	T1	T2	T3	T4	T5
AT	0 (-333)	0 (-353)	0 (-307)	0 (-267)	0 (-296)
BE	0 (107)	0 (201)	0 (123)	0 (63)	0 (84)
BG	0 (-178)	0 (-180)	0 (-169)	0 (-160)	0 (-167)
CZ	0 (-160)	0 (-160)	0 (-121)	0 (-93)	0 (-122)
DE	0 (606)	0 (460)	0 (263)	0 (117)	0 (326)
DK	0 (-25)	0 (-25)	0 (-12)	0 (0)	0 (-10)
EE	0 (-23)	0 (-24)	0 (-22)	0 (-20)	0 (-21)
ES	0 (105)	0 (178)	0 (185)	0 (196)	0 (159)
FI	0 (20)	0 (16)	0 (18)	0 (20)	0 (20)
FR	0 (61)	0 (48)	0 (122)	0 (191)	0 (138)
GR	0 (14)	0 (86)	0 (20)	0 (-33)	0 (-13)
HR	0 (-46)	0 (-52)	0 (-38)	0 (-25)	0 (-34)
HU	0 (-68)	0 (-109)	0 (-69)	0 (-35)	0 (-48)
IE	0 (-56)	0 (-56)	0 (-37)	0 (-20)	0 (-35)
IT	0 (-173)	0 (-112)	0 (108)	0 (294)	0 (102)
LT	0 (17)	0 (35)	0 (25)	0 (17)	0 (17)
LU	0 (-1)	0 (-1)	0 (4)	0 (8)	0 (4)
LV	0 (-2)	0 (-4)	0 (-6)	0 (-8)	0 (-6)
NL	0 (-60)	0 (-51)	0 (95)	0 (216)	0 (102)
PL	0 (229)	0 (203)	0 (66)	0 (-41)	0 (75)
PT	0 (12)	0 (66)	0 (53)	0 (42)	0 (30)
RO	0 (-11)	0 (-36)	0 (-73)	0 (-102)	0 (-62)
SE	0 (-28)	0 (-29)	0 (-19)	0 (-11)	0 (-18)
SI	0 (-9)	0 (-17)	0 (-10)	0 (-5)	0 (-7)
SK	0 (25)	0 (-147)	0 (-477)	0 (-741)	0 (-416)
UK	0 (-36)	0 (65)	0 (248)	0 (407)	0 (225)
Total	**0 (-11)**	**0 (3)**	**0 (-30)**	**0 (10)**	**0 (27)**

Table 71. TSO revenue change of regulatory scenarios by country and stakeholder in the LNG glut case

T1								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	110	-15	1	-140	0 (-314)	0	0	-43
BE	181	0	0	-160	0 (76)	0	0	21
BG	43	-2	-11	-44	0 (-178)	-1	0	-15
CZ	88	-2	0	-82	0 (-111)	0	0	4
DE	323	-28	0	-463	0 (520)	29	0	-139
DK	48	-73	0	0	0 (-20)	0	0	-25
EE	21	0	0	-8	0 (-16)	0	0	13
ES	-253	0	-15	243	0 (175)	0	78	52
FI	105	0	0	-82	0 (20)	0	0	23
FR	680	-1	25	-642	0 (72)	2	0	65
GR	62	0	0	-73	0 (6)	0	-40	-51
HR	71	-45	0	0	0 (-2)	0	0	26
HU	204	-29	-13	-63	0 (35)	0	0	98
IE	175	-11	-1	0	0 (-48)	0	0	163
IT	986	-84	0	-841	0 (-192)	9	0	70
LT	14	0	0	-8	0 (12)	0	5	12
LU	13	0	0	0	0 (0)	0	0	13
LV	7	0	8	-11	0 (-4)	2	0	6
NL	210	-241	0	19	0 (-104)	-5	0	-18
PL	308	-71	-6	-247	0 (203)	-8	0	-24
PT	10	0	0	-7	0 (-28)	0	-72	-68
RO	158	-133	3	-10	0 (-22)	0	0	19
SE	80	0	0	0	0 (-25)	0	0	80
SI	6	0	0	-1	0 (12)	0	0	6
SK	120	-2	0	-167	0 (123)	0	0	-49
UK	1,630	-684	-26	-883	0 (-210)	-12	0	25
Total	**5,401**	**-1,420**	**-34**	**-3,668**	**0 (-23)**	**15**	**-30**	**264**

Table 72. Welfare change of T1 regulatory scenario by country and stakeholder in the LNG scarce case with TCF

T2								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	119	-16	1	-149	0 (-316)	0	0	-44
BE	198	0	0	-170	0 (71)	0	0	27
BG	48	-2	-11	-50	0 (-174)	-1	0	-17
CZ	96	-3	0	-90	0 (-111)	0	0	5
DE	406	-35	0	-538	0 (403)	28	0	-139
DK	51	-78	0	0	0 (-21)	0	0	-26
EE	14	0	0	-5	0 (-15)	0	0	9
ES	-456	1	-15	420	0 (267)	0	70	19
FI	83	0	0	-64	0 (17)	0	0	19
FR	723	-1	25	-672	0 (78)	2	0	78
GR	58	0	0	-72	0 (4)	0	-39	-54
HR	74	-47	0	0	0 (-3)	0	0	27
HU	214	-30	-13	-65	0 (31)	0	0	104
IE	180	-11	-1	0	0 (-48)	0	0	167
IT	1,056	-90	0	-889	0 (-143)	9	0	86
LT	-2	0	0	8	0 (19)	0	1	8
LU	14	0	0	0	0 (0)	0	0	14
LV	-1	0	8	-1	0 (-5)	2	0	9
NL	247	-285	0	16	0 (-104)	-5	0	-26
PL	328	-75	-6	-264	0 (188)	-8	0	-25
PT	-17	0	0	9	0 (-29)	0	-72	-79
RO	184	-154	3	-11	0 (-45)	0	0	22
SE	82	0	0	0	0 (-25)	0	0	82
SI	7	0	0	-1	0 (12)	0	0	6
SK	126	-2	0	-174	0 (55)	0	0	-50
UK	1,707	-717	-26	-908	0 (-144)	-12	0	44
Total	**5,541**	**-1544**	**-33**	**-3,671**	**0 (-33)**	**14**	**-40**	**266**

Table 73. Welfare change of T2 regulatory scenario by country and stakeholder in the LNG scarce case with TCF

T3								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	126	-21	1	-179	0 (-277)	0	0	-73
BE	209	0	0	-213	0 (46)	0	0	-4
BG	53	-3	-11	-69	0 (-165)	-1	0	-31
CZ	102	-3	0	-123	0 (-81)	0	0	-24
DE	463	-65	0	-809	0 (218)	28	0	-383
DK	53	-98	0	0	0 (-10)	0	0	-44
EE	15	0	0	-7	0 (-13)	0	0	8
ES	-433	1	-16	314	0 (256)	0	69	-65
FI	86	0	0	-75	0 (17)	0	0	11
FR	753	-1	25	-797	0 (135)	2	0	-17
GR	66	0	0	-81	0 (-14)	0	-45	-60
HR	76	-54	0	0	0 (11)	0	0	22
HU	192	-32	-13	-68	0 (66)	0	0	78
IE	183	-12	-1	0	0 (-32)	0	0	169
IT	1,104	-114	0	-1,090	0 (40)	9	0	-90
LT	0	0	0	-1	0 (15)	0	2	1
LU	15	0	0	0	0 (4)	0	0	15
LV	0	0	8	-7	0 (-8)	2	0	4
NL	273	-462	0	-22	0 (20)	-5	0	-217
PL	341	-93	-6	-337	0 (65)	-8	0	-103
PT	-14	0	0	0	0 (-16)	0	-72	-86
RO	209	-210	3	-15	0 (-96)	0	0	-13
SE	84	0	0	0	0 (-17)	0	0	84
SI	8	0	0	-1	0 (14)	0	0	6
SK	130	-3	0	-201	0 (-198)	0	0	-73
UK	1,760	-854	-26	-1,012	0 (17)	-12	0	-143
Total	**5,856**	**-2,025**	**-34**	**-4,793**	**0 (-2)**	**14**	**-46**	**-1,028**

Table 74. Welfare change of T3 regulatory scenario by country and stakeholder in the LNG scarce case with TCF

T4								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	132	-25	1	-202	0 (-249)	0	0	-94
BE	221	0	0	-249	0 (26)	0	0	-28
BG	54	-3	-11	-79	0 (-160)	-1	0	-40
CZ	108	-4	0	-151	0 (-58)	0	0	-46
DE	520	-90	0	-1,058	0 (50)	27	0	-600
DK	56	-114	0	0	0 (-1)	0	0	-58
EE	15	0	0	-8	0 (-13)	0	0	7
ES	-418	0	-16	234	0 (243)	0	70	-130
FI	87	0	0	-83	0 (17)	0	0	4
FR	783	-1	25	-900	0 (180)	2	0	-91
GR	72	0	0	-88	0 (-32)	0	-45	-60
HR	78	-60	0	0	0 (22)	0	0	18
HU	169	-34	-3	-71	0 (95)	0	0	60
IE	187	-13	-1	0	0 (-19)	0	0	171
IT	1,153	-134	0	-1,256	0 (183)	9	0	-229
LT	1	0	0	-8	0 (11)	0	2	-5
LU	16	0	0	0	0 (8)	0	0	16
LV	1	0	8	-12	0 (-10)	2	0	-1
NL	298	-610	0	-35	0 (123)	-5	0	-351
PL	355	-109	-6	-392	0 (-37)	-8	0	-160
PT	-12	0	0	-8	0 (-5)	0	-72	-91
RO	212	-241	4	-17	0 (-139)	0	0	-42
SE	85	0	0	0	0 (-10)	0	0	85
SI	8	0	0	-2	0 (17)	0	0	7
SK	134	-3	0	-223	0 (-400)	0	0	-92
UK	1,814	-967	-26	-1,098	0 (141)	-12	0	-289
Total	**6,130**	**-2,408**	**-24**	**-5,706**	**0 (-18)**	**13**	**-44**	**-2,038**

Table 75. Welfare change of T4 regulatory scenario by country and stakeholder in the LNG scarce case with TCF

T5								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	122	-21	1	-177	0 (-278)	0	0	-75
BE	203	0	0	-211	0 (55)	0	0	-9
BG	53	-3	-11	-69	0 (-166)	-1	0	-31
CZ	99	-3	0	-122	0 (-80)	0	0	-26
DE	430	-63	0	-788	0 (255)	28	0	-394
DK	52	-97	0	0	0 (-9)	0	0	-44
EE	18	0	0	-8	0 (-14)	0	0	10
ES	-347	0	-16	234	0 (217)	0	70	-58
FI	95	0	0	-83	0 (18)	0	0	12
FR	736	-1	25	-791	0 (138)	2	0	-29
GR	69	0	0	-83	0 (-13)	0	-45	-58
HR	75	-54	0	0	0 (11)	0	0	21
HU	191	-33	-13	-69	0 (67)	0	0	77
IE	181	-12	-1	0	0 (-31)	0	0	167
IT	1,076	-113	0	-1,080	0 (30)	9	0	-108
LT	7	0	0	-8	0 (11)	0	3	2
LU	15	0	0	0	0 (4)	0	0	15
LV	3	0	8	-12	0 (-7)	2	0	2
NL	258	-454	0	-27	0 (35)	-5	0	-228
PL	333	-93	-6	-333	0 (65)	-8	0	-107
PT	-2	0	0	-8	0 (-15)	0	-72	-82
RO	206	-210	3	-15	0 (-89)	0	0	-15
SE	83	0	0	0	0 (-16)	0	0	83
SI	7	0	0	-1	0 (15)	0	0	6
SK	127	-3	0	-199	0 (-186)	0	0	-74
UK	1,729	-847	-26	-1,007	0 (-2)	-12	0	-163
Total	5,819	-2005	-34	-4,856	0 (16)	14	-43	-1,106

Table 76. Welfare change of T5 regulatory scenario by country and stakeholder in the LNG scarce case with TCF

EURm/year change	T1	T2	T3	T4	T5
AT	0 (-314)	0 (-316)	0 (-277)	0 (-249)	0 (-278)
BE	0 (76)	0 (71)	0 (46)	0 (26)	0 (55)
BG	0 (-178)	0 (-174)	0 (-165)	0 (-160)	0 (-166)
CZ	0 (-111)	0 (-111)	0 (-81)	0 (-58)	0 (-80)
DE	0 (520)	0 (403)	0 (218)	0 (50)	0 (255)
DK	0 (-20)	0 (-21)	0 (-10)	0 (-1)	0 (-9)
EE	0 (-16)	0 (-15)	0 (-13)	0 (-13)	0 (-14)
ES	0 (175)	0 (267)	0 (256)	0 (243)	0 (217)
FI	0 (20)	0 (17)	0 (17)	0 (17)	0 (18)
FR	0 (72)	0 (78)	0 (135)	0 (180)	0 (138)
GR	0 (6)	0 (4)	0 (-14)	0 (-32)	0 (-13)
HR	0 (-2)	0 (-3)	0 (11)	0 (22)	0 (11)
HU	0 (35)	0 (31)	0 (66)	0 (95)	0 (67)
IE	0 (-48)	0 (-48)	0 (-32)	0 (-19)	0 (-31)
IT	0 (-192)	0 (-143)	0 (40)	0 (183)	0 (30)
LT	0 (12)	0 (19)	0 (15)	0 (11)	0 (11)
LU	0 (0)	0 (0)	0 (4)	0 (8)	0 (4)
LV	0 (-4)	0 (-5)	0 (-8)	0 (-10)	0 (-7)
NL	0 (-104)	0 (-104)	0 (20)	0 (123)	0 (35)
PL	0 (203)	0 (188)	0 (65)	0 (-37)	0 (65)
PT	0 (-28)	0 (-29)	0 (-16)	0 (-5)	0 (-15)
RO	0 (-22)	0 (-45)	0 (-96)	0 (-139)	0 (-89)
SE	0 (-25)	0 (-25)	0 (-17)	0 (-10)	0 (-16)
SI	0 (12)	0 (12)	0 (14)	0 (17)	0 (15)
SK	0 (123)	0 (55)	0 (-198)	0 (-400)	0 (-186)
UK	0 (-210)	0 (-144)	0 (17)	0 (141)	0 (-2)
Total	**0 (-23)**	**0 (-33)**	**0 (-2)**	**0 (-18)**	**0 (16)**

