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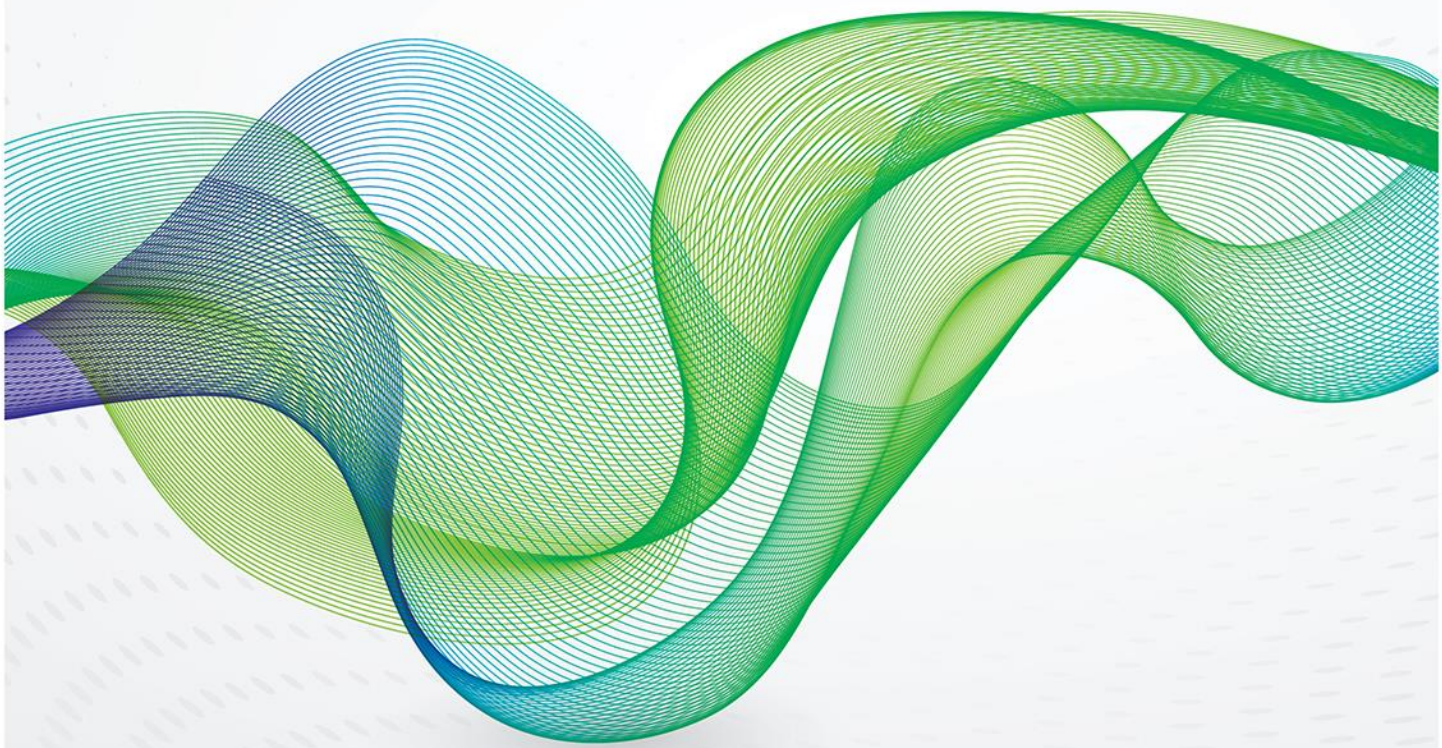
European gas grid through the eye of the TIGER:

investigating bottlenecks in pipeline flows by modelling history



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Authors' Foreword

This joint study was conducted by Harald Hecking and Florian Weiser, researchers at ewi Energy Research & Scenarios and Beatrice Petrovich and Howard Rogers, research fellows at the Oxford Institute for Energy Studies.

Preface

Academic collaboration is arguably most successful when different skills are brought together to address a research question which overlaps core areas of competency in an even manner. If the chemistry of the combined team works well, the results are truly synergistic. In such a spirit, this paper brings together findings from previous leading edge OIES research on European gas hub price correlation by Beatrice Petrovich with demonstrated excellence in European gas transmission system modelling by Harald Hecking and Florian Weiser at ewi Energy Research and Scenarios at the EWI Institute in Cologne.

The paper compares the evidence for periodic bottlenecks in Europe's gas transmission systems, indicated by price correlation de-linkage - and supporting evidence of apparent physical or contractual flow constraints - with the results obtained by 're-running history' using the EWI TIGER model. The modelled view of history presumes 'perfect market' behaviour in respect of agents making the best use of infrastructure ('lowest cost' objective function) to move gas from A to B given data on tariff costs.

A 'tidy' confirmation that modelled and actual flows were broadly in line would have been welcomed by those regulatory bodies tasked with achieving the Gas Target Model. The findings of this paper suggest that much more work is necessary to ensure that: critical route capacities are increased, capacities each side of specific interconnector points are better harmonised and that capacity held under long term contracts is made available on a shorter time horizon. The forensic investigation contained in this paper is to be highly commended and is an excellent starting point for regulatory bodies.

This is far from merely an interesting academic study. Europe's gas flow patterns will markedly change over the next ten years as domestic production declines, leaving a growing import requirement to be met by the imminent surge of global LNG supply and/or Russian pipeline gas. The 'problem areas' of linkage between North and Southern France and the corridors between Germany and Italy via Austria and Switzerland, complicated by new flows to Ukraine, will need to achieve a robust level of responsiveness in this timescale. This paper provides both a timely reminder of the work required and an excellent indication of where such work should be focussed.

Howard Rogers

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September 2016

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1. Background, the research question and its relevance

Work by OIES in September 2015[1] monitored the alignment between European hub prices in 2014 with the aim of identifying the remaining barriers to the free trade of gas between the main European gas hubs[2], and their underlying drivers. Although prices were overall well aligned in 2014, the persistence of some price disconnection suggests that all price arbitrage opportunities could not be exploited through short term trading as some physical or contractual constraints remained, these being an obstacle to a truly integrated European gas market.

In particular, in 2014, we observed 3 cases of barriers to free trade, or "bottlenecks":

1) PEG Sud (**PEGS) hub delinking from PEG Nord (PEGN) hub**, driven by physical congestion at the North/South link in France. This was fostered by a lack of –affordable - LNG imports in the South of France and high exports from PEG TIGF to Spain, in turn leading to a high requirement for gas to be shipped southwards from the more liquid hub in the north that could not be supported by the existing transmission capacity connecting PEGN to PEGS.

2) the Austrian hub (**CEGH) delinking from the German NCG hub**, driven by increasing the requirement to ship gas eastwards, due in part to reverse flow to Ukraine, and Russia not meeting nominations in the summer of 2014, that led to a frequent saturation of transmission capacity to exit Germany at the Oberkappel IP on the Austrian border. Such a physical bottleneck was especially accentuated by physical constraints on the German side (disparity between entry and exit capacity, plus pressure constraints in the MEGAL system).

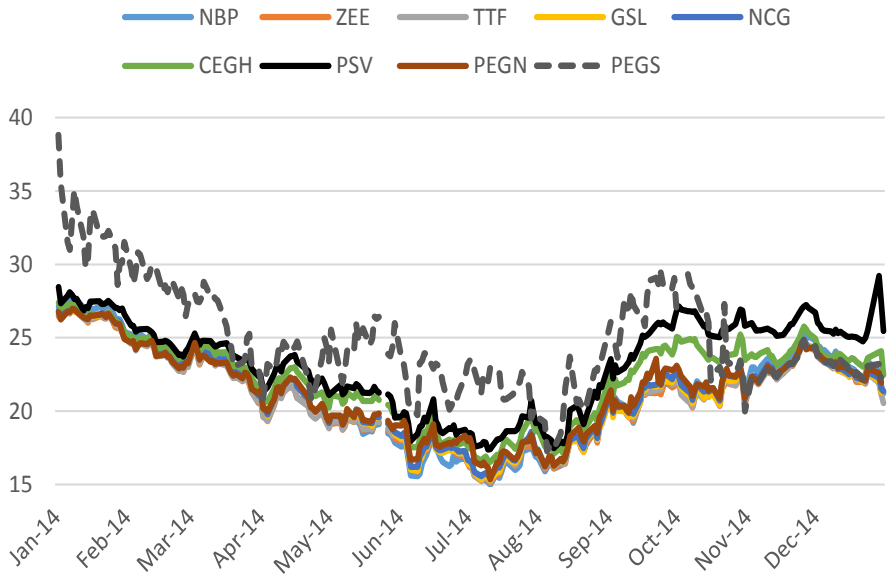
3) the Italian **PSV hub delinking from NCG and other North West European hubs**, supported by under-utilisation of the existing transmission capacity linking PSV to the more liquid markets in the North. Such underutilization of cross border transmission capacity on the NCG-Switzerland-PSV pipeline route reflects other than physical barriers to trade and has been partially alleviated by re-sales of pre-booked capacity on an interruptible basis carried out by TSOs and by ENI's release of long term booked capacity through periodical auctions.

Figure 1 shows the price delinkages in the course of the calendar year 2014: PSV, PEGS and CEGH prices, in fact, are not perfectly aligned to the other European gas markets.

[1] Petrovich (2015).

[2] A gas hub is the location, physical or virtual, where a traded market for gas is established. In what follows gas hubs and gas markets are synonymous.

Figure 1: OTC day-ahead Gas Prices (€/MWh) in different Market Areas



Source: Tankard Parties

New data on OTC and exchange trades confirmed the persistence of such delinkages in 2015 as well[3]. The same data evidence showed that other newly developed hubs that are well connected to those of North West Europe, such the Czech hub, although displaying a low liquidity, feature prices which are perfectly aligned to the North West hubs' "core group".

Based on this background, our first research question is: could we reproduce historic bottlenecks if we imposed a least cost (i.e. transport cost-minimising) allocation of flows in which all price arbitrage opportunities are exploited? In other words: was the existing transmission capacity optimally used and sufficient to allow the free trade of gas across borders and hence achieve a truly integrated European gas market, as envisaged by the European Gas Target Model[4]?

The natural follow-up of this question is: assuming that we found that historical flows were not similar to this least cost solution, can we identify which contractual constraints and/or cases of market power explain historical flow patterns?

The paper is structured as follows: Chapter 2 presents the Methodology we adopted to answer research questions outlined in Chapter 1, Chapter 3 provides an overview of data used in the analysis; Chapter 4 presents the findings derived from the comparison between the optimal flow solution and historic flow pattern in 2014 for selected interconnection points, by exploring the possible drivers of the disparities or similarities between the historically observed and modelled flows. Chapter 5 concludes.

[3] Petrovich (2016).
[4] CEER (2011).

2. Methodology

In order to answer our research questions we compare historical flow patterns within the European grid[5] against the results of a least cost gas flow model dispatching in a fully competitive setting with fixed gas intakes into Europe (hereafter: "perfect competition solution or simulation"), obtained by:

- considering the existing structure of the network (see Appendix I for a detailed representation) and related transmission tariffs,
- fixing the key supply volumes to Europe (i.e. pipeline imports, LNG imports, domestic gas production) and consumed volumes in each regional market at the levels historically observed in 2014,
- assuming that at all gas suppliers to Europe are price-takers (perfect competition hypothesis),
- choosing the combination of gas flows within the European grid that minimizes transport costs and at the same time meets all demand requirements across Europe.

In order to derive the perfect competition solution we used the European supply-demand transmission model TIGER. The TIGER model was developed by EWI at the University of Cologne; it works using as inputs demand, production capacities of major gas suppliers, European domestic production, information on long term contracts, transmission tariffs data and gives as an output a pattern of physical gas flows within Europe. TIGER is a cost minimizing model: the whole system is optimized with regard to the cost for the gas supply, subject to several infrastructure constraints, e. g. capacity limits of pipelines or injection/withdrawal storage curves. Consequently, TIGER simulated flows are the optimal ones, meaning that such flows are "as if" every arbitrage opportunity were exploited to the extent that available infrastructure allows. For a technical model description, please refer to Lochner (2011).

The nature of our research question requires that we use TIGER to "re-run" history, i.e. we use TIGER in the following way: given the actual daily data on demand, domestic production, storage inventory levels at certain dates, the most important import-export flows to/from pipeline and LNG imports to Europe and data on transmission tariffs; we ask the TIGER model to simulate the least cost pattern of flows within the European grid geography (that is basically the flow pattern within Europe that minimizes the transport costs, subject to capacity constraints).

More specifically, we fix the following quantities in the model based on historic data for 2014 described in Chapter 3:

- Send-outs from LNG terminals: we fix send-outs from LNG terminals on a daily basis for Italy, France and Spain (by terminal). Other LNG send-outs are fixed on a yearly basis (by country) on the basis of historic import data.
- Pipeline imports to the EU: the flows from Norway to PEG Nord, and from Ukraine to Slovakia are fixed on a daily level. Other imports are fixed either on a yearly level (Algeria to Spain, Algeria to Italy, Russia to Germany via Nord Stream, Poland to Germany), or indirectly by fixing take-or-pay levels[6]. We take into account that Russia stopped sales to Ukraine on July 14th 2014.
- Demand: we fix demand on a daily basis for key countries (Italy, France, Netherlands, Germany, Austria, Czech Republic, United Kingdom) or on a yearly level (all other European countries).

[5] The coverage of the model includes all countries that are geographically in Europe and are connected by gas pipelines, including Turkey, Ukraine and Belarus. The modelled pipelines are the transmission system for gas. The distribution system is not included.

[6] Take or pay levels are estimated based on EWI research.

- Production: European domestic production is fixed at historical levels on a yearly basis (by country).
- Storage: storage optimization is endogenous but storage stocks at given points in time are fixed at historical levels at country level (January 1st, November 1st, December 31st 2014)

It is worth noticing that in this exercise, import contract pricing details are not relevant.[7] In particular, we simply assume that the price of gas injected into the European grid, although coming from different sources, is the same and therefore what matters is matching daily demand with a mix of sources that minimises the cost of shipping gas from the point where the gas is 'injected' into the system, up to the virtual trading points where consumption will take place. Unless transmission tariffs are very different across IPs (a point which will be discussed in Chapter 3), minimizing the cost of shipping gas to centres of consumption means minimising the shipping distance: the fewer entry/exit points[8] the gas volume has to pass through, the fewer entry/exit tariffs are charged on the volume. In this environment, markets that are more distant from the gas source pay a higher price for delivering their gas, due to an effect which is also known as tariff "pancaking"[9].

We focus on the calendar year 2014 which is the most recent year to date we have final flow data available for.

The predictions for the comparison between real flow decisions and the result of the perfect competition solution10 are:

1) If an historical bottleneck also emerges in the perfect competition simulation, this confirms the physical nature of the bottleneck and suggests that, assuming that the policy target is closer price alignment, there is a need for more transmission capacity at that interconnection, as cross border capacity is not sufficient to connect adjacent markets.

2) Divergences between reality and the perfect competition simulation in terms of the emergence of bottlenecks signal that suboptimal utilization of existing capacity is occurring (i.e. non-physical barriers to trade)

The match between historical and simulated daily flows, is therefore especially interesting at the three links described in Chapter 1 (i.e. PEGS/PEGN, CEGH/NCG, PSV/NCG), namely those where bottlenecks have historically been observed. Our purpose is to see whether the perfect competition simulation reproduces the physical bottlenecks identified in the price delinkage analysis, or not. If the result is 'yes' (prediction 1), this would suggest the need of additional investment to upgrade existing cross border capacity at such interconnection points, provided that supply/demand patterns do not radically change and the policy target is closer price alignment.

For points where the price delinkage analysis concluded that contractual congestion was possibly occurring (PSV/NCG), the comparison may confirm this (prediction 2) and shed some light also on whether the existing physical capacity would have been sufficient to avert the bottleneck if it was fully exploited. If not, this would suggest that, on top of solving the existing non-physical barriers to trade, additional investment to upgrade existing cross border capacity at such interconnection points would be required (provided, of course, that supply/demand patterns do not radically change and that the policy target is closer price alignment).

[7] We assume some contractual obligations in the model. Take-or-pay volumes define minimum cross-border flows between countries. So, fixing take-or-pay volumes is an alternative to fixing the historic volumes that leaves the model with some degree of freedom at a specific cross-border point.
[8] European gas transport tariffs are determined using the entry/exit approach. For details on this system: Hunt (2008).
[9] See amongst others LECG (2011), P.1 and ERGEG (2006), P.10.
[10] At a later stage, these simulated flows will also serve as a benchmark for future scenario model runs (where we change assumptions on demand and supply patterns to see the effect on flow geography).

After this assessment, we explored the reasons behind any deviations between the simulation and reality. In order to do so we added some constraints on the TIGER historic simulation in order to move from a “fully competitive” world to one where some contractual congestions exist, e. g. we simulated a reduction in available transmission capacity. By including such constraints, we expected to obtain resulting simulated gas flow patterns which were more similar to what we observed in reality.

3. Data

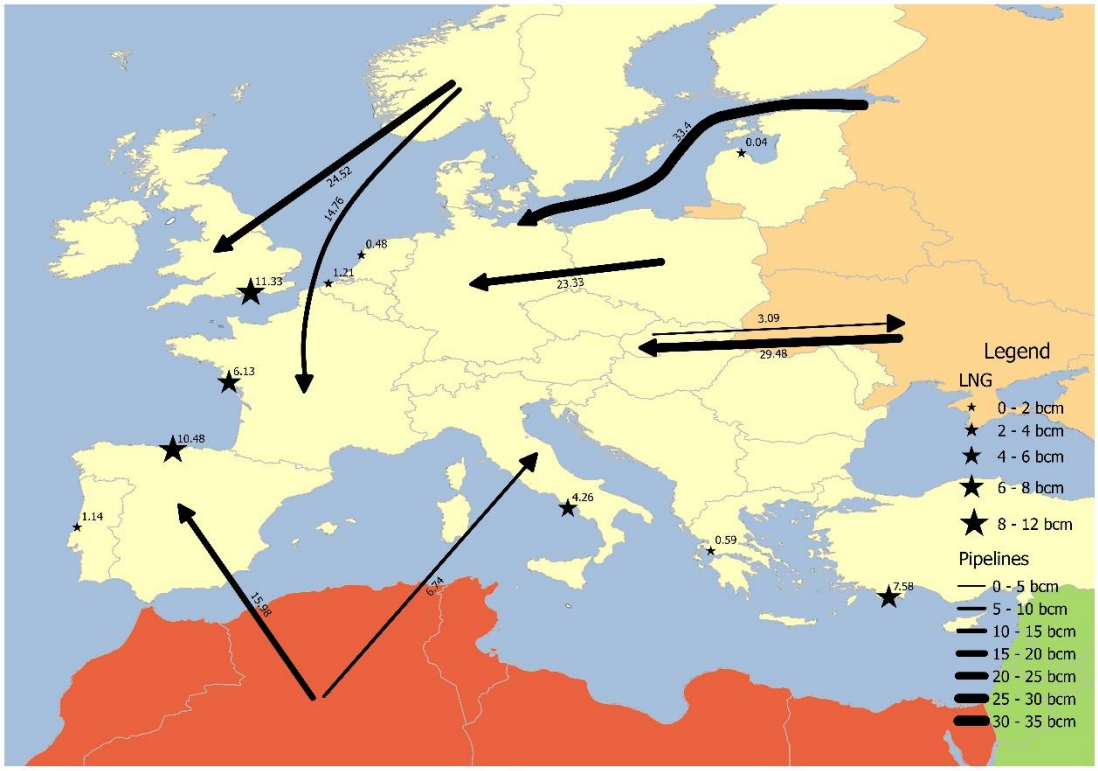
Historical daily gas flows between European hubs

Using the ENTSOG Transparency platform[11] and information publicity available on TSOs’ websites, data on daily historical gas flows and daily technically available transmission capacity for 2014 were collected. Real daily interconnection capacity ‘utilization rates’ (or ‘load factor’) were computed for the Interconnection Points (IP) where de-linkages occurred in 2014.

Import flows to Europe

Using the ENTSOG Transparency platform[12] and information publicity available on TSOs’ websites, data on daily historical pipeline imports from Norway to PEG Nord and Ukraine to Slovakia in 2014 were collected. All other import flows shown below in Figure 2 were fixed on a yearly basis with data from the IEA Natural Gas Information.[13] Additionally, take-or-pay-levels that can be seen in Figure 3 defined a minimum flow on certain routes.

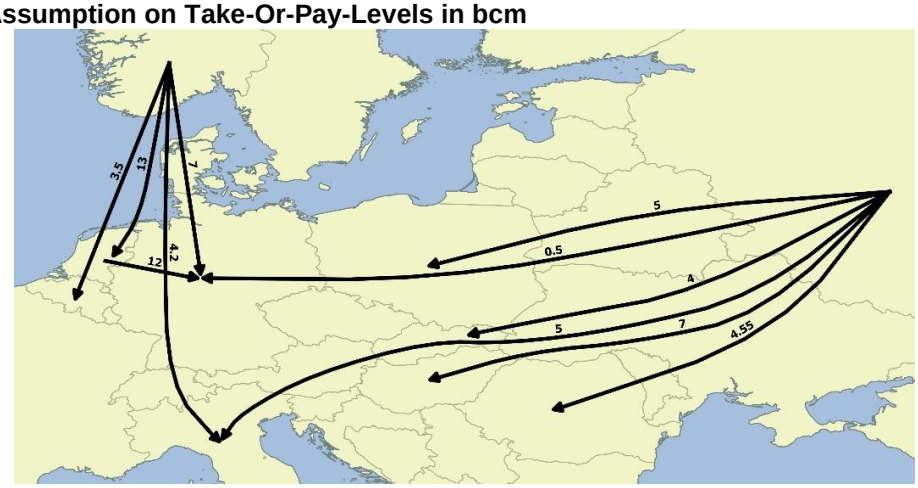
Figure 2: Import flows that are exogenously fixed in the model, either on a daily or yearly basis



Source: ENTSOG Transparency Platform, IEA, GLE

[11] ENTSOG (2016)
[12] ENTSOG (2016)
[13] IEA (2015)

Figure 3: Assumption on Take-Or-Pay-Levels in bcm

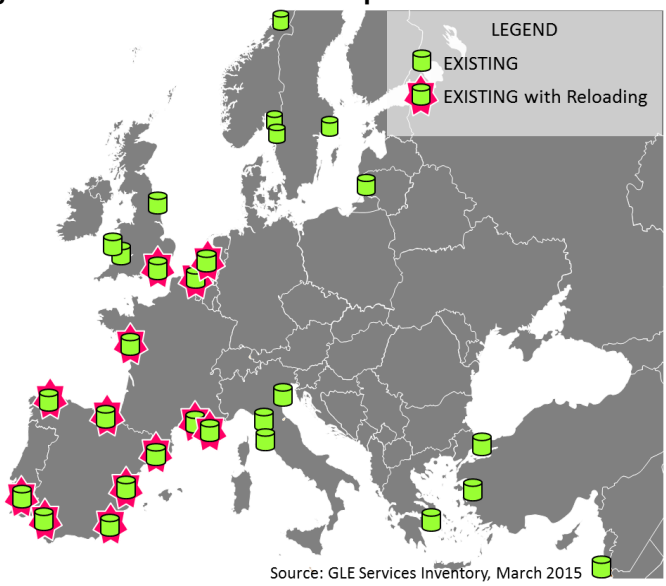


Source: EWI

Send-outs from LNG terminals

Daily send-out data by regasification terminal in Spain, France and Italy is based on information disclosed by GIE/GLE, IEA and TSOs[14]. The yearly send-outs for the other European LNG importing countries (Figure 4) are based on IEA Natural Gas Information 2015.[15] It is worth noticing here that we fixed send-outs from regasification terminals, not LNG volumes imported into facilities located in the South of France. Once a cargo lands in a facility, regasification capacity users may in fact have some degrees of freedom in setting the daily send-outs, subject to the regasification terminal's technical constraints, and in particular subject to the terminal's inventory capacity and nomination flexibility. In the simulation, the TIGER model does not optimize the level of send-outs over the year, as this is exogenous.