Table 77. TSO revenue change of regulatory scenarios by country and stakeholder in the LNG scarce case

T1								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	67	-8	-2	-53	0 (-396)	-3	0	0
BE	174	0	-3	-137	0 (48)	0	0	35
BG	28	-1	1	-46	0 (-68)	0	0	-18
CZ	58	-1	0	-52	0 (-151)	0	0	5
DE	-15	1	0	-156	0 (1096)	19	0	-151
DK	38	-53	1	0	0 (-25)	0	0	-15
EE	20	0	0	-8	0 (-22)	0	0	12
ES	-35	0	-1	32	0 (155)	1	-17	-20
FI	118	0	0	-87	0 (19)	0	0	31
FR	756	-1	-55	-598	0 (45)	0	0	102
GR	-3	0	0	1	0 (-5)	0	4	2
HR	132	-82	8	0	0 (0)	2	0	61
HU	162	-18	-51	-35	0 (23)	2	0	60
IE	196	-11	-2	0	0 (-52)	0	0	182
IT	1,878	-147	0	-1,212	0 (-261)	14	0	533
LT	-1	0	0	2	0 (16)	0	7	8
LU	13	0	0	0	0 (-1)	0	0	13
LV	2	0	0	-3	0 (0)	1	0	1
NL	233	-245	0	-39	0 (-122)	-5	0	-56
PL	243	-52	-6	-190	0 (247)	-8	0	-13
PT	0	0	0	0	0 (8)	0	14	14
RO	320	-225	-43	-16	0 (-1)	0	0	36
SE	76	0	0	0	0 (-27)	0	0	76
SI	6	0	0	-1	0 (-43)	0	0	5
SK	44	-1	0	-49	0 (-224)	0	0	-6
UK	1,891	-729	-39	-890	0 (-258)	0	-5	226
Total	6,399	-1573	-192	-3,537	0 (2)	23	3	1,123

Table 78. Welfare change of T1 regulatory scenario by country and stakeholder in the NS1 case with TCF

T2								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	79	-10	-3	-56	0 (-385)	-3	0	7
BE	199	0	-3	-151	0 (40)	0	0	45
BG	7	0	1	-12	0 (-74)	0	0	-4
CZ	70	-2	0	-63	0 (-145)	0	0	6
DE	103	-8	0	-259	0 (856)	20	0	-145
DK	42	-60	1	0	0 (-25)	0	0	-17
EE	12	0	0	-5	0 (-22)	0	0	7
ES	-292	1	-1	233	0 (236)	1	-18	-76
FI	90	0	0	-67	0 (16)	0	0	23
FR	817	-1	-55	-638	0 (52)	0	0	123
GR	-40	0	0	15	0 (12)	0	-14	-39
HR	134	-83	9	0	0 (1)	2	0	62
HU	161	-18	-51	-35	0 (24)	2	0	59
IE	202	-12	-2	0	0 (-52)	0	0	189
IT	1,958	-154	0	-1,264	0 (-208)	14	0	554
LT	-22	0	0	20	0 (31)	0	3	1
LU	14	0	0	0	0 (-1)	0	0	14
LV	-7	0	0	9	0 (-2)	2	0	3
NL	285	-302	0	-61	0 (-124)	-5	0	-82
PL	270	-57	-6	-211	0 (229)	-8	0	-13
PT	-34	0	0	18	0 (53)	0	13	-4
RO	326	-232	-40	-17	0 (-12)	0	0	38
SE	79	0	0	0	0 (-27)	0	0	79
SI	7	0	0	-1	0 (-42)	0	0	6
SK	43	-1	0	-48	0 (-259)	0	0	-6
UK	2,001	-773	-39	-924	0 (-190)	0	-5	259
Total	**6,505**	**-1,712**	**-190**	**-3,516**	**0 (-18)**	**24**	**-22**	**1,090**

Table 79. Welfare change of T2 regulatory scenario by country and stakeholder in the NS1 case with TCF

T3								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	88	-15	-3	-86	0 (-328)	-3	0	-20
BE	215	0	-3	-197	0 (17)	0	0	15
BG	10	-1	1	-31	0 (-63)	0	0	-21
CZ	80	-3	0	-100	0 (-100)	0	0	-22
DE	195	-41	0	-659	0 (329)	20	0	-485
DK	45	-81	1	0	0 (-13)	0	0	-35
EE	13	0	0	-7	0 (-20)	0	0	6
ES	-260	0	-1	120	0 (237)	1	-15	-155
FI	93	0	0	-78	0 (16)	0	0	15
FR	865	-1	-55	-777	0 (119)	0	0	33
GR	-35	0	0	7	0 (-24)	0	12	-16
HR	135	-91	9	0	0 (16)	2	0	56
HU	136	-20	-51	-39	0 (63)	2	0	29
IE	206	-13	-2	0	0 (-34)	0	0	192
IT	2,033	-180	0	-1,484	0 (-2)	15	0	383
LT	-19	0	0	10	0 (23)	0	6	-4
LU	16	0	0	0	0 (3)	0	0	16
LV	-6	0	0	2	0 (-5)	2	0	-2
NL	321	-493	0	-83	0 (28)	-5	0	-260
PL	292	-78	-6	-285	0 (120)	-8	0	-86
PT	-30	0	0	8	0 (42)	0	13	-9
RO	317	-270	-28	-19	0 (5)	0	0	1
SE	81	0	0	0	0 (-18)	0	0	81
SI	7	0	0	-2	0 (-38)	0	0	6
SK	29	-1	0	-56	0 (-371)	0	0	-28
UK	2,063	-918	-37	-1,034	0 (-10)	0	-5	70
Total	**6,892**	**-2,204**	**-173**	**-4,790**	**0 (-7)**	**25**	**10**	**-240**

Table 80. Welfare change of T3 regulatory scenario by country and stakeholder in the NS1 case with TCF

T4								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	96	-20	-3	-110	0 (-285)	-4	0	-40
BE	230	0	-2	-235	0 (2)	0	0	-7
BG	12	-1	1	-47	0 (-54)	0	0	-35
CZ	88	-4	0	-129	0 (-66)	0	0	-43
DE	272	-67	0	-934	0 (-83)	21	0	-708
DK	48	-98	1	0	0 (-4)	0	0	-49
EE	14	0	0	-8	0 (-19)	0	0	6
ES	-234	0	-1	32	0 (238)	1	-18	-220
FI	96	0	0	-87	0 (17)	0	0	9
FR	906	-1	-55	-887	0 (171)	0	0	-36
GR	-32	0	0	1	0 (-53)	0	-8	-38
HR	136	-96	10	0	0 (27)	2	0	52
HU	119	-22	-48	-43	0 (92)	1	0	8
IE	210	-14	-2	0	0 (-20)	0	0	195
IT	2,093	-201	0	-1,656	0 (156)	15	0	251
LT	-17	0	0	2	0 (16)	0	14	-1
LU	17	0	0	0	0 (7)	0	0	17
LV	-5	0	0	-3	0 (-7)	1	0	-6
NL	353	-645	0	-113	0 (127)	-5	0	-411
PL	310	-94	-6	-344	0 (34)	-8	0	-142
PT	-27	0	0	0	0 (34)	0	13	-14
RO	311	-299	-18	-21	0 (19)	0	0	-28
SE	83	0	0	0	0 (-11)	0	0	83
SI	8	0	0	-2	0 (-35)	0	0	6
SK	17	-1	0	-55	0 (-461)	0	0	-39
UK	2,127	-1,034	-36	-1,123	0 (128)	0	-5	-71
Total	**7,233**	**-2,597**	**-160**	**-5,760**	**0 (-29)**	**24**	**-3**	**-1,263**

Table 81. Welfare change of T4 regulatory scenario by country and stakeholder in the NS1 case with TCF

T5								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	85	-15	-3	-85	0 (-328)	-3	0	-22
BE	210	0	-3	-197	0 (21)	0	0	10
BG	19	-1	1	-46	0 (-59)	0	0	-28
CZ	77	-3	0	-99	0 (-99)	0	0	-24
DE	163	-40	0	-639	0 (383)	20	0	-496
DK	44	-81	1	0	0 (-12)	0	0	-35
EE	16	0	0	-8	0 (-20)	0	0	8
ES	-154	0	-1	32	0 (204)	1	-16	-138
FI	105	0	0	-87	0 (18)	0	0	18
FR	849	-1	-55	-773	0 (122)	0	0	21
GR	-20	0	0	1	0 (-34)	0	-8	-27
HR	135	-90	9	0	0 (16)	2	0	56
HU	135	-20	-51	-39	0 (65)	2	0	27
IE	205	-13	-2	0	0 (-33)	0	0	190
IT	2,002	-179	0	-1,474	0 (-12)	15	0	363
LT	-11	0	0	2	0 (16)	0	22	13
LU	15	0	0	0	0 (4)	0	0	15
LV	-2	0	0	-3	0 (-4)	1	0	-4
NL	310	-489	0	-91	0 (28)	-5	0	-276
PL	284	-77	-6	-283	0 (117)	-8	0	-90
PT	-16	0	0	0	0 (24)	0	14	-2
RO	315	-270	-28	-19	0 (10)	0	0	-2
SE	81	0	0	0	0 (-18)	0	0	81
SI	7	0	0	-2	0 (-38)	0	0	6
SK	28	-1	0	-56	0 (-365)	0	0	-29
UK	2,047	-917	-38	-1,033	0 (-29)	0	-5	54
Total	**6,928**	**-2,196**	**-176**	**-4,898**	**0 (-24)**	**25**	**6**	**-312**

Table 82. Welfare change of T5 regulatory scenario by country and stakeholder in the NS1 case with TCF

EURm/year change	T1	T2	T3	T4	T5
AT	0 (-396)	0 (-385)	0 (-328)	0 (-285)	0 (-328)
BE	0 (48)	0 (40)	0 (17)	0 (2)	0 (21)
BG	0 (-68)	0 (-74)	0 (-63)	0 (-54)	0 (-59)
CZ	0 (-151)	0 (-145)	0 (-100)	0 (-66)	0 (-99)
DE	0 (1096)	0 (856)	0 (329)	0 (-83)	0 (383)
DK	0 (-25)	0 (-25)	0 (-13)	0 (-4)	0 (-12)
EE	0 (-22)	0 (-22)	0 (-20)	0 (-19)	0 (-20)
ES	0 (155)	0 (236)	0 (237)	0 (238)	0 (204)
FI	0 (19)	0 (16)	0 (16)	0 (17)	0 (18)
FR	0 (45)	0 (52)	0 (119)	0 (171)	0 (122)
GR	0 (-5)	0 (12)	0 (-24)	0 (-53)	0 (-34)
HR	0 (0)	0 (1)	0 (16)	0 (27)	0 (16)
HU	0 (23)	0 (24)	0 (63)	0 (92)	0 (65)
IE	0 (-52)	0 (-52)	0 (-34)	0 (-20)	0 (-33)
IT	0 (-261)	0 (-208)	0 (-2)	0 (156)	0 (-12)
LT	0 (16)	0 (31)	0 (23)	0 (16)	0 (16)
LU	0 (-1)	0 (-1)	0 (3)	0 (7)	0 (4)
LV	0 (0)	0 (-2)	0 (-5)	0 (-7)	0 (-4)
NL	0 (-122)	0 (-124)	0 (28)	0 (127)	0 (28)
PL	0 (247)	0 (229)	0 (120)	0 (34)	0 (117)
PT	0 (8)	0 (53)	0 (42)	0 (34)	0 (24)
RO	0 (-1)	0 (-12)	0 (5)	0 (19)	0 (10)
SE	0 (-27)	0 (-27)	0 (-18)	0 (-11)	0 (-18)
SI	0 (-43)	0 (-42)	0 (-38)	0 (-35)	0 (-38)
SK	0 (-224)	0 (-259)	0 (-371)	0 (-461)	0 (-365)
UK	0 (-258)	0 (-190)	0 (-10)	0 (128)	0 (-29)
Total	**0 (2)**	**0 (-18)**	**0 (-7)**	**0 (-29)**	**0 (-24)**

Table 83. TSO revenue change of regulatory scenarios by country and stakeholder in the NS1 case

T1								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-71	9	12	-19	0 (-137)	9	0	-60
BE	79	0	3	-56	0 (29)	0	0	26
BG	31	-1	2	-52	0 (-60)	0	0	-20
CZ	25	-1	0	-22	0 (-141)	0	0	2
DE	-332	27	0	439	0 (902)	13	0	146
DK	24	-34	1	0	0 (-25)	0	0	-9
EE	21	0	0	-8	0 (-21)	0	0	13
ES	-24	0	0	22	0 (128)	1	-21	-23
FI	119	0	0	-88	0 (16)	0	0	31
FR	486	0	59	-473	0 (8)	0	0	72
GR	0	0	0	-2	0 (18)	0	9	6
HR	64	-40	0	0	0 (-3)	2	0	26
HU	144	-21	0	-44	0 (-42)	1	0	79
IE	165	-10	-1	0	0 (-52)	0	0	154
IT	-900	74	0	614	0 (-64)	-13	166	-59
LT	0	0	0	0	0 (15)	0	1	1
LU	4	0	0	0	0 (0)	0	0	4
LV	3	0	0	-3	0 (-1)	2	0	1
NL	74	-81	0	16	0 (-76)	5	0	14
PL	165	-35	-6	-129	0 (211)	-8	0	-14
PT	0	0	0	0	0 (8)	0	19	18
RO	130	-105	-1	-7	0 (-10)	0	0	17
SE	65	0	0	0	0 (-27)	0	0	65
SI	4	0	0	0	0 (-27)	0	0	3
SK	12	0	0	-13	0 (-356)	-2	0	-3
UK	1,343	-531	-18	-747	0 (-261)	0	-5	42
Total	**1,628**	**-749**	**52**	**-574**	**0 (29)**	**9**	**168**	**535**

Table 84. Welfare change of T1 regulatory scenario by country and stakeholder in the NS2 case with TCF

T2								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-72	9	12	172	0 (-215)	9	0	131
BE	88	0	4	-60	0 (32)	0	0	32
BG	13	0	2	-22	0 (-66)	0	0	-8
CZ	34	-1	0	-31	0 (-137)	0	0	3
DE	-241	19	0	314	0 (643)	13	0	105
DK	27	-39	1	0	0 (-25)	0	0	-11
EE	14	0	0	-5	0 (-22)	0	0	8
ES	-248	0	0	197	0 (199)	1	-22	-72
FI	97	0	0	-72	0 (13)	0	0	25
FR	504	0	71	-490	0 (12)	0	0	85
GR	-33	0	0	10	0 (53)	0	7	-15
HR	64	-40	0	0	0 (-3)	2	0	26
HU	143	-21	0	-43	0 (-44)	1	0	79
IE	168	-10	-1	0	0 (-52)	0	0	157
IT	-903	74	0	616	0 (57)	-13	73	-153
LT	-18	0	0	16	0 (27)	0	1	-1
LU	4	0	0	0	0 (0)	0	0	4
LV	-5	0	0	6	0 (-3)	2	0	3
NL	114	-125	0	23	0 (-67)	5	0	18
PL	186	-40	-6	-146	0 (195)	-8	0	-14
PT	-30	0	0	16	0 (48)	0	17	3
RO	135	-111	2	-8	0 (-18)	0	0	18
SE	68	0	0	0	0 (-27)	0	0	68
SI	4	0	0	0	0 (-27)	0	0	3
SK	12	0	0	-13	0 (-353)	-2	0	-3
UK	1,381	-550	-14	-762	0 (-196)	0	-5	50
Total	**1,505**	**-834**	**72**	**-282**	**0 (24)**	**10**	**71**	**542**

Table 85. Welfare change of T2 regulatory scenario by country and stakeholder in the NS2 case with TCF

T3								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-80	7	12	166	0 (-182)	9	0	114
BE	96	0	4	-95	0 (21)	0	0	5
BG	15	-1	2	-39	0 (-57)	0	0	-23
CZ	44	-2	0	-64	0 (-101)	0	0	-21
DE	-145	-10	0	-5	0 (172)	13	0	-147
DK	31	-59	1	0	0 (-15)	0	0	-27
EE	15	0	0	-7	0 (-20)	0	0	8
ES	-217	0	0	97	0 (196)	1	-22	-141
FI	100	0	0	-82	0 (13)	0	0	18
FR	520	-1	86	-599	0 (65)	0	0	6
GR	-28	0	0	3	0 (4)	0	15	-10
HR	61	-44	0	0	0 (6)	2	0	20
HU	133	-24	0	-50	0 (-20)	1	0	60
IE	170	-11	0	0	0 (-37)	0	0	159
IT	-971	62	0	515	0 (168)	-13	99	-308
LT	-15	0	0	7	0 (20)	0	1	-7
LU	5	0	0	0	0 (5)	0	0	5
LV	-4	0	0	0	0 (-5)	2	0	-2
NL	158	-303	0	-42	0 (62)	5	0	-182
PL	208	-58	-6	-213	0 (73)	-8	0	-77
PT	-26	0	0	7	0 (38)	0	18	-2
RO	143	-155	13	-11	0 (-5)	0	0	-11
SE	71	0	0	0	0 (-20)	0	0	71
SI	3	0	0	-1	0 (-25)	0	0	2
SK	7	0	0	-26	0 (-332)	-2	0	-22
UK	1,417	-669	-9	-854	0 (-45)	0	-5	-121
Total	**1,710**	**-1,268**	**103**	**-1,291**	**0 (-20)**	**10**	**105**	**-630**

Table 86. Welfare change of T3 regulatory scenario by country and stakeholder in the NS2 case with TCF

T4								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-87	5	12	163	0 (-156)	9	0	101
BE	101	0	5	-121	0 (16)	0	0	-15
BG	17	-1	2	-52	0 (-50)	0	0	-34
CZ	52	-2	0	-89	0 (-76)	0	0	-39
DE	-77	-33	0	-265	0 (-179)	13	0	-362
DK	33	-74	1	0	0 (-7)	0	0	-39
EE	16	0	0	-8	0 (-19)	0	0	7
ES	-194	0	0	22	0 (196)	1	-22	-194
FI	102	0	0	-90	0 (14)	0	0	13
FR	531	-1	96	-681	0 (109)	0	0	-54
GR	-25	0	0	-2	0 (-33)	0	0	-27
HR	59	-47	0	0	0 (12)	2	0	15
HU	129	-27	3	-56	0 (-3)	0	0	48
IE	172	-12	0	0	0 (-25)	0	0	161
IT	-1,025	53	0	439	0 (256)	-13	118	-428
LT	-13	0	0	0	0 (14)	0	1	-12
LU	5	0	0	0	0 (8)	0	0	5
LV	-3	0	0	-4	0 (-7)	2	0	-5
NL	188	-436	0	-39	0 (168)	5	0	-281
PL	224	-72	-6	-263	0 (-17)	-8	0	-124
PT	-23	0	0	0	0 (30)	0	18	-5
RO	149	-190	21	-14	0 (6)	0	0	-34
SE	72	0	0	0	0 (-14)	0	0	72
SI	2	0	0	-1	0 (-23)	0	0	1
SK	2	-1	0	-32	0 (-318)	-2	0	-32
UK	1,442	-759	-6	-923	0 (73)	0	-5	-252
Total	**1,849**	**-1,595**	**128**	**-2,017**	**0 (-26)**	**10**	**110**	**-1,514**

Table 87. Welfare change of T4 regulatory scenario by country and stakeholder in the NS2 case with TCF

T5								
EURm/ year change	**Consumer surplus**	**Producer surplus**	**Storage arbitrage**	**LTC holder profit**	**TSO**	**SSO**	**LSO**	**Total welfare with TCF**
AT	-81	6	12	111	0 (-157)	9	0	58
BE	92	0	4	-95	0 (20)	0	0	1
BG	23	-1	2	-52	0 (-54)	0	0	-29
CZ	41	-2	0	-62	0 (-101)	0	0	-23
DE	-181	-9	0	3	0 (248)	13	0	-174
DK	29	-58	1	0	0 (-14)	0	0	-27
EE	17	0	0	-8	0 (-20)	0	0	9
ES	-127	0	0	22	0 (169)	1	-22	-126
FI	108	0	0	-88	0 (15)	0	0	19
FR	513	-1	81	-598	0 (69)	0	0	-5
GR	-15	0	0	-2	0 (-12)	0	23	6
HR	61	-44	0	0	0 (7)	2	0	19
HU	133	-24	0	-50	0 (-18)	1	0	59
IE	169	-11	0	0	0 (-36)	0	0	158
IT	-975	61	0	508	0 (129)	-13	137	-281
LT	-8	0	0	0	0 (15)	0	1	-7
LU	5	0	0	0	0 (5)	0	0	5
LV	-1	0	0	-3	0 (-5)	2	0	-3
NL	142	-294	0	-25	0 (71)	5	0	-171
PL	200	-57	-6	-209	0 (74)	-8	0	-81
PT	-14	0	0	0	0 (22)	0	18	4
RO	141	-156	12	-11	0 (0)	0	0	-14
SE	70	0	0	0	0 (-19)	0	0	70
SI	3	0	0	-1	0 (-24)	0	0	2
SK	6	0	0	-27	0 (-332)	-2	0	-23
UK	1,401	-668	-11	-853	0 (-59)	0	-5	-136
Total	**1,752**	**-1,257**	**96**	**-1,443**	**0 (-9)**	**10**	**152**	**-690**

Table 88. Welfare change of T5 regulatory scenario by country and stakeholder in the NS2 case with TCF

EURm/year change	T1	T2	T3	T4	T5
AT	0 (-137)	0 (-215)	0 (-182)	0 (-156)	0 (-157)
BE	0 (29)	0 (32)	0 (21)	0 (16)	0 (20)
BG	0 (-60)	0 (-66)	0 (-57)	0 (-50)	0 (-54)
CZ	0 (-141)	0 (-137)	0 (-101)	0 (-76)	0 (-101)
DE	0 (902)	0 (643)	0 (172)	0 (-179)	0 (248)
DK	0 (-25)	0 (-25)	0 (-15)	0 (-7)	0 (-14)
EE	0 (-21)	0 (-22)	0 (-20)	0 (-19)	0 (-20)
ES	0 (128)	0 (199)	0 (196)	0 (196)	0 (169)
FI	0 (16)	0 (13)	0 (13)	0 (14)	0 (15)
FR	0 (8)	0 (12)	0 (65)	0 (109)	0 (69)
GR	0 (18)	0 (53)	0 (4)	0 (-33)	0 (-12)
HR	0 (-3)	0 (-3)	0 (6)	0 (12)	0 (7)
HU	0 (-42)	0 (-44)	0 (-20)	0 (-3)	0 (-18)
IE	0 (-52)	0 (-52)	0 (-37)	0 (-25)	0 (-36)
IT	0 (-64)	0 (57)	0 (168)	0 (256)	0 (129)
LT	0 (15)	0 (27)	0 (20)	0 (14)	0 (15)
LU	0 (0)	0 (0)	0 (5)	0 (8)	0 (5)
LV	0 (-1)	0 (-3)	0 (-5)	0 (-7)	0 (-5)
NL	0 (-76)	0 (-67)	0 (62)	0 (168)	0 (71)
PL	0 (211)	0 (195)	0 (73)	0 (-17)	0 (74)
PT	0 (8)	0 (48)	0 (38)	0 (30)	0 (22)
RO	0 (-10)	0 (-18)	0 (-5)	0 (6)	0 (0)
SE	0 (-27)	0 (-27)	0 (-20)	0 (-14)	0 (-19)
SI	0 (-27)	0 (-27)	0 (-25)	0 (-23)	0 (-24)
SK	0 (-356)	0 (-353)	0 (-332)	0 (-318)	0 (-332)
UK	0 (-261)	0 (-196)	0 (-45)	0 (73)	0 (-59)
Total	**0 (29)**	**0 (24)**	**0 (-20)**	**0 (-26)**	**0 (-9)**

Table 89. TSO revenue change of regulatory scenarios by country and stakeholder in the NS2 case

ANNEX 2: TRANSMISSION TARIFFS AND METHODOLOGY FOR THEIR BENCHMARKING

Transmission tariff benchmarking methodology applied in this study

To make baseline comparisons, transmission fees are estimated as a standardized transportation service for each relevant cross-border point and expressed in a common measurement unit (EUR/MWh). The assumed standard transportation service has the following characteristics:

- The duration of transmission contracts is one year
- Contracts refer to firm transportation services
- The booked maximum hourly capacity is 10 000 kWh
- Applied booked capacity usage ratio is 56.2%[164]
- Tariffs are expressed in EUR/MWh

Using our assumed capacity reservation level of 10 000 kWh/h for the yearly firm transmission service contract, we calculate the overall transportation fee (in EUR) that would be incurred by a shipper at each interconnection point (IP), making all the necessary conversions regarding gas reference conditions and currency units.

Once we have arrived at the total fee corresponding to the standardized service, tariffs can be determined on a per MWh basis (EUR/MWh), dividing total payments by the yearly transported volume (using the booked capacity usage ratio (56.2%)). The fee consists of the relevant exit plus entry fees due at the two sides of the border (including the commodity fee at the relevant point).[165]

From 2017 onwards, domestic exit points and production entry points are included in the model. Tariffs are calculated with the same methodology as in the case of IPs.

[164] Calculated as: (Average flow)/(Average booked capacity). Average booked capacity utilization in Europe is reported in the Acer Market Monitoring Report 2015, pp. 251-252.