Figure 4: Existing regasification terminals in Europe



Source: GLE

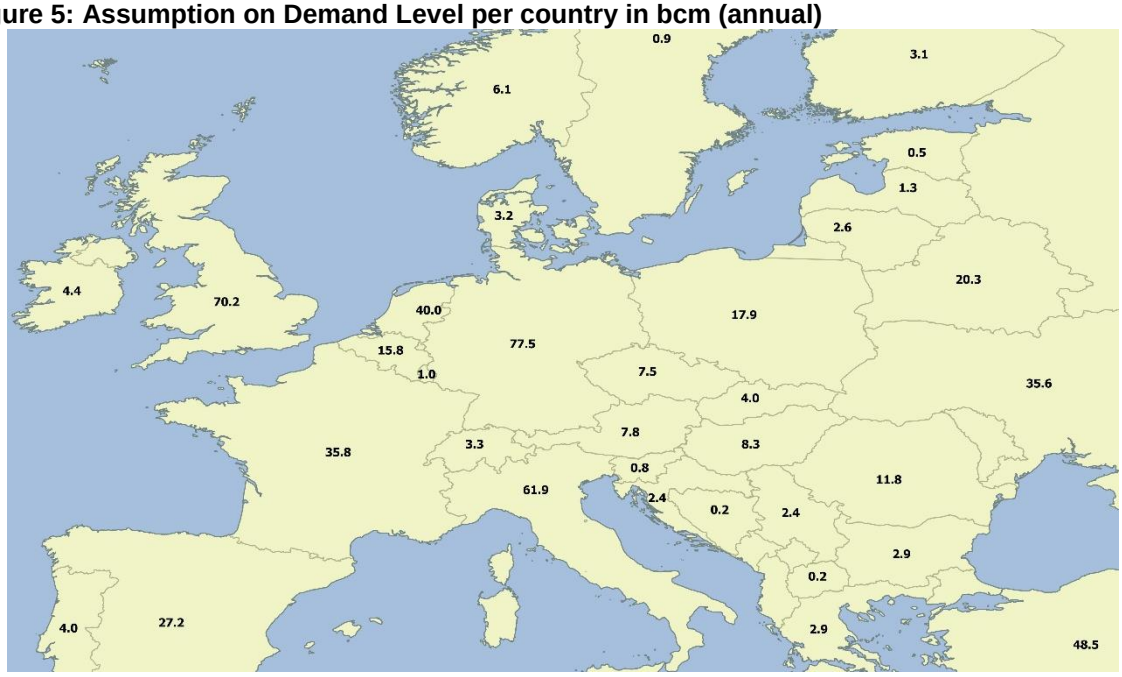
[14] In more detail, we relied on data published by Snam Rete Gas for Italian terminals and by GRTgaz for French ones.
[15] IEA (2015).

Storage injection/withdrawals
Storage levels at given points in time (January 1st, November 1st, December 31st 2014) were fixed based on Gas Storage Europe daily data gas stocks at hub/site level.

Yearly domestic production
We use yearly production volumes based on IEA's Natural Gas Information 2015.[16] The exact production profile is endogenous to the model.

Demand Data
A daily demand profile was obtained using TSO data for Italy, France, Netherlands, Germany, Austria, Czech Republic and United Kingdom. Based on daily storage injections / withdrawals and cross border flows that are publicly available on TSOs' websites, it is possible to calculate the demand as a residuum if one assumes a seasonal production profile. For the remaining countries, we use yearly demand figures based on IEA's Natural Gas Information 2015. Figure 5 shows an overview of the demand assumptions.

Figure 5: Assumption on Demand Level per country in bcm (annual)



Source: IEA, EWI

Transport tariffs
Having correct inputs for the cost of transmission capacity (transportation tariffs) is crucial in this exercise. In fact, in the modelling the flows are basically determined, along with the existing technical transmission capacity, by the relative transmission costs at different border points. Further, in the absence of constraints, the difference between zonal prices equals the transmission fee.

We assume "steady" flows and start from the cost of yearly transmission capacity to compute a variable transmission cost for each possible connection between hubs. For instance, if we have 365€ / MWh / day / year cost to go from hub A to hub B, we would have a cost of 1/365 * 365= 1 € / MWh. In other words, we assume a 100% variable average transmission fee for each group of IPs connecting one price area to another (notwithstanding that IPs connecting the same hubs may have different fees and notwithstanding the fact that the same IP may be operated by different TSOs and these TSOs may charge different fees).

[16] IEA (2015)

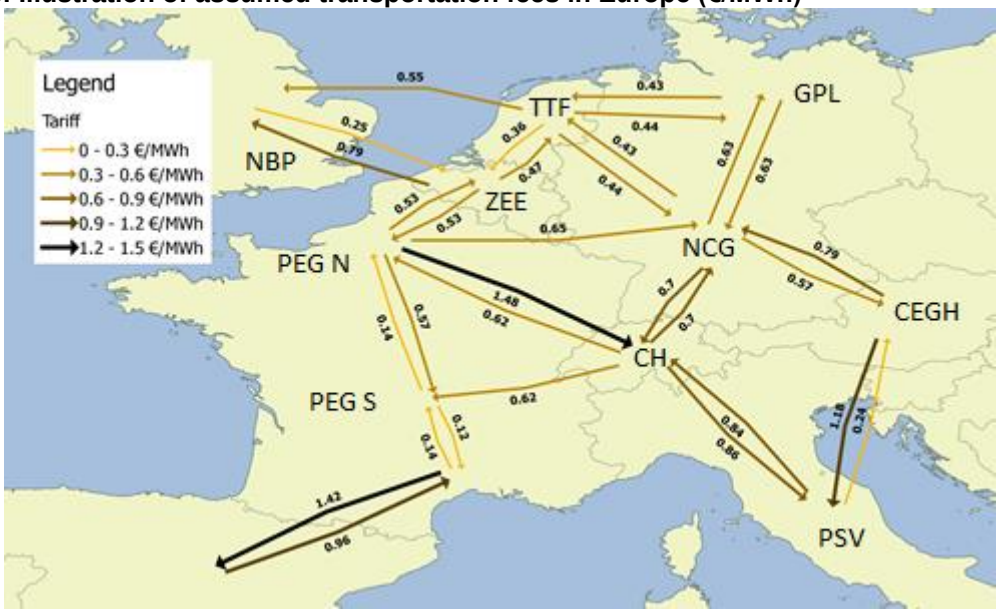
Data on the cost of yearly transmission capacity are mainly based on the ACER Market Monitoring Report 2013 (MMR).[17] For those not included we researched using information disclosed by TSOs and Energy Regulators. ACER 2013 MMR presents a simulation of cross-border charges for flowing 1 GWh/day/year by entry/exit IP, based on published tariffs and a "certain consumption profile". Figures provided by ACER are average charges, weighted by IP capacity level for those borders featuring more than one IP or operated by more than one TSO applying different charges.

Most of the tariffs range between 0.2 €/MWh and 1.5 €/MWh. The resulting transportation fees are illustrated in **Figure 6**.

Note that values for tariffs involving Swiss TSOs were recently added into the TIGER set up in order to analyze the NCG – PSV congestion. ACER MMR reports a tariff of 0.803 €/MWh to go from Wallbach, on the Germany/Switzerland border, or from Oltingue, on the France/Switzerland border, to the Italian border. This is a price of the "transit" rather than an entry exit tariff.[18] The capacity allocation mechanism in Switzerland is not a fully transparent one, and EU network codes are not binding there, so there is no formal obligation to improve transparency[19]. Swissgas and Fluxswiss are not partners in ENTSO-G Transparency Platform.[20]

It is assumed that entry costs are zero for domestic production. Entry costs for gas coming from extra-European countries and entering the European grid are assumed on the basis of EWI research. In particular, it is assumed that it is cheaper to ship gas to Gaspool by the Yamal route than by Nord Stream, and that the latter has a lower cost than that attached to the Ukraine corridor.

Figure 6: Illustration of assumed transportation fees in Europe (€/MWh)



Source: ACER, EWI

[17] ACER (2014).
[18] Since the model requires an entry / exit tariff for Switzerland, we assume that the cost for the total transits is distributed 50% to an entry fee, and 50% to an exit fee.
[19] Despite negotiations, no agreement has been reached on EU-Swiss energy cooperation yet (as of June 2016). The conclusion of a deal concerning further integration of Swiss and EU energy markets (including electricity market coupling) has been on hold since Switzerland voted a restriction on free movement of EU citizens into its territory (a referendum took place in February 2014) and it is likely to remain suspended until the conflict over the free movement of people is resolved.
[20] ENTSOG (2016).

Regasification costs
We do not take account of terminal specific regasification costs. This is in line with the assumption that all gas supplies enter the European pipeline grid at the same cost. It also resembles a situation where the cost of regasification capacity is regarded as a sunk cost for the user.

4. Re-running history in a fully competitive world

In this Chapter we analyse disparities and similarities between the historically observed and simulated flows, focusing on the three IPs where bottlenecks were identified in 2014 using the price delinkage approach[21]:

1) Wallbach IP, connecting NCG to Switzerland, on the route from the German NCG to the Italian PSV (Chapter 4.1); according to the price delinkage analysis the nature of the congestion at this border point is non-physical.

2) Oberkappel IP, at the German-Austrian border, in the direction towards Austria (Chapter 4.2), according to the price delinkage analysis the nature of the congestion at this border point is physical.

3) North-South Link connecting the Northern French gas market, the PEGN, to the Southern one, the PEGS (Chapter 4.3); according to the price delinkage analysis the nature of the congestion at this border point is physical.

4.1 NCG to PSV

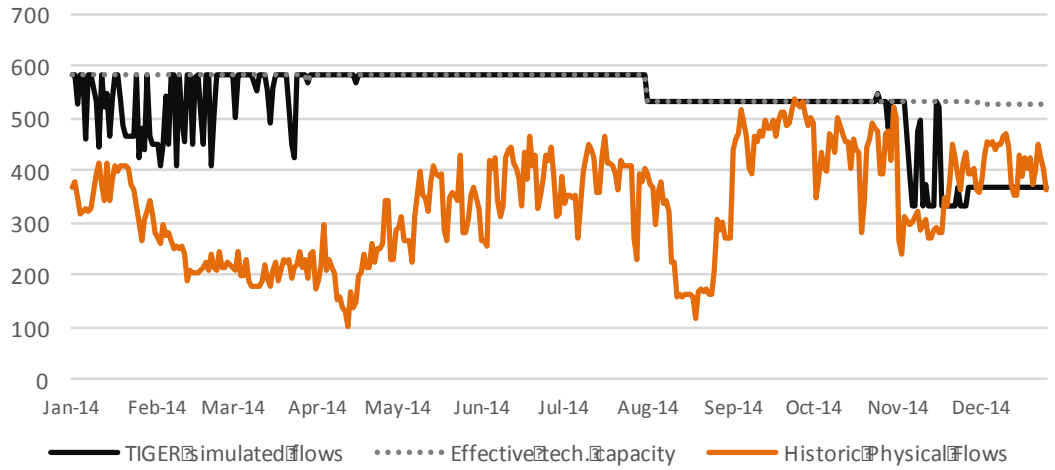
As expected, the least cost simulation exploits capacity on the NCG-Switzerland-PSV pipeline system[22] more heavily than what we actually observed in 2014 (**Figure 7**). The result confirms the expectation that non-physical barriers to trade could be the driving force behind the persistent premium paid for gas in Italy compared to neighbouring markets in North West Europe[23]; this price premium (about 1.6 €/MWh) appears to be higher than the estimated cost of transporting the commodity from the German NCG to the Italian market zone[24].

Interestingly, in a report published in May 2016, the Agency for the Cooperation of Energy Regulators (ACER) found that the German exit side of the Wallbach IP towards Switzerland was contractually congested in 2015[25], which is consistent with our findings.