[165] Where tariffs are set on an auction, reference price is included in the model, model calculates auction revenues

ANNEX 3: LITERATURE REVIEW ON GAS MARKET OPERATION EFFICIENCY IN THE EU

In their most recent Market Monitoring Report (MMR 2016), ACER and CEER acknowledged that the functioning of European gas wholesale markets continued to progress in 2016, with the development of hubs, more supply-side competition, improved price convergence, and better interconnection between markets. However, MMR (2016), previous MMRs, several other studies and academic articles have all pointed to some remaining inefficiencies that still hinder competition and trade in the European gas market. In this Annex we give an overview of these problems, and draw conclusions that will serve as a basis for developing our own methodology of assessing the efficiency of gas wholesale markets on the level of individual Member States.

As EWI (2016) and SEO (2016) argued, the question of competition and the resulting gas prices were especially relevant in Europe, because the production of natural gas predominantly takes place outside the EU. A major part of the producer surplus, therefore, do not count in the EU welfare (while consumer surplus entirely counts), and effective competition needs to be there to ensure that welfare is concentrated at the consumer side, rather than at the producer side of the market. Moreover, EWI (2016) argues that the demand of gas, at least in the short-run, is less price elastic than the gas supply function, so lower gas prices increase the consumer surplus more than they decrease the surplus of EU gas producers.

To assess market inefficiencies, Baringa (2016), SEO (2016) and CEPA (2016) presented their requirements of an ideal gas market. The features they described can be classified as follows:

- the lowest possible gas prices and price differences across the continent through effective competition and access to transmission capacity and markets, which leads to market integration;
- efficient use and expansion of the transmission infrastructure, including the allocation and utilisation of capacity in the short term, and the expansion and financing in the long term;
- security of gas supply across the EU, including having access to multiple sources of supply.

Analysing the actual functioning of the European gas market, several authors concluded that the market clearly showed some signs of effective competition and market integration, especially in North-West Europe (NWE). Renou-Maissant (2012) investigated the integration of the natural gas markets of Belgium, France, Germany, Italy, Spain and the UK between 1991 and 2009. She used time-varying parameter models, and found convergence between industrial gas prices across these countries, suggesting strong integration of gas markets in continental Europe. Decreasing price differences in NWE compared to American hubs (Baringa, 2016) and between EU countries (SUND, 2016), high correlation with low spreads between European hubs (CEPA, 2016), and the extension of hub-based pricing into Eastern and Southern European gas markets that were driving back the classic oil-indexed contracts (Baringa, 2016) were also observed as positive signs of market integration.

Price correlation and the role of hubs in efficient market functioning has been examined extensively in literature. Opolska (2017) found that policy tools increasing wholesale market liquidity and lowering entry barriers related to the gas network (VTP, market-based balancing, and market opening) had the greatest potential to increase competition (measured by the rate of supplier switching). Based on a detailed analysis of future European gas demand and supply trends, ACER (2015) concluded that diversification of sources and the establishment of well- functioning gas trading hubs were more important than ever. It added that there was a general trend towards more flexible and shorter-term contracts at all points of the value chain, the impacts of which were analysed by DNV KEMA (2013). That study found that in developed markets, short term contracts resulted in more gas hub-indexed prices, more market traded products and more market liquidity. On the flip side, MMR (2016) observed that long term contracts were still a limiting factor for hub liquidity.

DNV KEMA (2013) agreed that traded gas markets and new suppliers did not yet develop properly in Eastern Europe, where interconnectivity (including reverse flow) also remained a problem. The promotion of shorter term contracts and spot trading would likely improve competition and liquidity in these markets, as well as ensuring reverse flow to link Eastern European prices to Western European developments. Short term contracts, however, were not deemed to be sufficient for competition to develop in countries that relied on a single supplier and had no connection to other markets. The study suggested that if interconnectivity were improved and shorter-term contracts and spot trading were promoted, hubs would emerge in the region with price differentials not exceeding the short-term cost of transport between markets. An additional tool could be to enlarge small national markets by market integration, so that there was a bigger number of diverse market players.

Miriello and Polo (2015) analysed the evolution of natural gas hubs in Europe. They identified three steps in the process of market liberalisation. In the first stage, wholesale trade serves balancing needs only, then, when the market becomes more liquid, it can become an alternative source of LTCs. The last step includes hedging possibilities for traders, through the availability of financial instruments. They found that the Netherlands (TTF) and the UK (NBP) were the leaders in this process, while Germany and Italy may have lagged behind due to limited supply.

Heather and Petrovich (2017) agreed that there were two mature hubs in Europe, the Dutch TTF and the British NBP. The German exchanges (NCG and Gaspool) were significantly less developed, although more mature than the other hubs across Europe. They evaluated the maturity of a hub based on the number of market participants and traded products, traded volumes, the tradability index, and the churn rate. A similar categorization was made by EFET (2016), which concluded that on top of these, the French, Belgian and Italian exchanges could be considered as evolved in 2016.

According to MMR (2016), hubs based in the Czech Republic and Slovakia have become eligible for the inclusion in the advanced and emerging category, respectively. The report added, however, that there was still a considerable gap to high wholesale gas market liquidity across the whole of the EU, and most market areas were still some distance away from the indicative targets of the ACER Gas Target Model (AGTM), especially for forward liquidity associated metrics. Illiquid forward trading in large part of the EU was noted by Frontier (2016) as well.

Kantor (2017) found that illiquid hubs in the Baltics and the Central and Eastern European (CEE) region (BG, EE, EL, FI, HR, HU, LT, LV, PT, RO, SI, SK) were facing more fundamental problems than established and advanced hubs in Western Europe (NL, UK, AT, BE, DE, FR, IT): lack of political support to wholesale market development, lack of flexibility in the products offered, absence of an organised hub, and a lack of reference price were all factors hindering trade and development of wholesale gas markets in the Baltic and CEE countries.

Petrovich (2014) argued that in a well operating market structure - if the European market were really integrated – price correlation between neighbouring countries should be very high, indicating that there were no structural barriers of trade between them. Heather and Petrovich (2017) showed, however, that although Germany, Northern France, Belgium, and the Czech Republic indeed worked as a single price area, that area did not extend to Italy, Austria, and the Northern European countries; in fact, there were periods of de-linkage even in the British market.

The paper identified physical and non-physical barriers to trade which could be the cause of differing prices. Physical barriers included congested pipelines like the ones between Germany and Austria, or congestions within France. A more interesting case were the Italian-German situation, where no physical congestion appeared on the connecting route through Switzerland. ENI's long term capacity bookings, however, which were not released to the market when not used, created inefficient market outcomes. In the France-Spain relation there was no physical congestion either, but capacity was mainly booked on long term basis. The situation was similar between the Czech Republic and Poland. The analysis suggested that with the expansion of congested interconnectors and the proper implementation of the network codes, these problems were generally solvable.

The inefficient pricing and use of the transmission infrastructure was identified as a factor detrimental to the healthy functioning of the European gas market by many papers, including EWI (2016), Frontier (2016), CEPA (2016), and SUND (2016). According to Frontier (2016), obstacles remained in the primary and secondary trading of transport capacity, therefore the secondary markets for transmission capacity were illiquid in large parts of Europe. This could lead to suboptimal use of infrastructure: some infrastructure may be "overused", because the owners of capacity rights regard their cost as sunk.

CEPA (2016) and EWI (2016) argued that that the current system of entry and exit tariffs, charging full costs plus congestion fees for gas transits at the Intra-EU-interconnector points (IP), restricts competition in the EU internal gas market. According to CEPA's explanation, the result of full cost recovery is that transmission tariffs between entry-exit systems may be higher than efficient, reducing flows (and thus, market integration) below efficient levels. CEPA (2016) and Frontier (2016) observed that a stagnant or declining gas demand in the EU my put additional pressure on tariffs (as TSOs needed to recover their investment costs at lower gas flow levels), driving them even further from the optimal level.

The fact that transmission tariffs were too high and/or the methodology of calculating them was not transparent was given as the main barrier to trade by market participants themselves in Kantor (2017). Access to the cross-border transmission capacities was found to be hindered by administrative deficiencies: overpriced short-term capacities, insufficient amount of available interruptible capacities, ineffective use-it-or-lose-it (UIOLI) mechanisms, and complicated systems for the secondary trading of capacities. Market participants suspecting cross-subsidy in transmission tariffs demanded a thorough review of tariff setting methodologies by the European Commission.

As Kantor (2017) observed, however, long-term legacy capacity (LTLC) reservations raised complicated problems: on the one hand, in the absence of firm day-ahead UIOLI mechanisms, these contracts are considered a major barrier to access to transmission capacities. On the other hand, the failure to deal with these stranded contracts in a "proper way" raise serious doubts about shippers' intentions to enter into long-term capacity commitments in the future, making the financing of new interconnection capacities uncertain.

Tariff issues were also identified by ACER as barriers to the efficient co-operation of the gas and power sectors, and to the efficient use of storage. ACER (2014) stressed that national gas network tariff structures must not distort market signals that indicate when it is efficient for individual gas power plants to run. ACER (2015) observed that transportation tariffs in some Member States were based on maximum demand within a given month, which could dis-incentivise generation in the latter part of the month if the plant has not already generated in that month. It noted that in some MSs, gas-fired power generators were exposed to imbalance payments but faced unnecessary difficulties assessing current imbalance costs owing to a lack of transparency regarding the imbalance status of the total gas system.

ACER (2015) added that tariffs related to the use of storage and the bundling of storage products often inhibited the efficient use of storage for flexibility. As a more general remark on storage, MMR (2016) observed that storage-related regulations hindered market entry in some MSs. Modelling by REKK (2017) pointed to the inefficiencies related to storage obligations, which were in some cases hindering cross border use of storage and worsened the business case for other countries' storage facilities where no storage obligations existed.

EWI (2016) observed that higher transit charges may have a negative effect on competition by protecting high market concentration on the supply side in certain market zones, while the highly concentrated nature of upstream and wholesale markets, low contestability of captive markets - especially in Central and South-East Europe – were cited among inefficiencies by e.g., Frontier (2016), and CEPA (2016), among others. Dickel et al (2014) argued that the high level of dependence on Russian gas could be an obstacle to efficient natural gas markets in Europe, due to security of supply and market power issues. The study highlighted that this problem was more relevant in the Eastern, Balkan and Baltic states with less alternative supply options.

As far as exporters' market power was concerned, however, DNV KEMA (2013) did not find proof for (soft) manipulation of market or evidence that this could be the case in the future. The study therefore concluded that large exporters moving downstream would most likely have a positive effect on competition as they would bring further diversification, provided their market shares in the downstream market remained modest. Hulshof et al (2016) also concluded that changes in the supply side concentration did not affect gas prices. It must be noted, however, that their analysis was based on the development of the day-ahead spot TTF price (between 2011 and 2014), and their results may hardly be extrapolated to countries with less developed hubs.

ACER (2015) observed that 13 Member States did not meet the target of a Residual Supply Index (RSI) exceeding 110% of demand, and even countries with an RSI above 110% may not be immune to Security of Supply problems if they had interconnection capacities between them but depended on gas from the same source. Although LNG import capacities contributed to Security of Supply, pipeline capacities limited the geographical area in which LNG could be used, and high prices in Asia prevented LNG from putting competitive pressure on the prices of pipeline suppliers. ACER (2015) argued that even if LNG became more competitive in Europe – as it has indeed happened since the publication of AGTM – several Member States would not benefit because of transportation constraints and costs faced by shippers within Europe; a reasoning similar to EWI (2016).

The fact that LNG terminals are not fully connected to adjacent markets was cited among inefficiencies by Baringa (2016) as well. Modelling by REKK (2017) confirmed that LNG had limited contribution to mitigate supply disruptions in South-East Europe (SEE), as interconnectivity was still low in the Balkans (from the LNG terminal in Greece) and the planned LNG terminal in Croatia would need to reduce its planned regasification tariffs and the existing tariff on cross border interconnectors to be able to benefit the region.

MMR (2015) noted that even a high level of diversity of geographical origins of supply did not necessarily imply fierce competition at company level on wholesale gas markets of MSs. This is because a sole company could source its gas from distinct geographical origins and at the same time face no external competition from other companies. The AGTM metrics of HHI (designed to examine competition at company level in the upstream market) showed even higher values (i.e., higher concentration) in 2015 compared to 2011.

This may be the result of demand decline in recent years combined with the obligation to honour legacy long-term gas supply contracts, and – in the case of the Mediterranean region - a comparative decline in LNG sourcing volumes. MMR (2015) observed that higher import prices were primarily linked to dependence on fewer supply sources, mainly Russia, but – among other factors -, also to the overall reduced competition along the gas value chain. Market power issues may have therefore contributed to the fact that the Baltic and SSE regions continued to have some of the highest import prices in the EU. MMR (2016) also identified pockets of regional gas markets that still exhibited insufficient levels of interconnectivity; in Member States where the RSI was below the threshold and those with a unique or dominant source, the largest supplier could exert market power over price formation.

This issue was investigated by the European Commission during its probe into Gazprom's behaviour in CEE, resulting in filing antitrust charges against the company. The underlying concerns of the Commission focused on illegal partitioning of EU markets via territorial restriction and destination clauses, denial of third-party access to gas infrastructure, and imposing unfair prices on customers in CEE. These contractual measures created significant barriers to trade in the CEE region and prevented the integration of gas markets.[166]

Krzykowski and Krzykowska (2017) analysed another case related to Gazprom's market power in Europe: the effect of exempting the OPAL gas pipeline from third-party access rules. The authors underlined that the liquidity of the gas market was dependent on outside supplies, thus giving the opportunity to an already dominant market player of strengthening its position might distort the market. They claimed that the exemption of the pipeline from third party access rules may have a negative impact on gas supplies to some countries of the CEE region. It risks changing the current gas supply routes through Poland and Slovakia, worsening their negotiating positions with Gazprom.