In more detail, in order to minimize the cost of gas supply to Italy, the TIGER model fully utilizes the interconnection capacity between the German NCG market and Switzerland, in the direction towards Italy, from April to November, as opposed to what actually happened in 2014, when the utilization rate exceeded 80% only in September and October. Physical flows at Wallbach IP were close to maximum technical capacity only on 7% of the days in 2014 and, for the rest of the year, a significant part of the interconnecting capacity was unused (**Figure 8**).

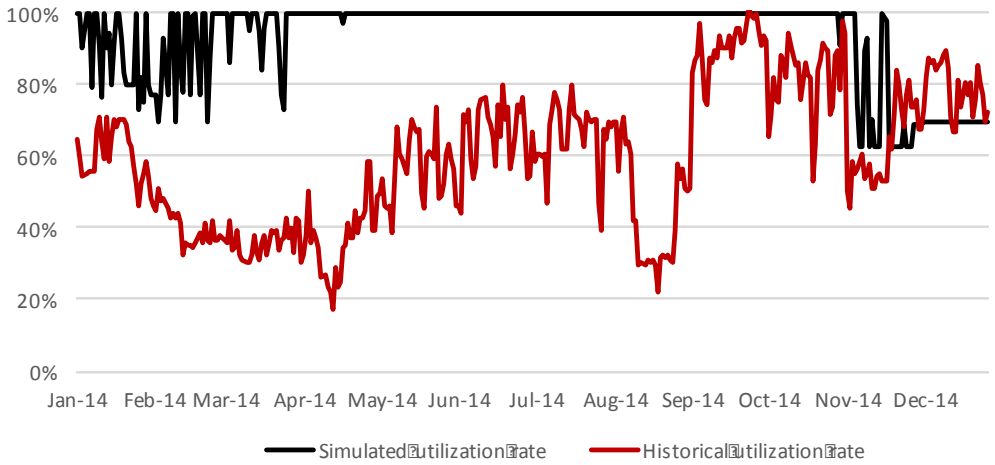
[21] Petrovich (2015).
[22] Gas can flow from NCG in Germany heading to the Italian PSV, passing through Switzerland, which represents a mere transit country. The pipeline Transitgas, in fact, crosses Switzerland from Wallbach, at the end of the TENP pipeline located on the border with Germany, to Gries pass/Passo Gries, located at the Swiss-Italian border. Note that the capacity to exit Germany at Wallbach IP is lower than the capacity to enter Italy at Passo Gries, therefore we focus on the utilization of the former interconnection point. For an illustrative representation for the NCG-to-PSV pipeline system refer to Appendix II.
[23] The PSV-NCG day ahead price difference observed in 2014 exceeded 1.5 €/MWh for the majority of days, and stayed constantly above 2 €/MWh starting from September. For a more detailed discussion: Petrovich (2015), Chapter 7.3.
[24] Note that this estimate, if we assume a transport cost from TTF to NCG of about 0.4 €/MWh, is slightly lower than the Italian Energy Regulator's estimate for the average cost of transporting 1 MWh of gas from TTF into the Italian gas network in 2014, equal to 2.6 €/MWh (Source: sum over the QTint, QTpsv and QTmcv components of the regulated gas price for protected domestic gas consumers as published in AEEGSI resolutions 139/2013/R/gas, 134/2014, 85/2014).
[25] ACER (2016), P.17.

Figure 7: Simulated and historical utilization flows from NCG to Switzerland in 2014 (GWh)



Source: EWI TIGER Simulation, ENTSO-G Transparency Platform, SRG

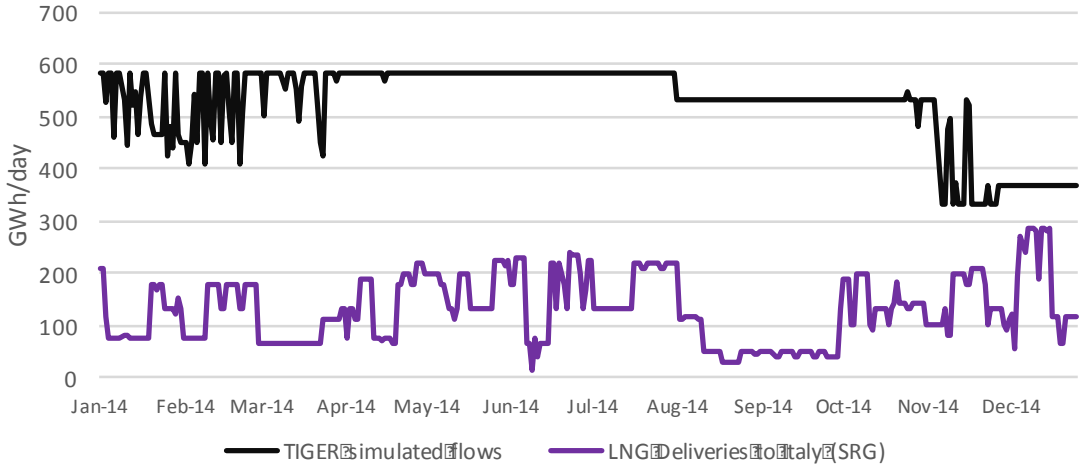
Figure 8: Simulated and historical utilization rate from NCG to Switzerland in 2014 (%)



Source: EWI TIGER Simulation, ENTSO-G Transparency Platform, SRG

In the simulation, the saturation of the NCG-to-PSV pipeline system declines, starting from November, at the same time as more LNG was delivered at Italian regasification terminals, reducing the need to ship gas from the Northern borders (**Figure 9**).

Figure 9: Simulated gas flows from NCG to Switzerland in 2014 and Italian regasification terminals send-out (GWh/day)



Source: EWI TIGER Simulation, GLE, SRG

More interestingly, the model also predicts that, even if the full capacity on Transitgas was used, there would be a physical congestion between PSV and NCG, at least in some periods. This would suggest that, on top of solving the existing non-physical barriers to trade, additional investment to upgrade existing cross border capacity at Wallbach IP would be required (provided, of course, that supply/demand patterns do not radically change and that the policy target is closer price alignment).

Although robust evidence for the alternative logics behind the observed pattern is not available due to the confidentiality of contractual agreements, we assume that long term shipping contracts play a role in the limited utilization of the NCG to PSV pipeline system even though the Italian market paid a substantial premium for the commodity.

We estimate that above 80% of transmission capacity on the route from NCG/TTF to PSV is booked long term by ENI[26] and it may be difficult to make it available to other participants when ENI does not use/nominate it, especially on the Swiss side, where transmission capacity allocation is performed through private auctions[27] and EU rules on contractual congestion are not mandatory (unless an agreement is found with the Swiss authorities[28]).

Moreover, on the Italian side of Passo Gries/Gries Pass IP not all congestion management procedures envisaged by European Regulation[29] are being applied. In fact, only voluntary capacity surrender applies. In particular, the Italian Energy Regulator mandated[30] the introduction of the so

[26] Source: Case COMP/B-1/39.315- ENI - Commitments submitted to the European Commission, dated February 4, 2010, p.32-33. Available at: http://ec.europa.eu/competition/antitrust/cases/dec_docs/39315/39315_2670_8.pdf. The Italian Antitrust Authority in September 2012 wrote that the share of transmission capacity on the Transitgas pipeline allocated to ENI on the basis of long term ship-or-pay agreements equals about 85-95% of total capacity (Source: http://www.agcm.it/trasp-statistiche/doc_download/3287-a440chiusura.html, P.11)

[27] In 2011 FluxSwiss acquired Eni's stake in the ownership of Transitgas AG (46%) and since then acts as independent transmission system operator with the right to commercialize 90% of capacity in the Transitgas pipeline. In 2011 Fluxys TENP acquired Eni's stake in the ownership of TENP KG (49%) and Fluxys TENP TSO acts as independent transmission system operator with the right to commercialize approximately 64% of capacity in the TENP pipeline. Source: FluxSwiss press release available at: http://www.fluxys.com/tenp/en/NewsAndPress/2011/111130_TENPTransitgas

[28] No agreement has been reached on EU-Swiss energy cooperation yet (as of June 2016).

[29] Annex I to EC Regulation No 715/2009 of the European Parliament and of the Council (as amended by the Decision of the Commission of 24 August 2012)

[30] Resolution 137/02, art. 14 ter., available at : http://www.autorita.energia.it/allegati/docs/02/137-02.pdf

called “long term use-it-or-loose-it (LT UIOLI)” congestion management procedure[31] in 2013, which should have been implemented at all the Northern entry points to the Italian gas grid (namely Passo Gries/Gries Pass at the Swiss border, Tarvisio at the Austrian border and Gorizia at the border with Slovenia). However, this procedure has not been implemented yet (as of June 2016). In June 2014 the Italian gas TSO Snam Rete Gas published and launched an open consultation on a first proposal to review its Network Code in order to introduce LT UIOLI[32] that still remained on paper. A new proposal on the same procedure was then presented by the Italian gas TSO to the Regulator in December 2014, who in turn opened another consultation on it, expiring at the end of March 2016[33].

Notwithstanding the absence of a mandatory release of unused capacity on the Swiss-Italian border, in response to an antitrust competition inquiry, ENI committed to release part of its transmission capacity booked on a long term basis on the TENP-Transitgas route, through subsequent system-marginal-price auctions[34] to be held from September 2012 to October 2017. However, it is possible that some of these auctions did not clear as no player was interested in getting that capacity at the minimum prices requested by ENI. The results of such auctions are not publicly available, but they concern gas year and six-month capacity products and their reserve price is equal to transmission tariffs paid by ENI to TSOs involved in the TENP-Transitgas, plus a "reasonable margin"[35].

Even if the capacity release programme was not successful, some long term booked capacity, when not used by ENI, may have been made available to the market either on the secondary market, or by means of sales of interruptible capacity by the TSOs involved. However, insufficiently flexible capacity allocation procedures may have been a further obstacle to ship gas from Germany to Italy, via Switzerland, so explaining why existing flows do not conform to 'pure economic logic' on the Germany to Italy route.

The partial exploitation of the Transitgas pipeline system, allowed by long term capacity booking and lack of coordination in the allocation procedures, has repercussions on other portions of the European grid, a fact that is assessed in the next Chapter.

4.2 NCG to CEGH

The comparison between history and simulation for Oberkappel IP[36] suggests that existing flows do not conform to 'pure economic logic' on the Germany to Austria route. In fact, while in 2014 Germany-to-Austria cross border capacity at this border point was constantly near to saturation starting from April, the model does not reproduce this physical bottleneck (**Figure 10**). In fact, the cost minimising model never ships gas from Germany to Austria, unless it is necessary to compensate for the cessation of Russian supply to Ukraine, as happened in October and November (**Figure 11**).

[31] EC Regulation No 715/2009, paragraph 2.2.5. of Annex 1 mandates that regulatory authorities require TSOs to partly or fully withdraw contracted capacity that is systematically underutilized on an interconnection point by a network user where the latter has not offered his unutilized capacity under reasonable conditions and where other network users request firm capacity.

[32] Proposal to amend Snam Rete Gas Network Code n.29, available at: http://www.snamretegas.it/it/servizi/Codice_di_rete/Aree/aggiornamento.html

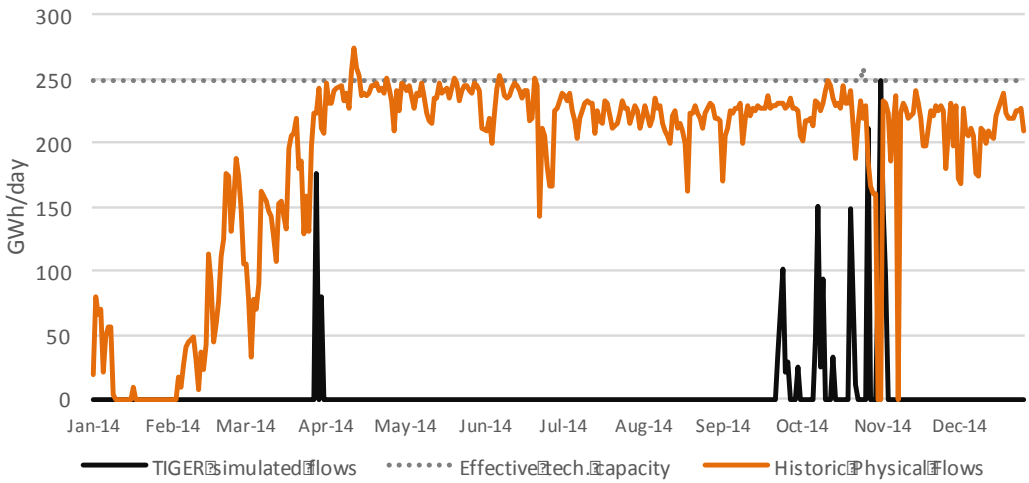
[33] AEEGSI consultation document 60/2016/R/gas, available at: http://www.autorita.energia.it/it/docs/dc/16/060-16.jsp (unofficial English translation available at: http://www.autorita.energia.it/allegati/inglese/060-16eng.pdf)

[34] The commitment was undertaken in 2012 by ENI in response to an antitrust competition inquiry carried out by the Italian Antitrust Authority for alleged abuse of dominant position. Source: http://www.agcm.it/trasp-statistiche/doc_download/3287-a440chiusura.html

[35] Source: http://www.agcm.it/trasp-statistiche/doc_download/3287-a440chiusura.html .

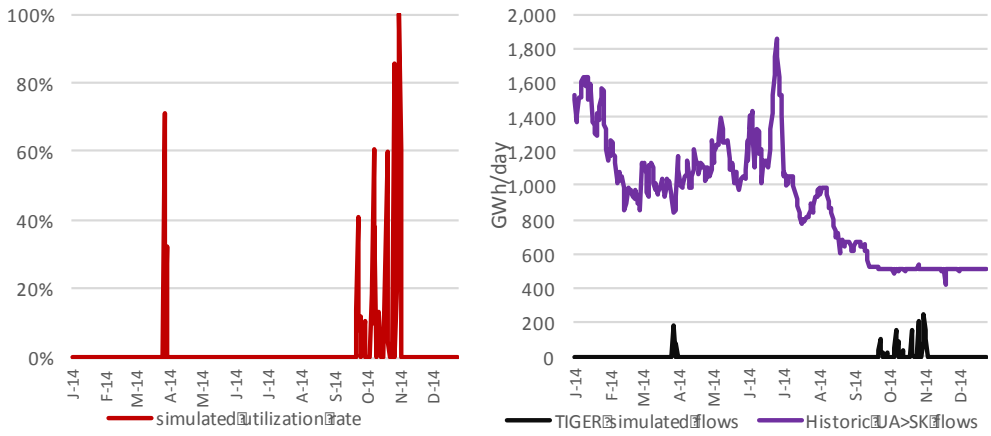
[36] Please refer to Appendix II for an illustrative representation of Oberkappel IP. Note that gas may flow from Austria to Germany passing via Oberkappel IP (technical capacity equal to 159.9 GWh/d), Überackern ABG/ Burghausen IP (technical capacity equal to 54.3 GWh/d) and Überackern SUDAL / Burghausen IP (technical capacity equal to 230.1 GWh/d) (Source: ENTSO-G Capacity Map June 2014). Flows at Überackern ABG/ Burghausen IP and Überackern SUDAL / Burghausen IP are influenced by the fact that they are connected to large gas storage facilities in Austria (please refer to Appendix II for details).

Figure 10: Simulated and historical flows from NCG to CEGH in 2014 (GWh)



Source: EWI TIGER Simulation, ENTSO-G Transparency Platform

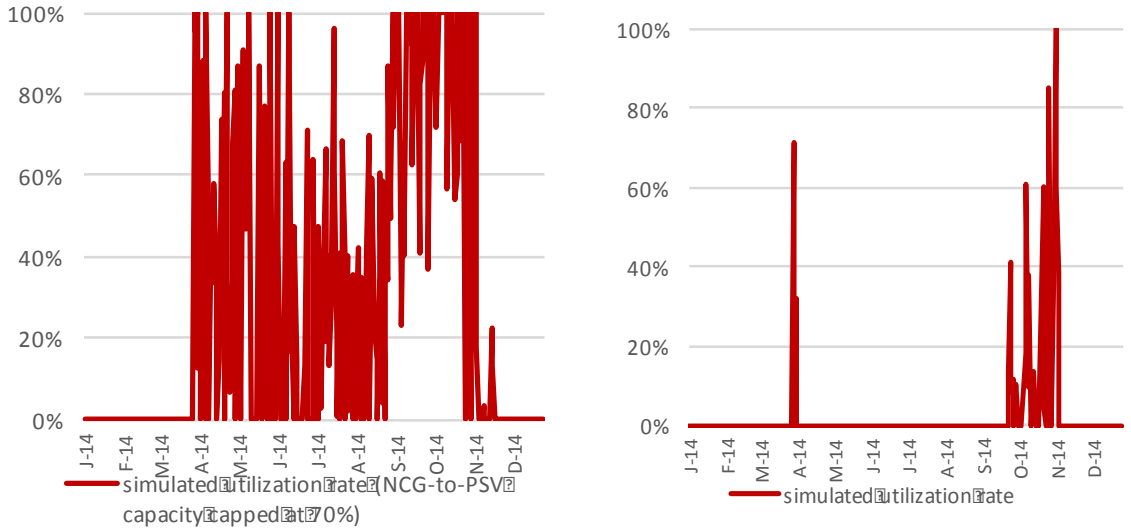
Figure 11: Simulated flows from NCG to CEGH (% firm technical capacity, left; GWh, right) and historical flows between Ukraine and Slovakia in 2014 (GWh, right)



Source: EWI TIGER Simulation, ENTSO-G Transparency Platform

The simulation suggests that the historically observed bottleneck at Oberkappel IP does not emerge because the route from Germany to Switzerland is fully utilized, contrary to what we saw in 2014 (see the analysis presented in Chapter 4.1), alleviating the pressure on the Germany to Austria pipeline route. If we introduce an exogenous constraint that limits the exploitation of the NGC-to-Switzerland pipeline system at 70% of the existing firm technical capacity - trying to reproduce the non-physical barriers to ship gas from North West Europe down to the higher priced Italian market - then the model reproduces the physical bottleneck between Germany and Austria that we witnessed in 2014 (**Figure 12**).

Figure 12: Flows from NCG to CEGH (% firm technical capacity), capping NCG-to-Switzerland transmission capacity at 70% of existing firm technical capacity (left) and without any restriction on NCG-to-Switzerland capacity (right)



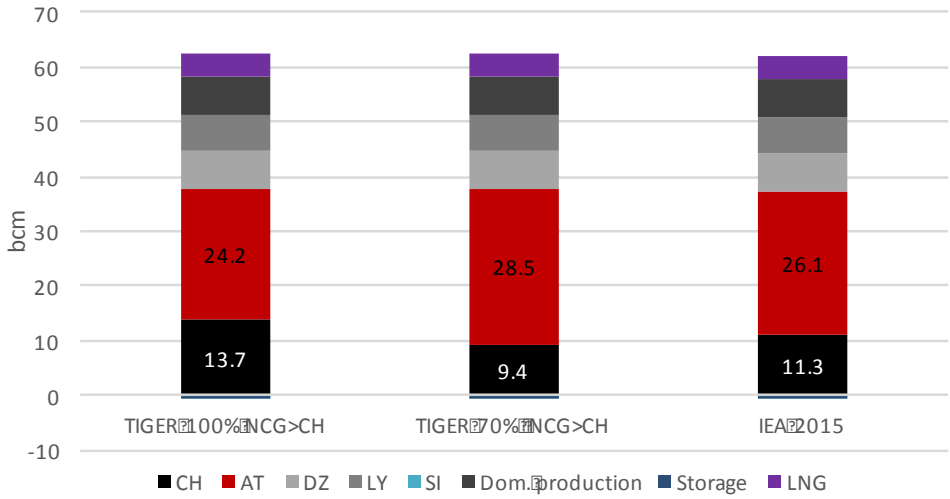
Source: EWI TIGER Simulation, ENTSO-G Transparency Platform

The sensitivity therefore suggests that the heavy utilization rate at Oberkappel IP in the direction from German NCG to the Austrian VTP is linked to gas flows coming from North West Europe that head to Italy and pass through Austria, instead of Switzerland where transit may not be fully exploited. The good price correlation between the Austrian VTP and PSV in 2014, which is stronger than the price correlation between the former and NCG[37], confirms the link between the Austrian and the Italian gas markets.

(Figure 13) shows a comparison of the inflows and outflows for 2014 to Italy from the TIGER simulated sensitivities and historical flows based on IEA (2015). It can be seen that there is a shift of approximately 4 bcm from Swiss transit to Austrian transit to Italy when the capacity from NCG to Switzerland is reduced. The real flows through Austria and Switzerland to Italy were between the values in the TIGER sensitivities, implying that we overestimate the contractual bottleneck by assuming a general 70% cap of the technical capacity.

[37] For details please refer to Petrovich (2015).

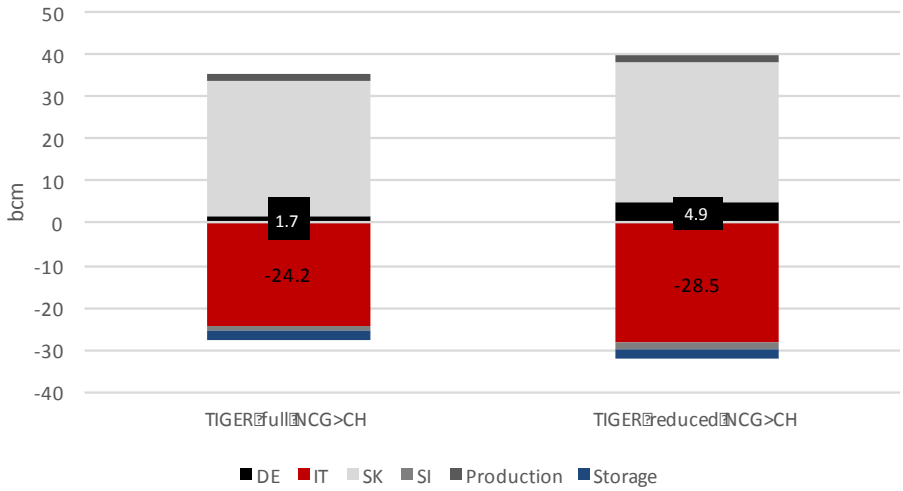
Figure 13: Yearly inflows- and outflows to / from Italy in 2014 in the TIGER simulated sensitivities and in reality



Note: positive values represent inflows into the Italian PSV, negative values represent outflows from the Italian PSV; exports to Slovenia are virtually zero in both historical data and simulation
Source: EWI TIGER Simulation, IEA (2015)

This shift from Swiss transit to Austrian transit to Italy, which occurs when the capacity from NCG to Switzerland is reduced, results in a significant increase in gas imports from German NCG into Austria, which transit through the Austrian VTP and head to Italy (**Figure 14**).

Figure 14: Yearly inflows- and outflows to / from Austria in 2014 in the TIGER simulated sensitivities[38]



Note: positive values represent inflows into the Austria VTP, negative values represent outflows from the Austrian VTP
Source: EWI TIGER Simulation

[38] Note a comparison with IEA (2015) data is not presented in the chart, due to inconsistency in reporting inflows and outflows to the Austrian market between IEA and our methodology.