[166] For a detailed analysis of the commitments made by Gazprom to settle the case, see: Jonathan Stern and Katjy Yafimava (2017): The EU Competition investigation of Gazprom's sales in central and eastern Europe: a detailed analysis and the way forward. (July 2017, Oxford Institute for Energy Studies).

ANNEX 4: THE BRIEF HISTORY AND MAJOR FEATURES OF LEGACY LTCS AND THE CONCLUSIONS OF THEIR RECENT RENEGOTIATIONS

The dominance of oil-indexed pricing[167] in legacy commodity LTCs has contributed to the margin EU customers have paid over US gas prices in the last decade. However, the implementation of a competitive market design has fundamentally transformed the contractual structure underlying the European gas market in the last five years.

In the followings we provide a brief review of the transition of pipeline related legacy long-term gas sales and purchase contracts through renegotiations and initial re-contracting in recent years.

The role and structure of legacy LTCs

Until the end of the 2000s, natural gas trading in continental Europe had been built on long-term gas sales and purchase contracts between major outside gas suppliers and European buyers.[168] The duration of these legacy contracts reflected the time needed to recover pipeline investments to deliver gas to the EU (originally up to 40 years, later 20-25 years). The contract included the volume of gas sales over the entire contract duration as well as the annual contracted quantity (ACQ) of gas. Russian contracts provided for sales volume guarantee in the form of a take-or-pay (ToP) obligation for the ACQ and volume flexibility for the buyer of typically ± 15% of ACQ. The pricing formula was the netback market value to the cheapest alternative, typically oil products. Contracts contained a price review option only once in every three years. Arbitration was allowed if parties failed to agree to a new price level following a price review.

Historical contracts have a point of delivery at a border point, because virtual trading points or hubs did not exist yet at the time of contracting. The delivery border was usually chosen to be close to the target market, but to allow for some delivery flexibility for the producer. This feature of the LTCs implied that commodity LTCs were coupled with transmission capacity LTCs covering the gas transportation route from the EU border entry to the delivery IP.[169] Destination clauses prohibited the resale of LTC gas, and thus allowed for price discrimination for the seller.

LTCs are best understood as risk mitigation tools in an industry with high sunk investment costs (Neumann et al, 2015). In the natural gas industry, LTCs put the principal price risk on the seller, while oil-indexation gives buyers long-term protection against prices exceeding those of the main competing fuels. The principal volume risk is on the buyer, while flexibility (ToP) clauses help to relax this risk.

Legacy LTCs were largely compatible with the EU's gas market and regulatory environment predating the Third Energy Package of 2009.[170] This market was built on vertically integrated national incumbent companies and no or limited competition for non-captive customers. Developing gas hubs were still illiquid and there was a lack of price transparency. Cross-border gas trading faced physical and contractual congestions, while significant national price differentials existed, especially between North-West and Central Eastern Europe.

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[167] We use the term 'oil-indexed pricing' as equivalent to Oil-price Escalation (OPE) pricing and 'hub-based pricing' as equivalent to Gas-on-Gas (GOG) pricing, applied by the IGU.

[168] For a review, see Chapters 2 and 4 of Stern (2012).

[169] Commodity LTCs are agreements between a buyer and a seller concerning the exchange of a commodity (gas), while capacity LTCs are 'long-term services' offered by the transmission system operator with a duration of one year or more.

[170] However, due to their incompatibility with the gradual gas market liberalisation and integration process in the EU, Gazprom agreed with the Commission to erase the destination clauses, prohibiting the re-export of LTC gas, from its contracts with West European partners (OMV, ENI, E.ON and GDF) already in 2003.

Changes in the economic environment in Europe leading to contract renegotiations

Oil price has long been and still is a major factor in determining EU natural gas wholesale prices. Figure 65 illustrates the major supply and demand side shocks that determined crude oil price development between 2006 and 2016.

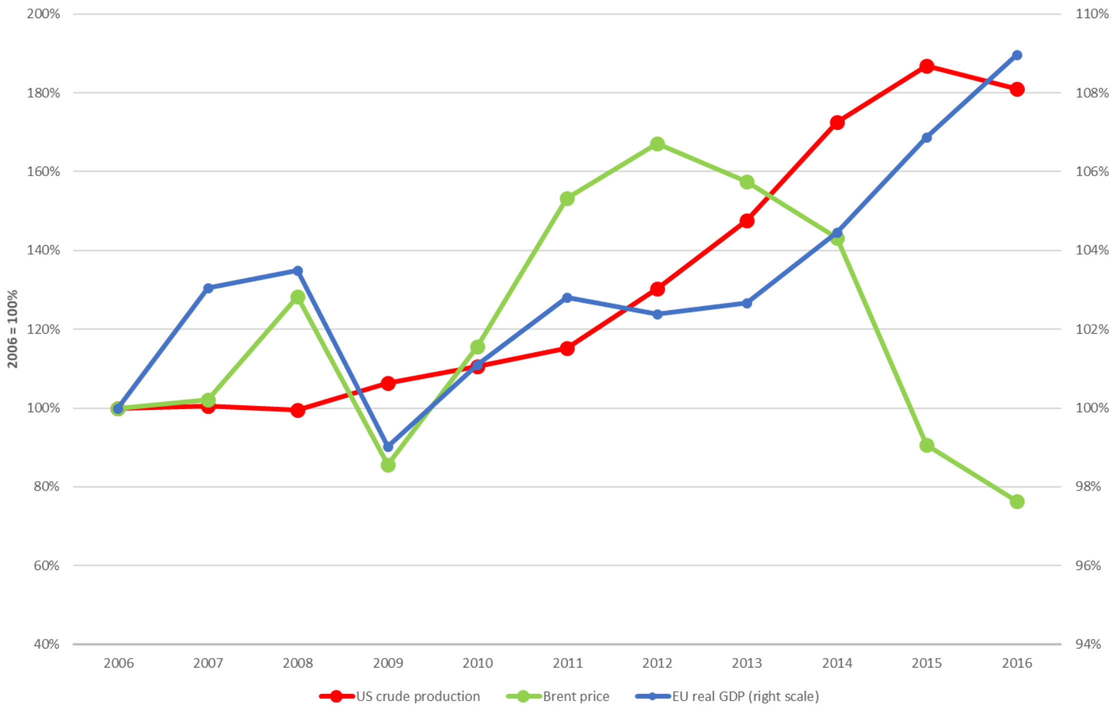

Figure 65: EU GDP, US oil production and Brent price dynamics, % (2006=100%)

Source: REKK analysis using BP Statistical Review of World Energy, Eurostat

The global (including the EU) economy experienced a sharp fall in 2009 and then a gradual recovery. In 2011, the EU GDP already exceeded its 2008 level. Between 2009 and 2012, economic growth helped oil price recovery after its free fall of almost 40% in 2009. However, since 2012 oil price dynamics have changed fundamentally due to the supply shock brought about by fast increasing US oil production[171] and the related breakdown of OPEC production agreements. Global economic growth and the related gradual demand growth could not offset this dramatic supply side effect. The Brent price fell by 54% between 2012 and 2016.

Figure 66 depicts the relationship between the dynamics of oil and natural gas prices in the EU. One conclusion from this comparison is that both LTC and hub price developments have followed oil price dynamics between 2006 and 2016. Oil-indexed pricing can apparently explain this phenomenon for legacy commodity LTCs. Compared to their top level in 2012, LTC gas prices fell 60% by 2016.

[171] The US increased its oil production by almost 90% between 2008 and 2015.

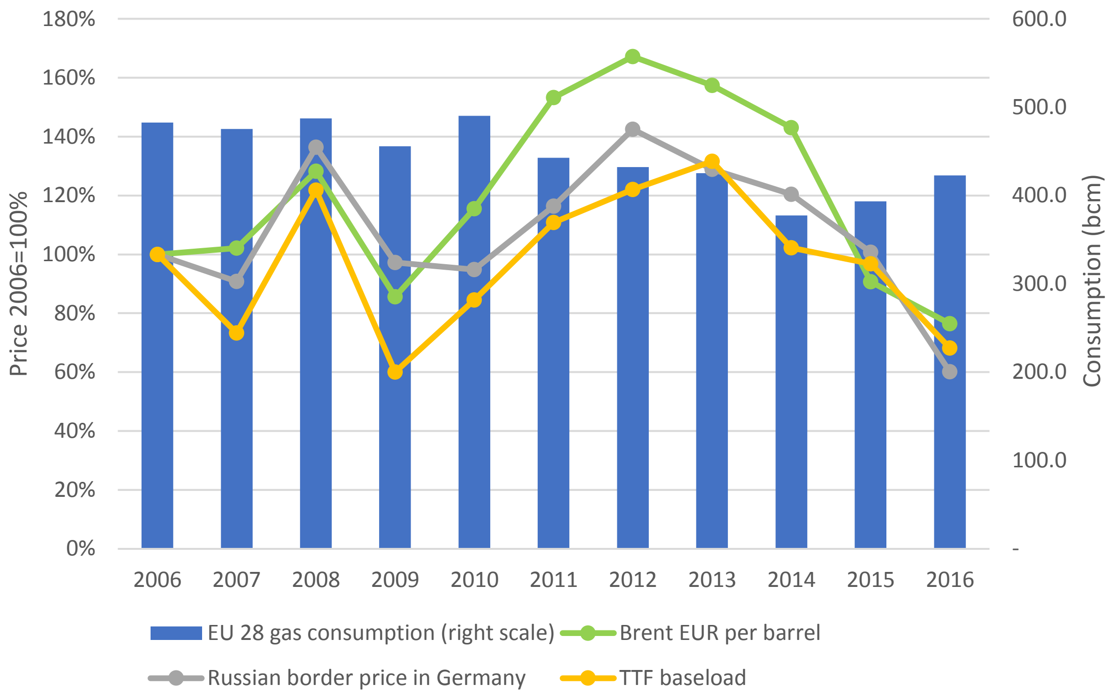

Figure 66: Brent, EU demand, LTC and spot gas price dynamics, (2006=100%)

Source: REKK analysis using BP Statistical Review of World Energy, Eurostat

For hub pricing (TTF), the impact of oil price dynamics can work through both supply and demand side effects.

EU gas demand remained weak despite recovering economic growth after 2009. By 2014, gas demand was 22% below its 2008 level, and the demand recovery in 2015 and 2016 resulted in EU demand still 13% below the 2008 level. As the pre-2009 gas demand forecasts turned out to be overly optimistic, LTC holder midstreamers got over-contracted and forced to sell their (originally oil-indexed) excess LTC gas to hubs. This boosted hub liquidity and put a downward pressure on hub prices.

In the last nine years, annual average LTC prices have always exceeded hub prices. The difference was largest in 2009 and 2012 but reduced close to zero by 2016.

While the early 2010s brought a prolonged deviation in TTF and oil-indexed LTC prices, they continue to be interlinked in the longer run as long as the price of the marginal supply remains to be oil-indexed. If there are ongoing LTCs where the take-or pay obligation is non-binding, the holders of oil-indexed contracts can provide or withdraw an additional unit of gas if hub prices deviate from that of the LTC.

In addition, LNG supply is also dependent on oil prices as it determines the opportunity cost of selling LNG to Europe versus Asia and other markets. Growing oil prices increase the predominantly oil-indexed LNG prices in Asia and makes the EU less attractive to supply and vice versa. Between 2009 and 2013, increasing oil prices and the rapid growth in Asian gas demand increased the attractiveness of the Asian market for LNG as compared to the EU. A decline in LNG supply supported the recovery in European hub prices. Since 2014, collapsing oil prices, the stepwise recommissioning of the nuclear power plants shut down after the Fukushima disaster and new LNG supplies from the US and Australia increased the attractiveness of the EU market again for LNG and put increased competitive pressure on pipeline gas suppliers. Increased pipeline – LNG competition has recently resulted in falling hub prices in the EU. Compared to their top level in 2013, hub prices decreased by 48% from their top level in 2013 by 2016.

Contract renegotiations and new contracts between 2009-2017

Legacy LTCs had several features that turned out to be disadvantageous for the buyers after the outbreak of the post-2008 economic crisis. Take-or-pay (ToP) obligations became binding when EU demand collapsed, and the contractual prices were persistently higher than falling market prices. While the contract terms secured minimum offtake and predictable revenue for the producers for many years ahead, it caused unbearable losses and heightened balance sheet risks for the LTC holders. It made the situation unsustainable for both parties and part of the losses of LTC holders were reclaimed in bilateral negotiations, price review proceedings or litigations.

The big European gas utility companies started to renegotiate their oil-indexed contracts with Gazprom, Statoil and Sonatrach at the beginning of 2010 (see Table 90). Renegotiations resulted in temporary or structural changes in LTC conditions including immediate price cuts, the direct or indirect introduction of spot-price indexation into the wholesale price formula, increased (downward) flexibility (except for Statoil and LNG contracts) and the reduction in offtake (e.g., Sonatrach exports to Italy and Spain) (Franza, 2014).

Country	Company	2009	2010	2011	2012	2013	2014
Austria	Centrex		+		+		+
Austria	EconGas OMV		+		+	+	
Austria	Erdgas Import Salzburg				+		
Austria	Gazprom Austria (GWH Gashandel)		+		+		+
Bulgaria	Bulgargaz	+				+	
Czech Republic	RWE Transgaz (RWE Supply & Trading)					+	+
Czech Republic	Vemex s.r.o.				+		
Denmark	DONG				+		
Estonia	Eesti Gaas AS			+			
France	GDF Suez		+	+		+	
Germany	E.ON		+		+		
Germany	Verbundnetz Gas AG			+			
Germany	WIEH		+	+			
Germany	Wingas		+	+			
Greece	DEPA			+			+
Hungary	Centrex Hungary Zrt.					+	
Hungary	Panrusgas Gas Trading Plc.					+	
Italy	Axpo Trading (EGL)		+		+		
Italy	Edison (Promgas)			+			
Italy	ENI		+		+	+	+
Italy	ERG		+				+
Italy	PremiumGas			+		+	
Italy	Sinergie Italiane		+	+		+	
Latvia	Latvijas Gaze			+			
Lithuania	Lietuvos Dujos						+
Netherlands	Gas Terra		+		+		
Poland	PGNiG				+		
Slovakia	SPP			+			+
Serbia	Srbijagas			+			+
Turkey	Botas	+		+			
Turkey	Akfel Gaz, Avrasya Gaz, Bosphorus Gas, Bati Hatti, Kibar Enerji, Enerco Enerji, Shell Enerji A.S.						+
	Shell Energy Europe				+		
	Renegotiated contracts (by years)	**2**	**12**	**13**	**12**	**9**	**10**
+	Contract renegotiated according to Gazprom data						
+	Discount made (inc. Discount that is made without amendment to contract) according to Gazprom official statements or media						

Note: Further contract renegotiations between Gazprom and its partners occurred in 2015 in Hungary and in 2016 in Germany, Estonia and Greece

Table 90: Renegotiated Gazprom contracts, 2009-14

Source: Mitrova (2015)

As the examples of ENI in Italy, Engie (formerly GdF) in France or Uniper (formerly E.ON) or RWE in Germany[172] show, suppliers have long been successful in adjusting long-term contracts with producers/importers towards current market conditions. A similar tendency with smaller suppliers and midstreamers can also be observed, such as the SPP in Slovakia, Latvijas Gāze in Latvia or even Polish PiGNIG's considerations of not prolonging the current commodity LTC.[173] If producers want to secure long-term delivery contracts as hedge for their long-term production and investments, they must adapt to the new market conditions in the EU.

In North-West Europe, the wave of contract renegotiations between 2010 and 2014 resulted in a fast narrowing gap between LTC and hub prices. According to IGU (2016), gas-on-gas (GOG) price formation was underlying 90% of gas trade transactions already in 2014 due to increased hub trading and the introduction of hub indexation into LTCs, and has remained at that level since then.

Although being slower, gas pricing transformation is also underway in CEE, the Baltics and – to a smaller extent – in South-East Europe. In CEE, GOG pricing grew from almost zero in 2009 to 58% in 2016 (IGU, 2017) and became the dominant driver of price formation aside from oil-indexation. However, oil-indexation remained the dominant gas price determinant for the Baltic and SEE countries until very recently (Wachsmuth et. al, 2017).

While legacy LTCs started to expire all around Europe, the experience on what happens after a legacy contract expires is also accumulating.

On newly signed contracts, Franza (2014) concludes that the trend is towards shorter commitments (from 20-25 to 10-15 years) except for the 25-year contract between European buyers and Azerbaijan in 2013 needed to finance the TANAP-TAP pipeline investment.

The box below summarises recent experiences with concluding new contracts in CEE.

Recent experiences with new contracts in CEE

Bulgaria contracted for 10 years with Gazprom in 2012, a significantly shorter duration than before. The ACQ in the new contract (2.9 bcm/a) is 0.4 bcm higher than before and almost completely covers Bulgaria's 2016 gas consumption (3 bcm). However, the Bulgarian government intends to diversify supply sources after 2022 by procuring gas from the TAP pipeline via the Interconnector Greece Bulgaria (ICGB). At the end of 2016, ICGB ran a successful market test for the planned 3 bcm pipeline and will start construction tendering by the end of 2017.

Croatia: When its legacy Russian contract expired in 2010, INA, the dominant local gas wholesaler, decided to launch a tender for procuring gas to supply Croatian customers. ENI won the right of supply for three years. Between 2013 and 2017, INA supplied the Croatian market without a long-term contract. In the second half of 2017, Gazprom concluded a 10-year contract of 1 bcm ACQ with its local private partner PPD.

[172] https://www.engie.com/en/journalists/press-releases/gazprom-price-gas/

https://www.engie.com/en/journalists/press-releases/statoil-gas-supply-contracts/

https://www.eon.com/en/about-us/media/press-release/2016/agreement-reached-with-gazprom-on-price-adjustments-to-long-term-gas-supply-contracts.html

https://www.eni.com/en_IT/media/2016/12/eni-and-sonatrach-reached-an-agreement-on-gas-supplies

[173] http://uk.reuters.com/article/us-eeurope-summit/poland-aims-to-end-long-term-gas-supplies-from-russia-after-2022-idUKKCN0YM2QJ

Hungary: When its legacy contract expired in 2015, Gazprom offered to "prolong" the offtake of the non-consumed 21 bcm ToP quantity, accumulated until the end of 2015, with very high flexibility and at TTF-linked prices. A Memorandum of Understanding was also signed to engage in a new contract after 2021, although contractual volumes haven't been discussed yet. So far, due to competitive pricing, Gazprom could keep its former market share by selling 5.54 bcm (62% of its consumption) in 2016. Hungary could manage to get these favourable conditions from Gazprom by heavily investing in infrastructure diversification prior to 2015.

Estonia: Eesti Gaas, the main gas importer, entered into a 3-year contract with Gazprom after its legacy contract expired in January 2016, and at the same time started to import LNG from Lithuania. Unused gas from the former ToP is assumed to have moved into the new contract. The duration of this contract is a third of the former one.

Lithuania: Continued without a new contract when its legacy contract expired with Gazprom at the end of 2015. More recently, Lithuanian state-owned LITGAS contracted with Gazprom for one year (2017) for one third of its consumption.

ANNEX 5: GAS MARKET MODELLING FOR THE QUO VADIS PROJECT, 26 JULY, BUDAPEST, HUNGARY

Memo on the Q&A session of the Workshop

Summary

During the workshop, the European Gas Market Model (EGMM) was introduced to the audience in detail. Related presentations and background material are available here: http://rekk.hu/event/149/gas_market_modelling_for_the_quo_vadis_project
Assumptions on reference scenario building were discussed and generally not questioned. The importance of LTC assumptions and the need for demand and supply sensitivities were stressed. Stakeholders expressed their need for transparency on infrastructure assumptions to be used in the Reference Scenario. The further possibility to comment on the modelling workshop will be announced by EC.
Beyond modelling issues questions were related to TCF and TSO revenue neutrality and cost assumptions on the different alternative scenarios. These questions were not addressed in detail but notes were taken on comments.
Below is a summary of the most relevant Q&As raised during the workshop. Please note that this is a consolidated summary based on Chatham House rules.

Q&A

General

Q: What is backhaul?
A: Possibility for virtual trade on existing pipelines against the main direction of LTC contracted gas.

Q: How do you represent interruptible capacities in your model?
A: We use only firm technical capacities.

Q: Modelled and actual market share data seem to slightly differ for the 2016 calibration of the EGMM. What have you learnt from this calibration exercise?
A: The modelled market share of Russian supply was indeed slightly lower than the actual share. We attribute this to flexible demand and/or the make-up deliveries in 2016 of some LTC contracts that are not reflected here as this is a yearly model.

Q: Is the external price for Asian markets fixed?
A: Yes, it is fixed but different for each modelled month.

Q: Are consecutive months modelled sequentially or simultaneously?
A: Simultaneously.

Q: How accurate is the model on a monthly level? Can you publish monthly figures?
A: We can, but the model performs better on annual level and monthly results are less accurate.

Q: You need sensitivities of LTC supply – what if all LTCs will disappear?
A: Sensitivities will be conducted at least for NS2, demand, LNG and LTC supply.

Q: What demand scenario are you using for the reference?
A: EUCO30 and PRIMES reference. They provide the same forecast for 2020.

Q: There is insufficient attention paid for the problems of the CEE region. The problem of Russian supply dominance is not sufficiently addressed.
A: This is an EU project and all regions are considered with the same attention. The model optimises for the overall European gas market. Russian supply dominance in CEE is reflected by normally higher priced LTC contracts in this region. Price of LTCs used in the model is based on foreign trade statistics.

Q: How Switzerland is considered in this exercise? Are Swiss IPs considered as they had intra-EU tariffs or are they handled as EU external border points, relevant for TCF revenue collection?
A: Not yet decided. Currently Switzerland is part of the modelling, but Swiss welfare change is not accounted for in EU28 welfare calculations. Thanks to its unique position we tend to think that Swiss IPs are better to handle as if they had intra-EU tariffs.

Q: How is the Energy Community considered in this study? Can we receive the results regarding EnC contracting parties?
A: EnC contracting parties are endogenous in the model, but we do not take their welfare into account in the analysis. For these countries, we use the same demand outlook as in the PECI report. We are open to update the data. We have the output for the EU-EnC CPs but it is up to the EC to decide about the use of this data.

Q: What kind of modelling outputs can we expect? On what timescale do you consider the effects of e.g., the tariff scenario?
A: We plan to provide at least for welfare changes for each stakeholder group for every modelled country. Timescale is typically one year.

Q: Do you see any possibility to transport LTC gas inside the EU more efficiently than now?
A: We do not exclude this possibility.

Q: How do you measure liquidity and the possible effects of a tariff reform on liquidity? What indicators do you use?
A: We do not apply liquidity measures.

Storage

Q: How are Gazprom storages considered?
A: Gazprom storages are providing flexibility for the Russian long-term contracts. For the Bergermeer storage half of the capacity is offered to the market.

Q: Do you apply extrinsic value of storage? It seems that only intrinsic value is considered.
A: Only intrinsic value is used.

LNG

Q: LNG market representation seems too simplistic in the model. How are re-exports considered?
A: There is no option to re-export in the model, all terminals receive only. It can be interpreted as net receive, re-export deducted.

Q: Will there be sensitivity tests for LNG supply?
A: Yes.

Reference infrastructure

Q: Is the assumption of Nord Stream 2 commissioning and its inclusion into the Reference Scenario coming from the Commission or reflecting REKK's view?

A: It is not decided yet what new infrastructure shall be included into the Reference Scenario. The Commission will decide on this matter and the Final Report will contain full information on projects in the Reference. The inclusion of NS2 into the Reference can be based on the FID status of the project in the TYNDP. Whether it will be part of Reference for this project or not, a sensitivity run on infrastructure will be useful, as NS2 is a key and politically sensitive project.
Comment: Gazprom will transit 30 bcm via Ukraine after commissioning Nord Stream 2 and rerouting major contracts.

Q: How do you consider TAP in the Tariff Reform Scenario? Is there one entry or two entries to Europe?
A: We assume one entry at the TR-GR border.

Capacity booking, UIOLI

Q: Is Use it Or Lose it implemented in the model?
A: Yes, model assumes perfect implementation of the UIOLI principle. Capacity use is associated with physical gas flows.

Q: How are capacity bookings handled?
A: EGMM models flows and assumes that bookings are optimal for those flows.

Q: How would you avoid capacity hoarding if the IP tariff is 0? Why not everyone would buy endless capacity and keep them in the fridge?
A: Capacity hoarding is not possible in the model; a perfect implementation of the UIOLI principle is assumed.

TSO assets, revenues, stranded assets

Q: In several EU Member States revenue cap regulation constrains TSO revenues and excess revenues are "given back" to consumers. How is this considered in modelling?
A: TSO revenue regulation is a national issue on which we do not have detailed information. We propose to focus on quantifying the total amount of TSO revenues and then to apply *revenue neutrality* in the QV simulations, meaning that the overall revenue of the TSOs are kept at the Reference scenario (or 2016) level when running the Regulatory scenarios. While we understand that significant changes in the utilisation of transmission assets under certain regulatory scenarios might call for the revision of the TSO's revenue requirement, we also understand this issue is out of scope for this study.

Q: Do you consider DSO assets as well or only TSO assets?
A: We consider only TSOs in the modelling.

Q: TSO definition is fluid - in some countries it means a pure transit, in other cases it owns part of a distribution network. How do you control for that? How do you define a "fair" TSO asset base?
A: We assume that the issue of a fair TSO asset base definition is supervised by NRAs, who incorporate into a TSO only relevant TSO assets. Further, we assume any DSO-like assets would be attached to local customer needs and not linked with transit infrastructure and fees.

Q: Do you assume that flow*tariff = TSO revenue? This is not the reality since TSO revenues are based on assets.
A: Yes, but regulated tariffs should allow exactly for the recovery of TSO justified costs including asset related capital costs plus O&M. In the model, we convert capacity-based tariffs to flow-based tariffs and assume that this allows for a good representation of reality.

Q: How will you consider TSO asset base and stranded assets?

A: A change in the level of asset utilisation due to the implementation of certain regulatory scenarios will indicate the risk of certain assets becoming potentially stranded. General approach of how to handle the issue of stranded assets will be outlined.