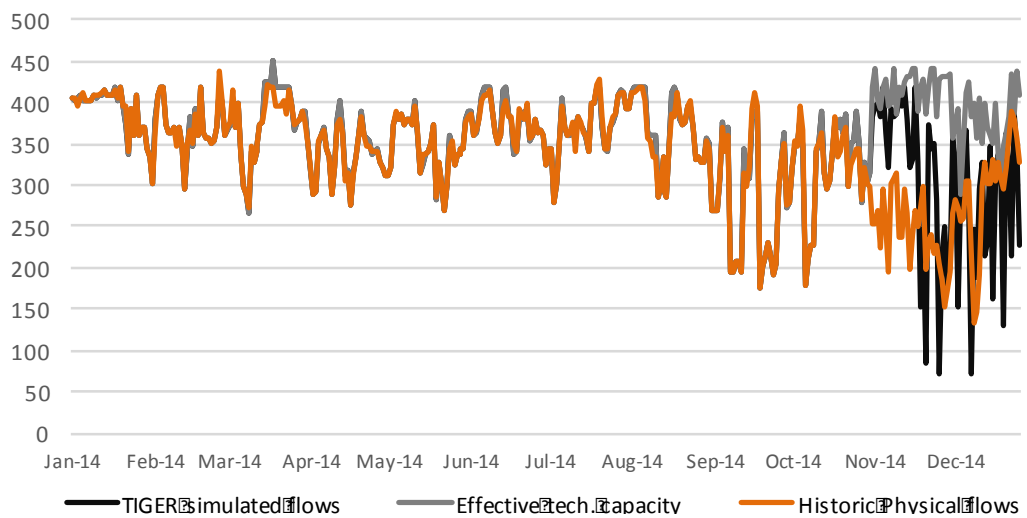
It should be noted here that the Oberkappel IP configuration may favour the emergence of a bottleneck between Germany and Austria due to the disparity between the entry and exit capacities, and pressure in the MEGAL pipeline system in Germany. In fact, in the Germany to Austria direction, at Oberkappel IP the entry capacity to Austria is greater than the exit capacity from Germany (250 GWh/d vs 200 GWh/d[39]). Interruptible capacity is offered by the TSOs operating this IP to reduce the mismatch but it is not enough to solve the bottleneck, also due to pressure constraints in the German system.

Physical transmission capacity between Germany and Austria may be expanded in the future. In particular, the SEL project aims at connecting Überackern-Burghausen IP at the German-Austrian border with the Mannheim area, improving access to the Austrian market area. In particular, the SEL project consists of two sections: the MONACO 1 that ends near Munich and a second line, MONACO II. According to the German Gas Grid Development plan, the SEL project has the potential to strengthen the transit capacity towards Austria[40]. In particular, through the commissioning of the first section of MONACO 1, shippers should have further possibilities for gas transport between the NCG and CEGH[41].

4.3 PEGN to PEGS

Turning to the flows between Northern and Southern France, the model reproduces a very similar pattern to the one we see in historical flows (**Figure 15**): permanent physical congestion until November 2014.

Figure 15: Simulated and historical flows from PEGN to PEGS in 2014 (GWh)



Source: EWI TIGER Simulation, GRTgaz

The emergence of the historically observed French bottleneck in the perfect competition simulation confirms that the disconnection between PEGN and PEGS (and the corresponding price delinkage

[39] Source: firm technical capacity data retrieved from ENTSOG Transparency Platform (data available from Oct-2013 exit from NCG and from October 2014 for entry to Austria).

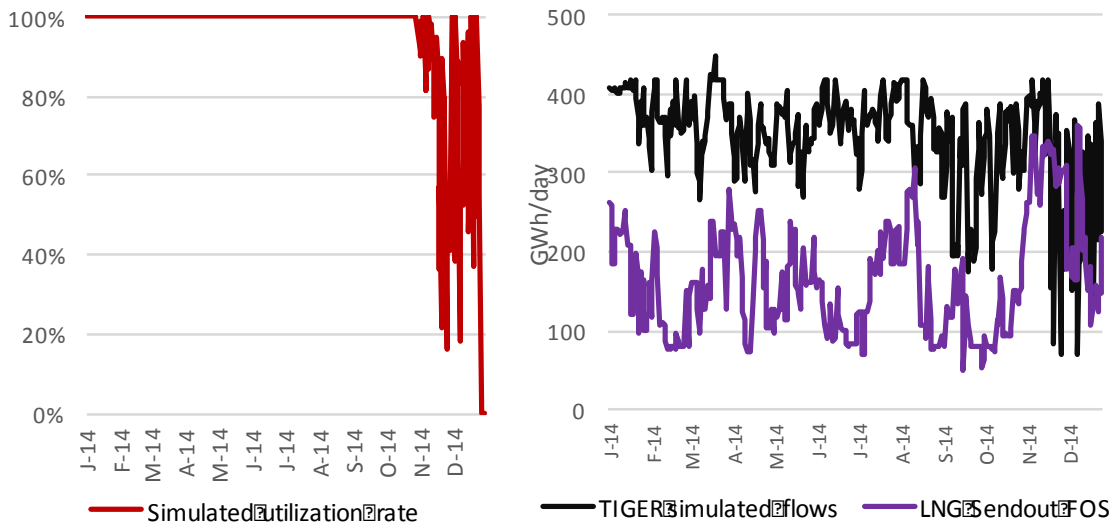
[40] Source: Gas Connect Austria, Coordinated Network Development Plan 2016-2025, Version: 06/07/2015, P.12. Gas Connect Austria (GCA) acts as the market area manager (MAM) in Austria and, pursuant to section 14 para. 1 no. 7 of the Austrian Natural Gas Act, has to draft the Coordinated Network Development Plan (CNDP) in coordination with Austria's transmission system operators (TSOs) for the planning period from 2015 to 2024.

[41] Source: Gas Connect Austria, Coordinated Network Development Plan 2016-2025, Version: 06/07/2015, P.12.

between the two market zones) is linked to insufficient cross border transmission capacity between the two market zones in France, when LNG is scarce in PEGS[42].

Reproducing relatively well what happened in 2014 in the simulation, the bottleneck solves in the two last months of the year, following a peak in LNG sendout from the Fos Caveau regasification terminal located in the South of France, occurring around November 2014. The increased availability of gas in PEGS reduces the need to import from PEGN so alleviating the congestion on the North-South link (**Figure 16**).

Figure 16: Simulated flows from PEGN to PEGS in 2014 (% firm technical capacity, left; GWh, right) and sendout from Fos regasification terminal (GWh, right)



Source: EWI TIGER Simulation, GRTgaz

TIGER simulation also shows that the following factors[43] are key in determining PEGN to PEGS flows and hence congestion between the two zones:

- Send-outs from LNG terminals in the South of France, which are in turn driven by LNG diversion to Asia, as explained in Petrovich (2015),
- Gas exports from the South of France to Spain, which are in turn driven by LNG diversion to Asia and LNG re-loads from Spanish LNG terminals, as explained in Petrovich (2015),
- Tariffs from France to Switzerland: if we assume low tariffs from PEGN to Switzerland, gas is shipped from PEGN to Switzerland (heading to Italy) rather than from PEGN to PEGS[44].

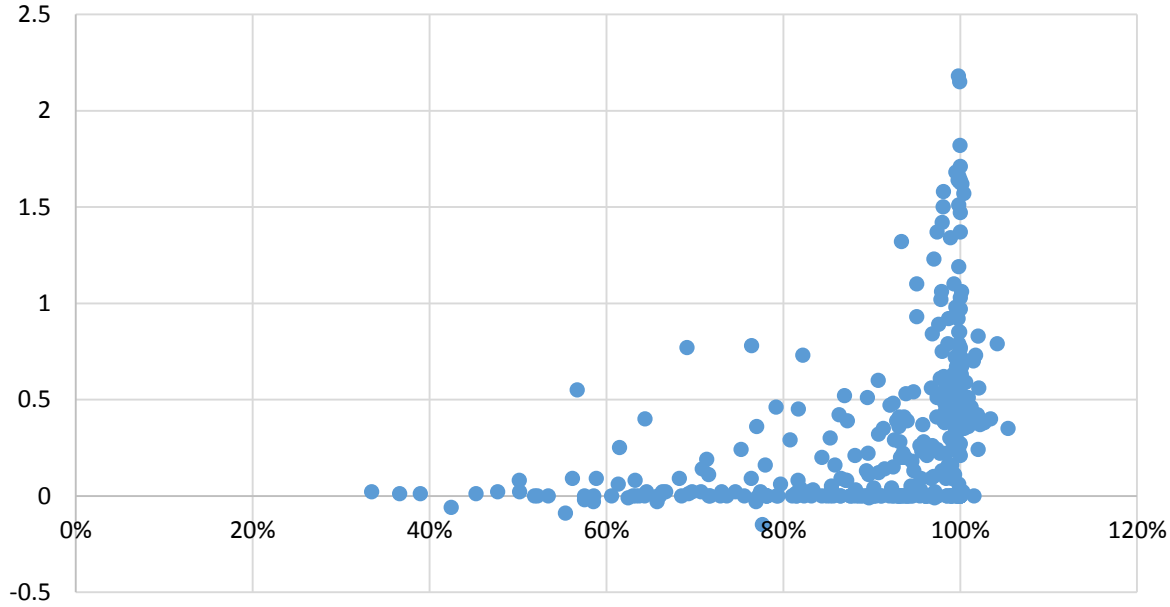
In summary, this result confirms that the nature of the bottleneck between PEGN and PEGS is physical and corroborates the argument that if more transmission capacity was made available in the

[42] PEGS is supplied by pipeline gas arriving from the North and from Southern France LNG terminals (Fos Cavaou and Fos Tokin); PEGS also exports gas to Spain.
[43] In addition to the factors mentioned here it is worth saying that problems in the operational functioning of the N-S link (such as maintenance) can also lead to physical congestion. Problems in the operational functioning are signalled through the ratio between effective available firm capacity on the N-S link and maximum firm technical capacity. In the simulation we fixed firm capacity on the N-S link according to the daily effective available firm capacity as published by GRTgaz.
[44] Swiss tariffs not only impact PEGN to Switzerland exports, but also flows in the NCG-PSV direction.

North to South direction this would most likely favour the creation of a single price for natural gas within France in times of LNG scarcity in the South of France and high exports to Spain.

In fact, looking at historical data for hub prices and the N-S link utilization rate in 2014 and 2015, France displays a virtually single price for spot gas when there is more than 10% capacity free on the N-S link; when the link is physically congested, instead, the premium of PEGS/TRS rises[45]. The positive relationship between the utilization rate of the French link and the day ahead price spread between PEGS/TRS and PEGN is an exponential one: at utilization rates up to 80% it is very rare to observe a price difference between the two French hubs higher than 0.5 €/MWh. For days when the utilization rate is above 80% the spread increases significantly; spreads above 1 €/MWh are observed only for utilization rates above 90% (**Figure 17**).

Figure 17: PEGS-PEGN exchange day ahead spread against utilization rate of the N-S link, direction PEGN to PEGS/TRS, in 2015



Source: GRTgaz, Powernext

The reason for this positive relationship, as discussed in Petrovich (2015, 2016), is that, as long as gas can be moved from PEGN southward (i.e. the N-S link is not physically congested), PEGS prices are in line with those at PEGN because of arbitrage forces; as opposed, at times when the PEGS relies heavily on pipeline gas arriving from the North to balance the network and consequently the N-S link reaches full capacity, the interplay between a somewhat rigid demand for gas and a relatively inelastic LNG supply translates into an increase in PEGS price. Theoretically, when no more gas can be imported from PEGN and other connected liquid hubs in the North, the PEGS price should increase to such a level as is required to attract more expensive alternative tranches of supply (namely additional LNG cargoes) and/or produce demand curtailment. In other words, when PEGS is physically separated from the North, the marginal supply source setting the price becomes LNG shipped to the South of France, either long term contracted LNG above take or pay volumes or spot cargoes.

Different initiatives and plans have been already put forward to expand the transmission capacity from PEGN to PEGS, with the explicit aim to bring PEGS/TRS gas prices back in line with PEGN.

[45] For details on data for hub prices and methodology please refer to Petrovich (2016).

In particular, for the winter 2014/15 backhaul capacity at the Jura interconnection point, located at the Swiss-French border, provided additional access to the French South zone from either Oltingue (PEGN) or Wallbach (NCG) entry points to the Swiss network, provided that the physical flows in the direction from France towards Switzerland are positive. This contractual solution was in fact designed in order to reduce price tension in the South of France; however, despite this attempt, according to GRTgaz, no capacity in the Switzerland to France direction was offered at Jura IP in 2014. This said, capacity at Jura IP accounts for 5 GWh/d, compared to 438 GWh/d firm capacity on the N-S link.