Transmission tariffs, EU entry tariffs, TCF

Q: Does the model include domestic exit tariffs?
A: Yes, domestic exit tariffs from transmission to the distribution system are included. Distribution sector is not modelled.

Q: If we put all tariff on domestic exits and on LNG entry points, this will raise the marginal price in Europe and possibly increase the cost of gas on the European market. We should not handle LNG the same way as pipeline imports.
A: We do not propose to discriminate against pipeline gas in favour of LNG.

Q: For transmission tariff calculation, an average 56.2% utilisation of booked capacities is assumed. Why? For 2020 it may be 100%!
A: This assumption is based on the most recent ACER assessment of transmission capacity utilisation (2016 Market Monitoring Report, weighted average). We consulted the ENTSOG transparency platform but data was insufficient and not published for all IPs. We prefer to use the average to help tariff comparability. A higher utilisation of shorter term bookings by 2020 might result in similar tariffs calculated by assuming lower utilisation of yearly bookings.

Q: If booked capacity usage ratio is 56% it means that 44% of the capacity booking costs are sunk for the traders. Do you think a higher capacity utilisation level would modify their behaviour?
A: In the model, we do not represent capacity booking behaviour. The capacity utilisation ratio is only used for transforming diverse capacity and energy based tariff schemes into standardized, comparable EUR/MWh based IP tariffs. Thus, we do not expect a behavioural change in our model. However, the spread of more efficient and shorter-term capacity utilisation might impact TSO revenues.

Q: Adding a uniform x to every tariff on the EU entry points rather socializes the costs related to shipping gas to downstream markets instead of considering the differences in costs related to supply different markets (e.g., how far from a given entry point the gas molecules travel later). What about bottlenecks inside the system?
A: The entry-exit tariff system is fundamentally unrelated to transportation routes. We think uniform EU entry tariffs would distort more the internal gas market than applying an additive uniform x. This is like applying an "excise duty" logic.

Q: We don't need the regulation to be fair at this point, we just want to see what happens if we do this or that. Why not to check every possible EU entry tariff combinations?
A: This approach is unfortunately technically not possible.

Q: …then choose the extremes, and see what happens at the edges.
A: Yes, this is our usual approach

Q: Why do you assume that transmission tariffs are to decrease by 2020? New investments will likely to be financed, this would indicate an increase in tariffs.
A: We have seen IP tariff decreases all around in the last year. We have received comments suggesting both increase and decrease of tariff level by 2020. Our assumption for 2020 is that IP tariffs will remain at the current (2016) level and only outlier (mean well above average) tariffs will be cut back to close to average levels.

Q: How will outlier tariffs be cut back? Depending on the utilisation rate or flows?

A: Outliers above a certain threshold in excess of EU average or regional tariff levels are cut back, only tariff level matters…

Q: …but lower tariffs will never generate enough income to recover IP costs.
A: We assume an inverse relationship between IP tariffs and utilisation rate.

Q: How do you foresee the operation of the TCF? How is this included in the modelling?
A: TCF operation should be as simple as possible. The Fund should collect part or full of the lost TSO revenues due to cutting IP tariffs to zero in the Tariff Reform Scenario from EU entry tariffs. We foresee no inter-TSO payments, only payments between the Fund manager and the individual TSOs. There is an implicit assumption that the regulated revenue of all TSOs is fair at present. The impact of the proposed TCF scheme on the cost efficiency incentives of TSOs should be carefully analysed.

Market merger

Q: What is the difference between conditional market merger and full market merger?
A: Conditional market merger could be modelled as a Tariff Reform Scenario in a limited set of countries.

Q: How do you select regions for the Market Merger Scenarios?
A: We have two options. We merge countries where there is no congestion on the IPs and/or we merge zones where there is strong existing cooperation among Member States.

Q: How will the cost of marker mergers be accounted for through the analyses? Would it be possible to get information on market merger costs from TSOs? We observe preliminary cost estimates to double and commissioning times being delayed compared to original plans.
A: Modelling will only provide social benefit estimates. This can later be contrasted to available merger cost estimates analyses.

Q: What about the influence of zone mergers on neighbouring countries?
A: This will be one of the results of the modelling.

Welfare analysis

Q: If a higher tariff is put on the EU border entry points, the commodity price may increase for EU consumers. Are you considering welfare for all EU28 or only some countries?
A: We optimise combined EU28 welfare, but the welfare impact for individual countries will be also part of the modelling result.

Q: If we evaluate regulatory scenarios based on EU28 overall welfare change, there will probably be losers and winners. What would the losers say? How can we make them to accept such regulation? What is your justification for this?
A: Welfare gains should exceed losses so that if the losers are fully compensated there should some benefit remain. The same principle is applied for cross border cost allocation rules regarding PCIs since there are always winners and losers in those cases either.

ANNEX 6: EGMM MODEL DESCRIPTION

The EGMM is a competitive, dynamic, multi-market equilibrium model for natural gas production, trade, storage, and consumption in Europe. It explicitly includes a supply-demand representation of 35 European countries,[174] as well as their gas storages and transportation links to each other and to the outside world. The time frame of the model is 12 consecutive months, starting in April. Market participants have perfect foresight over this period.

REKK's European Gas Market Model has been developed to simulate the operation of an international wholesale natural gas market in whole Europe. The next figure shows the geographical scope of the model. Country codes denote the countries for which we have explicitly included the demand and supply side of the local market, as well as gas storages. Large external markets, such as Russia, Iran, Libya, Algeria and LNG exporters are represented by exogenously assumed market prices, long-term supply contracts and physical connections to Europe.

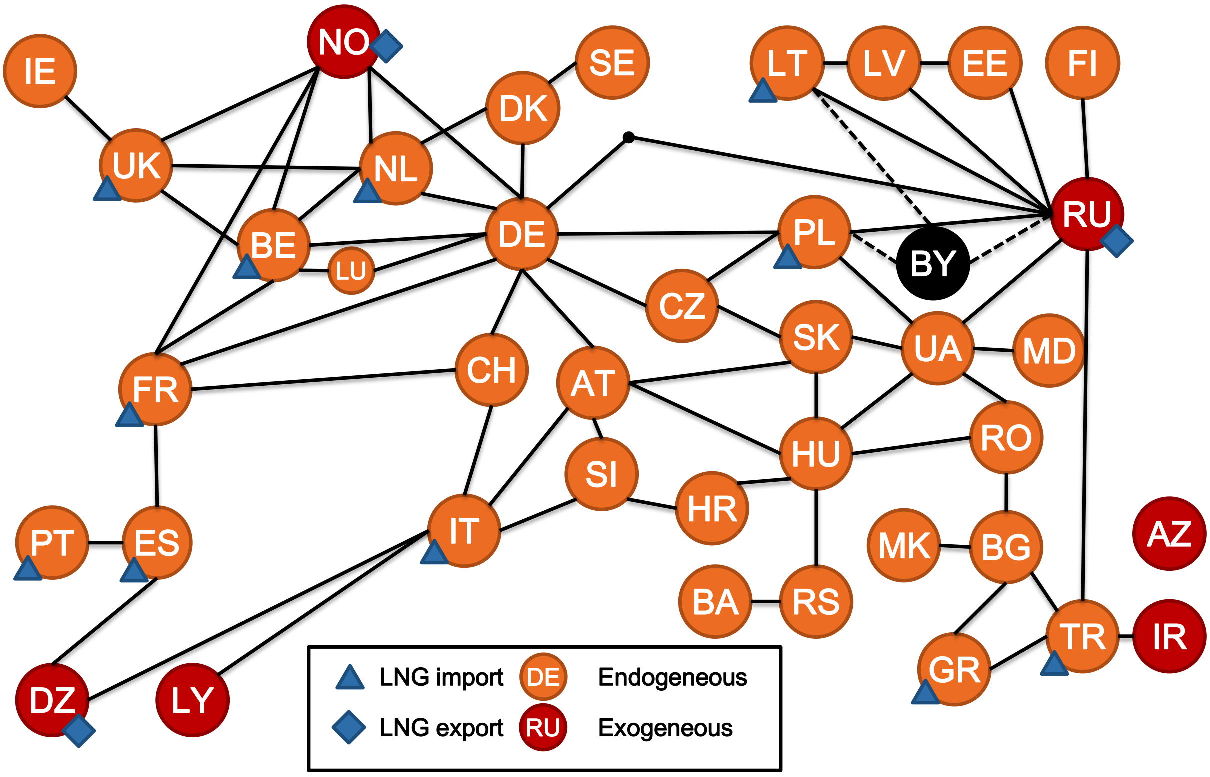

Figure 67. The geographical scope of the European Gas Market Model

Source: REKK

Given the input data, the model calculates a dynamic competitive market equilibrium for 35 European countries, and returns the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions and long-term contract deliveries.

Model calculations refer to 12 consecutive months, with a default setting of April-to-March.[175] Dynamic connections between months are introduced by the operation of gas storages ("you can only withdraw what you have injected previously") and take-or-pay (TOP) constraints (minimum and maximum deliveries are calculated over the entire 12-

[174] Countries covered are EU-27 (not including Cyprus), Energy Community Contracting Parties (Albania, Ukraine, Moldova, Serbia, FYR of Macedonia, Bosnia and Herzegovina), Switzerland and Turkey
[175] The start of the modeling year can be set to any other month.

month period, enabling contractual "make-up").The European Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) long-term take-or-pay (TOP) contracts; and (7) spot trading. We will describe each of them in detail below.

Local demand

Local *consumption* refers to the amount of gas consumed in each of the local markets in each month of the modelling year. It is, therefore, a quantity measure.[176] Local *demand*, on the other hand, is a functional relationship between the local market price and local consumption, similarly specified for each month of the modelling year.

Local demand functions are downward sloping, meaning that higher prices decrease the amount of gas that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example).

The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.

Local supply

Local *production* is a similar quantity measure as local consumption, so the corresponding counterpart to local demand is local *supply*. Local supply shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price.

In the model, each supply unit (company, field, or even well) has either a constant, or a linearly increasing marginal cost of production (measured in €/MWh). Supply units operate between minimum and maximum production constraints in each month, and an overall yearly maximum capacity.[177]

Any number of supply units can be defined for each month and each local market. As a result, local supply is represented by an increasing, stepwise linear function for which the number, size, and slope of steps is defined by the user.

Gas storage facilities

Gas storages are capable of storing natural gas from one period to another, arbitraging away large market price differences across periods. Their effect on the system's supply-demand balance can be positive or negative, depending on whether gas is withdrawn from, or injected into, the storage. Each local market can contain any number of storage units (companies or fields).

Storage units have a constant marginal cost of injection and (separately) of withdrawal. In each month, there are upper limits on total injections and total withdrawals. Storage fees are considered in a volumetric manner, which considers injection, withdrawal and working gas tariff items.

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[176] All quantities are measured in energy units within the model.

[177] Minimum production levels can be set to zero. If minimum levels are set too high, a market clearing equilibrium may require negative prices, but this practically never happens with realistic input data.

There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.

External markets and supply sources

Prices for external markets and supply sources are set exogenously (i.e., as input data) for each month, and they are assumed not to be influenced by any supply-demand development in the local markets. In case of LNG, the price is derived from the forecasted Japanese spot gas price, taking into account the cost of transportation to any possible LNG import terminal. As a consequence, the price levels set for outside markets are important determinants of their trading direction with Europe. When prices of the external markets are set relatively low, European countries are more likely to import from the outside markets, and vice versa.

Cross-border pipelines

Any two markets (local or outside) can be connected by any number of pipelines or LNG routes, which allow the transportation of natural gas from one market to the other. Connections between geographically non-neighbouring countries are also possible, which corresponds to the presence of dedicated transit routes.

Cross-border linkages are unidirectional, but physical reverse flow can easily be allowed for by adding a parallel connection that “points” into the other direction. Each linkage has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee.

Virtual reverse flow (backhaul”) on unidirectional pipelines or LNG routes can also be allowed, or forbidden, separately for each connection and each month. The rationale for virtual reverse flow is the possibility to trade “against” the delivery of long-term take-or-pay contracts, by exploiting the fact that reducing a pre-arranged gas flow in the physical direction is the same commercial transaction as selling gas in the reverse direction.

Additional upper constraints can be placed on the sum of physical flows (or spot trading activity) of selected connections. This option is used, for example, to limit imports through LNG terminals, without specifying the source of the LNG shipment.

Furthermore, the model allows for constraining spot flows on infrastructure for interconnectors exempted / not under the jurisdiction of the European Regulation or booked long term by a major market player (e.g., Trans-Balkans pipeline).

LNG infrastructure

LNG infrastructure in the model consist of LNG liquefaction plants of exporting countries, LNG regasification plants of importing countries and the “virtual pipelines” connecting them. “Virtual pipelines” are needed to define for each possible transport route a specific transport price. LNG terminals capacity is aggregated for each country, which differs from the pipeline setup, where capacity constraints are set for all individual pipeline. LNG capacity constraints are set as a limit for the set of “virtual pipelines” pointing from all exporting countries to a given importing country, and as a limit on the set of pipelines pointing from all importing countries to a given exporting country.

Long-term take-or-pay (ToP) contracts

A take-or-pay contract is an agreement between an outside supply source and a local market concerning the delivery of natural gas into the latter. The structure of a ToP contract is the following:

Each contract has monthly and yearly minimum and maximum quantities, a delivery price, a point of delivery and a monthly proportional ToP-violation penalty. Maximum quantities (monthly or yearly) cannot be breached, and neither can the yearly minimum quantity. Deliveries can be reduced below the monthly minimum, in which case the monthly proportional ToP-violation penalty must be paid for the gas that was not delivered.

Any number of ToP-contracts can be in force between any two sources and destination markets. Monthly ToP-limits, prices, and penalties can be changed from one month to the next. Contract prices can be given exogenously, based on oil-indexed long-term contract formulae.

The delivery routes (the set of pipelines from source to destination) must be specified as input data for each contract. It is possible to divide the delivered quantities among several parallel routes in pre-determined proportions, and routes can also be changed from one month to the next. The point of delivery may be set to any interconnector within the modelled system.

Spot trading

The final building block, spot trading, serves to arbitrage price differences across markets that are connected with a pipeline or an LNG route. Typically, if the price on the source-side of the connection exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the connection is reached.

Physical flows on pipelines and LNG routes equal the sum of long-term deliveries and spot trading. When virtual reverse flow is allowed, spot trading can become "negative" (backhaul), meaning that transactions go against the predominant contractual flow. Of course, backhaul can never exceed the contractual flow of the connection.

Equilibrium

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above.

In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time.[178] However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders.[179]

[178] There is one, rather subtle, type of arbitrage which is treated as an externality, and hence not eliminated in the model. We assume that whenever long-term ToP contracts are (fully or partially) linked to an internal market price (such as the spot price in the Netherlands), the actors influencing that spot price have no regard to the effect of their behaviour on the pricing of the ToP contract. In particular, reference market prices are not distorted downwards in order to cut the cost of long-term gas supplies from outside countries.

[179] We leave out storage operators, since injection and withdrawal fees are set exogenously, and stock changes are determined by traders.

Local consumers decide about gas utilisation based on the market price. Consumers in each market within the region are represented by a linear monthly gas demand function that only depends on the contemporaneous local wholesale price of gas.

Local producers have piecewise linear short-run cost functions, with upper and lower limits on monthly production and a separate upper constraint on yearly output. Local producers decide about their gas production level in the following way: if market prices in their country of operation are higher than unit production costs, then they produce gas at full capacity. If prices fall below costs, then production is cut back to the minimum level (possibly zero). Finally, if prices and costs are exactly equal, then producers choose some amount between the minimum and maximum levels, which is actually determined in a way to match the local demand for gas in that month.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about long-term contract deliveries in each month, based on contractual constraints (prices, ToP quantities, penalties) and local supply-demand conditions. Importers own long-term take-or-pay (ToP) contracts that are sourced from gas exporters in outside markets, most importantly from Russia, Norway, Algeria, and a number of LNG exporting countries. Each contract specifies a price, a delivery route, and a minimum and maximum delivered quantity per month and per year. The monthly minimum delivery constraint alone is flexible: it can be violated, but most of the undelivered gas must be paid for according to the ToP rules.

Second, traders also utilize storages to arbitrage price differences across months. For example, if market prices in January are relatively high, then they withdraw gas from storage in January and inject it back in a later month in such a way as to maximize the difference between the selling and the buying price. As long as there is available withdrawal, injection and working gas capacity, as well as price differences between months exceeding the sum of injection costs, withdrawal costs, and the foregone interest, the arbitrage opportunity will be present and traders will exploit it.[180,181]

Finally, traders also perform spot transactions, based on prices in each local and outside market and the available cross-border transmission capacities to and from those markets, including countries such as Russia, Turkey, Libya, Algeria or LNG markets, which are not explicitly included in the supply-demand equalization.

Besides the actors listed above, the EGMM considers infrastructure operators as well. Transmission System Operators (TSOs), Storage System Operators (SSOs) and LNG operators however are not active actors within our modelling framework. The infrastructure operators merely observe the gas flows utilising their infrastructure and earn revenues based on the utilisation. Since all actors exhibit price-taking behaviour, the equilibrium is welfare-maximising for all market participants.

Welfare analysis

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual projects can bring to the analysed region. Total positive socio-economic welfare accounted for in the NPV of a modelled period (year) is calculated as the sum of welfare change of all market participants:

- Consumer surplus [to consumers]

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[180] Traders also have to make sure that storages are filled up to their pre-specified closing level at the end of the year, since we do not allow for year-to-year stock changes in the model.

[181] A similar intertemporal arbitrage can also be performed in markets without available storage capacity, as long as there are direct or indirect cross-border links to countries with gas storage capability. In this sense, flexibility services are truly international in the simulation.

- Producer surplus (or short-run profit, excluding fixed costs) [to producers]
- Profit on long-term take-or-pay contracts [to importers]
- Congestion revenue on cross-border spot trading [to TSOs]
- Cross-border transportation profit (excluding fixed costs) [to TSOs]
- Storage operation profit (excluding fixed costs) [to SSOs]
- Profit on inter-temporal arbitrage via gas storage [to traders]
- Profit of LNG operators [to LNG operators]

Welfare change for each market participant is assigned with an equal weight of 1:1.

For more details on the welfare concept and calculation inherent for the EGMM, see Section 2.6.

Major model outputs

For each modelled period EGMM produces equilibrium prices and quantities. For the present analysis the most important model outputs are wholesale gas prices per country, hub prices per country (wholesale prices plus domestic exit fee), consumption by country, gas flows on interconnectors, LNG inflow at regasification terminals (aggregated by country), storage stock change and import volumes through long term contracts and spot trade.

ANNEX 7: ASSUMED NEW INFRASTRUCTURE FOR THE 2020 MODELLING SCENARIOS

Name	Maximum flow (GWh/d)	Date of commissioning	Basis to include into reference for 2020
IT-CH	368	2018	FID
BG-RS	51	2018	FID
RS-BG	51	2018	FID
CH-FR	100	2018	FID
CH-DE	240	2018	FID
TR-GR_TAP	350	2019	FID
GR-MK_TAP	25	2019	FID
AZ-TR_TANAP	490	2018	FID
GR-BG	90	2018	FID
GR-BG	151	2021	FID
GR-IT_TAP	334	2019	FID
SI-HR	165	2019	FID
HR-SI	165	2019	FID
BG-RO	14	2016	FID
RO-BG	14	2016	FID
IT-AT	189	2018	FID
AT-DE	36	2017	FID
DE-AT	143	2017	FID
GR-LNG expansion	81	2017	FID
MT-LNG	24	2020	existing 2017
FI-EE	79	2020	FID according to project site
EE-FI	79	2020	FID according to project site

Table 91: New transmission infrastructure assumed for the 2020 reference scenarios based on ENTSOG TYNDP

Storage facility	Market	Capacity			Commissioning
		Working gas (TWh)	Injection (GWh/d)	Withdrawal (GWh/d)	
Tuz Gölü	TR	5	159	159	2017
Botas Tarsus	TR	11	319	319	2020
Silivri (Marmara)	TR	46	638	638	2020
Bordolano phase II	IT	7	109	185	2019

Table 92: New storage capacities assumed for the reference scenarios 2020

Source (both tables): REKK assumption based on ENTSOG TYNPD and GSE

ANNEX 8: DISCUSSION PAPERS AND STAKEHOLDER COMMENTARY

We summarise the main suggestions presented in the discussion papers by other tenderers and in the responses provided by stakeholders on the following table per topics (in case of stakeholder responses we also include the author of the suggestion / commentary). Suggestions marked with green have been directly reflected in the Quo vadis study, while yellow colour code indicates that the suggestion was taken into consideration.

Topic	Suggestion	Approach
EU welfare	Metrics of welfare gain of individual market participant groups (consider different importance of market players, customers welfare compared to producer/trader welfare)	
Market mergers	Not all zonal mergers are beneficial, some might lead to inefficient investment decisions	
	Political interest might stop some of the beneficial mergers	
	Larger bidding zone provides more liquidity and competition, but less transmission cost reflectivity	
	National regulators' objectives are not harmonized and NRAs apply different approaches	
	Current gas market is functioning, no large changes needed	
	Top-down solution could lead to an opposition from individual market participants, who would rather prefer bottom-up solutions	
Transmission tariffs	Transmission tariffs are designed for full cost recovery. Therefore, transport costs might be higher than efficient, reducing flows and thus market integration.	
	For efficient system utilisation only short term marginal costs and congestion costs should be charged at cross-border	
	Challenging cross-border tariffs would lead to big uncertainty	
	Ramsey pricing (price elasticity based cost allocation)	
	Exit (consumer end) / entry (EU border) charges would lead to increased competition, but reducing information about gas sources and actual cost of transmission (problematic redistribution costs to TSOs)	
	EU entry points used by highest cost suppliers can be charged less than entry points used by lower cost suppliers	

Topic	Suggestion	Approach
TSO revenues and ITC	TSOs reporting high profits, prices should be cost reflective and based on actual cost of efficient network operators, currently little attention paid to their efficiency	
	ACER should provide cost benchmarking and investigate what will be the transmission costs after depreciating the network	
	ITC mechanism to evaluate use of gas pipelines ex-post (annually) and determine monetary flows (example of Austria, but more complicated due to administrative, political and legal factors)	
Gas demand	Mostly stagnation / decline forecast, but higher flexibility due to back-up role needed (coordination between gas and electricity)	
	Uncertainty regarding future role of gas transmission and storage system (facilitating the large-scale storage of renewable power)	
	Declining gas consumption leads to "upward spiral effect on tariffs" which further leads to downward spiral effect on consumption	
	Gas price is not competitive	
Security of supply	EU-wide versus national approach	
	Role of LNG: not connected to one supplier, but price and supply volatility	
Other	Quantitative study might be hampered by lack of quality data, before NC properly implemented, not enough data available (author: oil and gas producers)	
	Governance issues (ACER vs. ECRB)	

Table 93: The main suggestions presented in the discussion papers

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LIST OF USED ABBREVIATIONS AND TERMS

ACER - Agency for the Cooperation of Energy Regulators

ACQ - annual contracted quantity

BAL NC – Commission Regulation establishing a Network Code on Gas Balancing of Transmission Networks (312/2014/EU)

BBL - Balgzand Bacton Line, interconnection point between the Netherlands and the UK

BeLux – the Belgian-Luxembourgish merged gas market

CAM – see CAM NC

CAM NC – Commission Regulation establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems (984/2013/EU)

CB - cross-border

CEER - Council of European Energy Regulators

CEGH - Central European Gas Hub AG, Austrian virtual trading point

CESEC - Connected regional initiative for the Central and South East European region

CMP - congestion management procedures; Annex I to Regulation (EC) 715/2009 on conditions for access to the natural gas transmission networks, as amended

CMP GL - Congestion Management Procedures Guidelines (see CMP)

CSEE - Central and South-East Europe

CWD - capacity weighted distance methodology

DSO - distribution system operator

EC - European Commission

ENTSOG - European Network of Transmission System Operators for Gas

Eustream - eustream a.s., Slovak natural gas TSO

FID - Final Investment Decision status according to the TYNDP

Gaspool - GASPOOL Balancing Services GmbH, German virtual trading point

GCA - GAS CONNECT AUSTRIA GmbH, Austrian natural gas TSO

GIIGNL - International Group of Liquefied Natural Gas Importers

GOG - Gas-on-Gas pricing

GRTgaz - GRTgaz Deutschland GmbH, German natural gas TSO

HHI - Herfindahl-Hirschman Index

HsK - Hora Sv. Kateřiny

IGM - internal gas market

IP - interconnection point

IUK - Interconnector UK, interconnection point between the UK and Belgium

LNG - liquefied natural gas

LT - long-term

LTC - long-term capacity contract

MS – EU Member State

MWh – megawatt-hour; when the original figure was stated in cubic metres, the conversion of 1 m^3 = 10.6 kWh was used

NBP - National Balancing Point, British virtual trading point

NC – network code

NCG - NetConnect Germany, German virtual trading point

NRA - National regulatory authority

NS2 - Nord Stream 2

NWE - North-West Europe

OGE - Open Grid Europe GmbH, German natural gas TSO

OPEX – operational expenses

PCI - project of common interest

PEG Nord - Point d'échange de gaz – Nord, French virtual trading point

PSV - Punto di Scambio Virtuale, Italian virtual trading point

RAB - Regulatory Asset Base, specific costs or revenues that a public utility can defer to its balance sheet

Reference Scenario – a basis scenario for the modelling, assuming current regulatory scheme fully implemented and taking into account planned infrastructure investments

REMIT - Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency

ROC - Regional Operating Centre

SNAM - Snam S.p.A., Italian TSO

SoS - security of supply

Status Quo - 2016 IGM market conditions

SWE – South-West Europe

TAP - Trans-Adriatic Pipeline

TAR NC - Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas

TCF - TSO compensation fund

TEP, Third Energy Package - European Union's legislative package for an internal gas and electricity market in the EU

ToP - take or pay, contractual obligation to take a certain level of the commodity

TPA - third-party access

TSO - transmission system operator

TTF - Title Transfer Facility, a virtual trading point for natural gas in the Netherlands

TYNDP – Ten Year Network Development Plan issued by ENTSOG

UGS - underground gas storage

UIOLI – Use-it-or-lose-it principle

WACC - weighted average cost of capital

ZEE - Zeebrugge Hub, Belgian virtual trading point

LIST OF FIGURES

LIST OF TABLES

MJ-04-17-426-EN-N

MJ-04-17-426-EN-N

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