The N-S link remains therefore the main infrastructure linking PEGS to PEGN and, indirectly, other liquid hubs in North West Europe[46]. For this reason, the ENTSOG Ten Year Network Development Plan (TYNDP) 2015 includes projects aiming at the reinforcement of the North-South link: the Arc de Dierrey[47] project and the Val de Saone[48] projects. According to the TYNDP in fact "the purpose of the Val de Saône project (along with the Gascogne-Midi project) is to remove the constraints on North to South gas flows in France, thus enabling to increase the potential share of gas imported by pipelines from the North of Europe within the South-Western part of the European market. In terms of market design, the Val de Saône project allows the creation of a single market area in France. This will bring a final solution to higher prices of gas in South of France and Iberian Peninsula".[49]

Finally, although this is out of the scope of this exercise, it is worth pointing out that, in a global gas market connected by flexible LNG cargoes[50], the spread between European hub gas prices may be cancelled out through arbitrage via LNG, provided that there are no barriers in access to regasification capacity.

In this regard it could be observed that, even when the PEGS price is at a significant premium compared to PEGN, LNG supply remains rather rigid, and the utilization rate of the existing regasification capacity in the South of France remains low (in 2015, the Fos terminals' utilization rate exceeded 60% only in April and September[51]), signalling that there is either no possibility or no incentive to send a spot LNG cargo to the terminal to exploit the differential. The reason for the underutilization of LNG regasification capacity at times when PEGS was physically separated from the North, and priced at a significant premium, was most likely the existence of more attractive resale options (diversion to Asia or indeed re-loading LNG from storage tanks to resell in Asia). Since mid-2014, with the significant drop in Asian LNG spot prices[52], the persistence of a high PEGS premium, an underutilization of the Fos Cavaou and Fos Tokin terminals and relatively high inventory levels in the French LNG facilities may suggest that there are some rigidities/barriers in procuring regasification capacity for spot cargoes and/or maximising send out.

5. Conclusions

Barriers remain to the free trade of gas between some of the main European gas hubs, as shown by recurrent price misalignment between relatively large and mature gas consuming zones: between Northern and Southern France, between Germany and Austria and between North West European hubs and the Italian market.

Our analysis aims to explore the driving forces behind such disconnections, and in particular whether these would be present in a fully competitive setting where all gas suppliers to Europe are price takers

[46] Source: http://www.grtgaz.com/fileadmin/newsletter/shiponline/shiponline_80_site_EN.html
[47] http://www.grtgaz.com/en/press/press-releases/arc-de-dierrey-pipeline.html?fb_locale=fr_FR
[48] http://www.grtgaz.com/en/major-projects/val-de-saone-project/presentation/news/val-de-saone-project.html
[49] Source: sheet "expected benefits" in of annex A in the TYNDP 2015 available at: http://www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2015.
[50] Availability of flexible LNG cargoes is a plausible situation in a global gas market where LNG supply is not tight. For details on scenarios for LNG imports to Europe please refer to Rogers (2015).
[51] Calculation of Southern France regasification terminal usage is based on GIE LNG map and GRTgaz data.
[52] For details on global gas pricing: Rogers (2015).

and the use of cross-border transmission capacity is optimized (i.e. where the existing infrastructure is exploited to the limit to carry out arbitrage activities and the transport costs are minimized).

Our analysis adopts as a benchmark the least cost flow pattern within the European grid determined by the TIGER model created by EWI, for a selected calendar year (2014) once we fix key import/export flows, domestic production and demand at historically observed levels.

By ‘re-running history’, we verified the physical nature of the bottleneck within the French grid and the sub-optimal utilization of transmission capacity on the NCG-Switzerland-Italy route, which in turn contributes to heavy gas flows in the Germany to Austria direction that do not conform to 'pure economic logic' and lead to recurrent disconnection of the Austrian market.

In more detail, the presence of long term shipping contracts on the Transitgas route, difficulties in making transmission capacity available to other participants when not nominated by the original owner and insufficiently flexible capacity allocation procedures appear to be obstacles to shipping gas on a spot basis from Germany to Italy, via Switzerland. However, the confidentiality of shipping contract terms and bookings on this route does not allow to us to establish robust evidence for this argument.

The somewhat limited possibility to fully exploit the Transitgas pipeline system creates a case for shipping gas from the liquid gas markets to Italy through Austria. This alternative route to the PSV puts pressure on the Oberkappel IP and increases the need to ship gas eastward from German via Austria. This situation was exacerbated when the cessation of Russian supply to Ukraine in the second half of 2014 led to substantial reverse (eastward) flow. The request to move significant volumes from NCG to the Austrian VTP led to the saturation of the transmission capacity at Oberkappel and hence to physical congestion between Germany and Austria.

Turning to the French case study, the comparison between reality and simulation for gas flow between the two main French market zones corroborates the argument that if more transmission capacity was made available in the North to South direction this would most likely favour the creation of a single price for natural gas within France in times of LNG scarcity in the South of France and high exports to Spain.

This work complements and corroborates the findings of the price delinkage analysis carried out by OIES to identify the remaining barriers to free trade of natural gas in Europe. Further, it paves the way for projecting this historic analysis into a relevant forward looking exercise. More specifically, a natural follow up would be to use the TIGER model to simulate future bottlenecks in the European gas grid in the possible scenarios for key global gas fundamentals post 2015, as identified by recent OIES research[53].

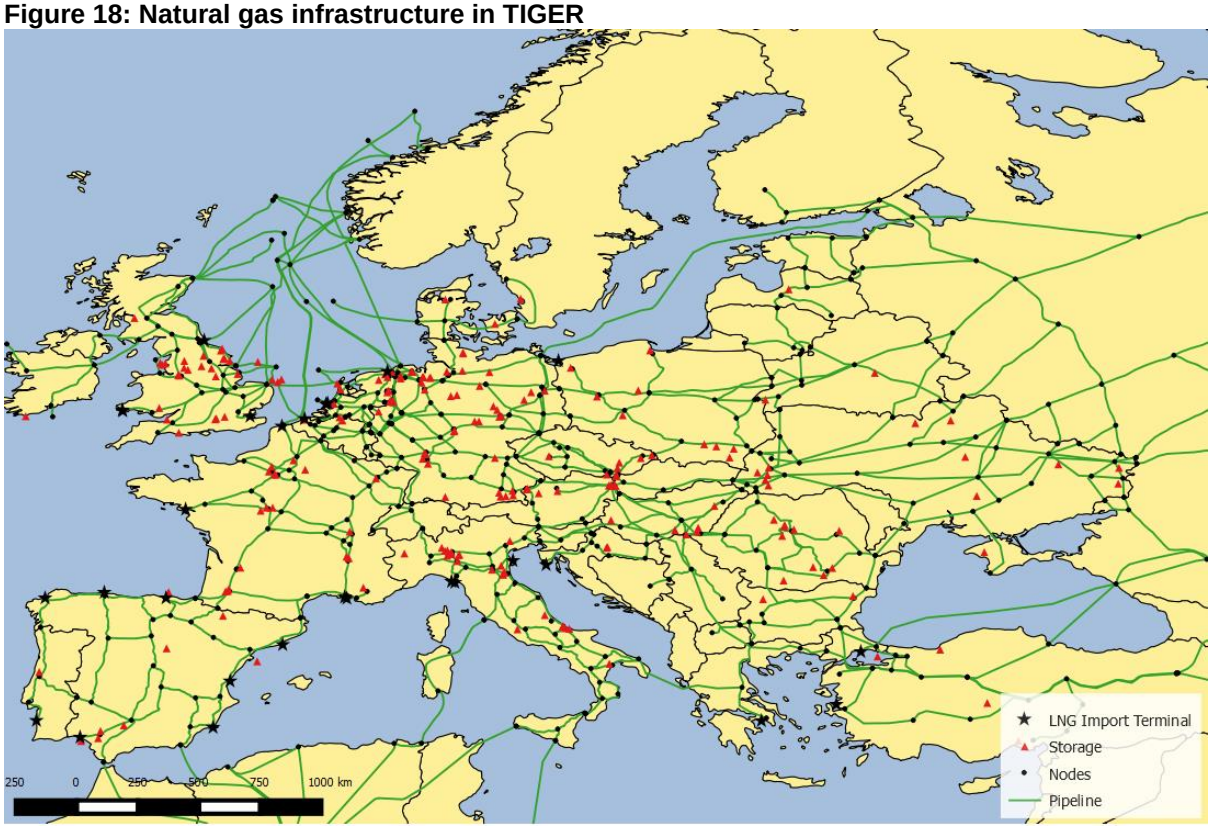
OIES research proved that even in a mature and well integrated European gas market, it may happen that for some periods, as a consequence of changes in gas flow patterns across Europe, a hub may split from the others and display a price dynamic which is completely different compared to the others, possibly resulting in higher costs.

Anticipating the future bottlenecks would help to assess whether there is a case for developing suitable frameworks/incentives aimed at mitigating the potential future factors reducing price integration in the European gas market.

[53] Rogers (2015)

Appendix I: Natural Gas Infrastructure in the TIGER model

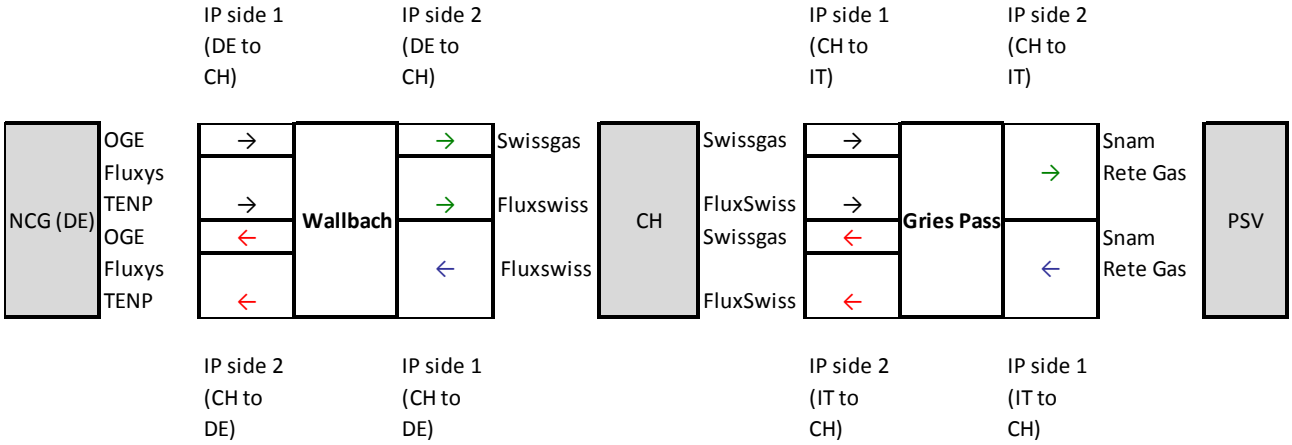
Figure 18: Natural gas infrastructure in TIGER



Source: EWI

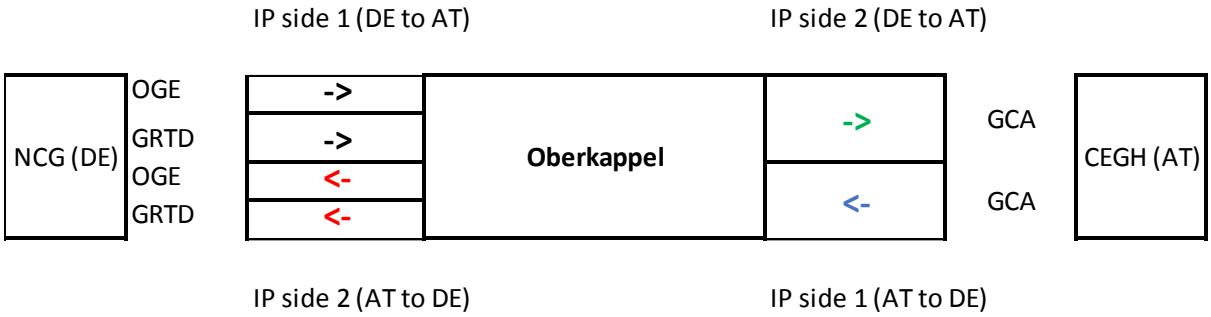
Appendix II: Simplified representation and maps of Wallbach, Gries Pass and Oberkappel IPs

Figure 19: Simplified representation of Wallbach IP and Gries Pass IPs



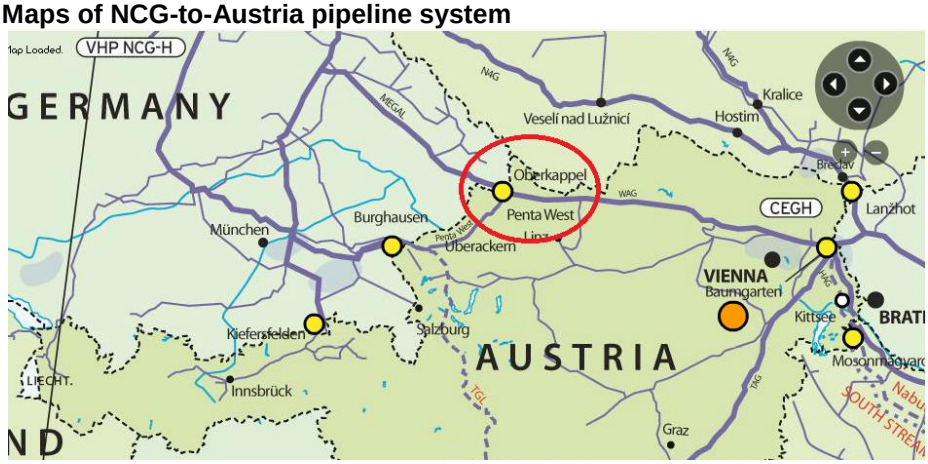
Source: OIES, ENTSOG Capacity Map

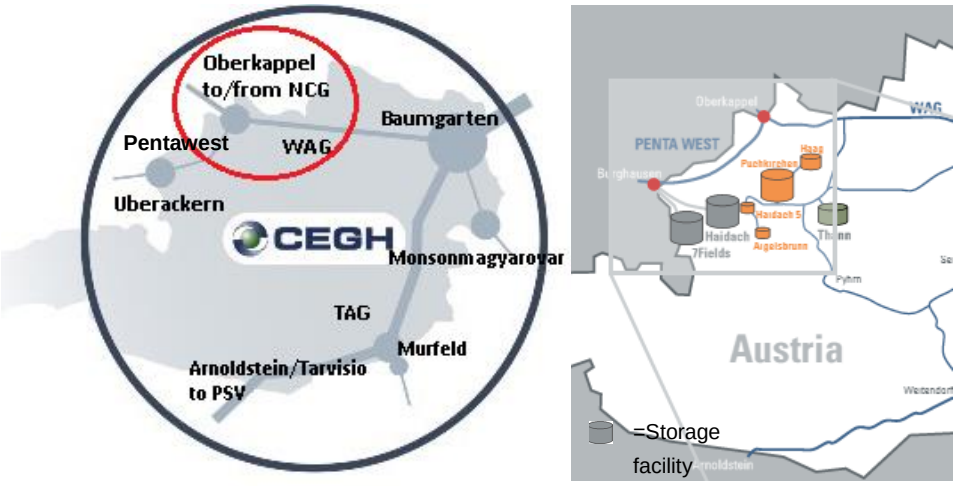
Figure 20: Simplified representation of Oberkappel IP



Source: OIES, ENTSOG Capacity Map

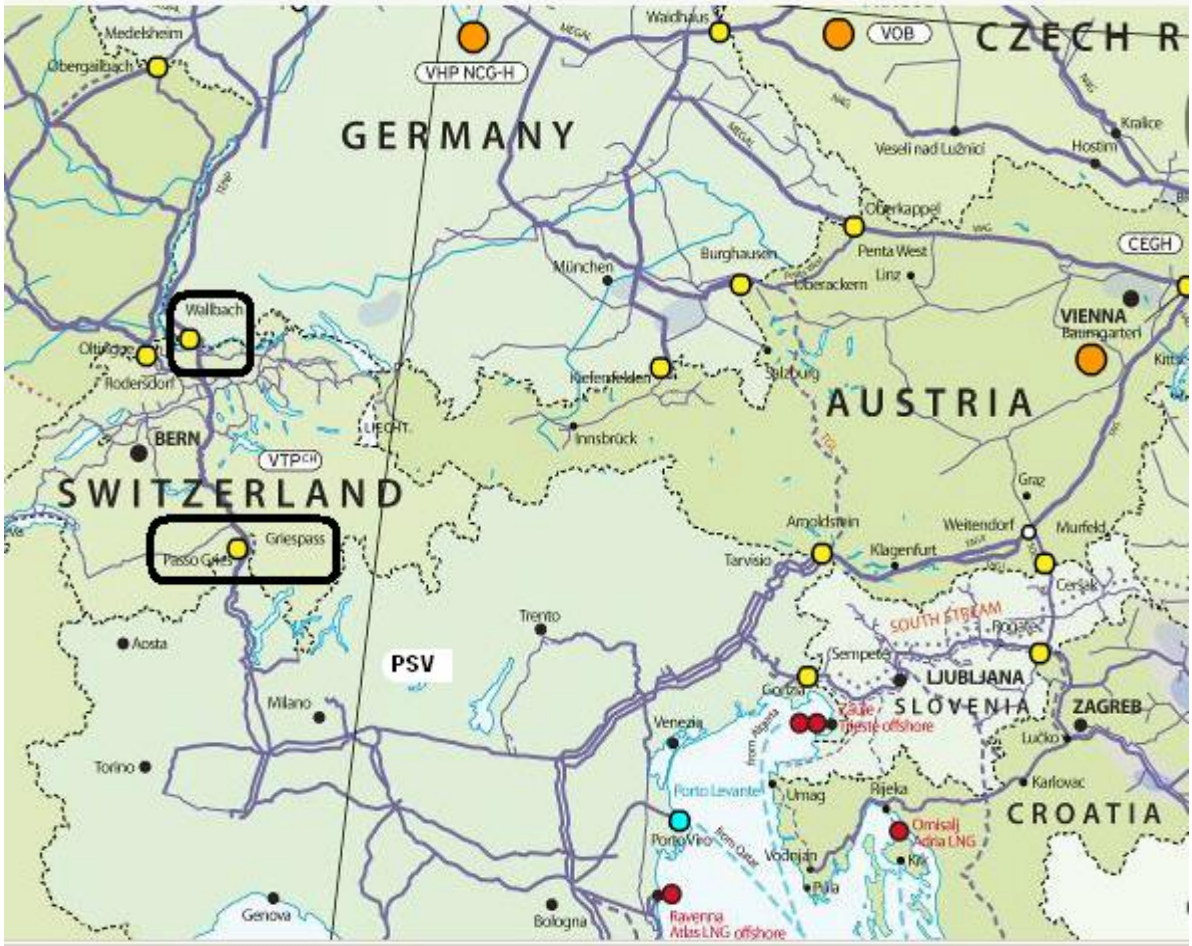
Figure 21: Maps of NCG-to-Austria pipeline system





Source: Transparency platform, CEGH, RAG, authors

Figure 22: Map of NCG-Switzerland-PSV pipeline system



Source: Transparency platform

Glossary

ACER: Agency for the Cooperation of Energy Regulators

Bcm: One billion cubic metres.

Capacity hoarding: an action aiming to prevent access to capacity available on the transport network, deemed as an abuse of dominant position.

CEGH: Central European Gas Hub. For the sake of easy comparison to previous papers by OIES we simply name the Austrian gas hub CEGH. However it should be noted that strictly speaking CEGH is only the name of the exchange operator now, not the name of the trading hub/point, which is VTP. More specifically, with the launch of the new Austrian Gas Act in January 2013, trading within the Austrian market changed from a flange-based system to an Entry/Exit regime and trading activities began to be centralized at the Virtual Trading Point (VTP), which is operated by CEGH. The market operator CEGH offers trading activities and services for different markets: CEGH OTC (over-the-counter) Market, CEGH Gas Exchange Spot Market of Wiener Boerse (Day-Ahead and Within-Day Market), CEGH Gas Exchange Futures Market of Wiener Boerse (Front Month, Quarter, Season, Year), CEGH Czech Gas Exchange in cooperation with PXE (Spot and Futures Market).

CMP: Congestion management procedures

Congestion Management Procedures (CMP) Guidelines: Commission Decision of 24 August 2012 on amending Annex I to Regulation (EC) No 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks (2012/490/EU), OJL 213/16, 28.8.2012

Day ahead (DA) contract/product: Contract for the purchase or sale of gas to be delivered the day after the trading date.

Entry-exit system A system where gas can be traded independently of its location in the pipeline system, with the possibility for network users to book entry and exit capacity independently, creating gas transport through zones instead of along contractual paths.

ENTSOG: Association of European gas TSOs.

GSL: Gaspool, gas hub based in Germany.

GTM (Gas Target Model): Conceptual model for the single European gas markets originally developed by CEER in 2011, and updated in 2015.

GWh: A unit of energy equivalent to a Gigawatt of power for the duration of one hour.

Hub (gas hub): A virtual or physical location within the grid where the exchange of gas volumes takes place. In fact a gas hub is a market for gas, where the commodity is traded on a standardized basis between market participants. In this paper each hub represents a different price area.

Interconnection Point (IP): Means a location, whether it is physical or virtual, between two or more EU Member States as well as between two adjacent entry-exit-systems within the same Member State, where the pipeline systems of the two adjacent Member States or entry exit systems join.

kWh: A unit of energy equivalent to a Kilowatt of power for the duration of one hour.

Long Term Use it or Lose it: see Use it or Lose it

mcm: One million cubic metres.

MWh: A unit of energy equivalent to a Megawatt of power for the duration of one hour.

NBP: National Balancing Point, gas hub based in Great Britain.

NCG: Net Connect Germany, gas hub based in Germany.

OTC (over the counter) trades: Bilateral non-regulated trade however involving standardized physical and financial deals. Such trades are based on standard agreements defining the point of delivery for gas along with other technical and legal terms. They can be for standard volumes of clip sizes of gas and multiples thereof.

PEGN: Point d'Echange de Gaz Nord (Peg North), gas hub based in the North of France, coinciding with the GRTgaz network.

PEGS: Point d'Echange de Gaz Sud (Peg South), gas hub based in the South of France. On April 1, 2015, the PEG TIGF and PEG Sud hubs merged to form a single gas hub to be named Trading Region South (TRS).

PEGT: Point d'Echange de Gaz TIGF (Peg South), gas hub based in the South of France. On April 1, 2015, the PEG TIGF and PEG Sud hubs merged to form a single gas hub to be named Trading Region South (TRS).

Price correlation: When prices move closely in parallel over time.

Price de-linkage: Period of low price correlation.

PSV: Punto di Scambio Virtuale, the Italian gas hub.

TENP: The gas pipeline that runs across German territory from Bocholtz, at the Dutch border, to the Swiss border, close to Wallbach, where it joins Transitgas.

TIGER Model: The European supply-demand transmission model TIGER was developed by EWI at the University of Cologne; it works using as inputs demand, production capacities of major gas suppliers, European domestic production, information on long term contracts, transmission tariffs data and gives as an output a pattern of gas physical flows within Europe. TIGER is a cost minimizing model: the whole system is optimized with regard to the cost for the gas supply, subject to several infrastructure constraints, e. g. capacity limits of pipelines or injection/withdrawal storage curves. For a technical model description, please refer to Lochner (2011).

Transitgas: The gas pipeline that crosses Switzerland from Wallbach at the German border to Passo Gries (Gries Pass) at the Italian border. At Wallbach Transitgas joins the Trans Europa Naturgas Pipeline (TENP), at Passo Gries it joins the Italian network.

Transmission System Operator (TSO): the company responsible for transmission system operation. Some countries have one gas TSO, others have several TSOs.

TRS: Trading Region South, French hub located in the South of France. On April 1, 2015, the PEG TIGF and PEG Sud hubs merged to form a single gas hub to be named Trading Region South (TRS).

TTF: Title Transfer Facility, gas hub based in the Netherlands.

Use-it-or-lose-it (UIOLI): Congestion management provision whereby the transmission capacity which is not nominated (used) by the original owner is made available (lost by the original owner) to other shippers. European rules foresee a "long term" UIOLI and a "day ahead" UIOLI.

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