

The Short and Long Term Impact of Europe's Natural Gas Market on Electricity Markets until 2050

Jan Abrell* and Hannes Weigt**

ABSTRACT

The interdependence of electricity and natural gas is becoming a major energy policy and regulatory issue in all jurisdictions around the world. The increased role of gas fired plants in renewable-based electricity markets and the dependence on natural gas imports make this issue particularly important for the European energy market. In this paper we provide a comprehensive combined analysis of electricity and natural gas infrastructure with an applied focus: We analyze three different scenarios of the long-term European decarbonization pathways, and analyze the interrelation between electricity and natural gas markets on investments in the long run and spatial aspects in the short run.

Keywords: Europe, Electricity Markets, Natural Gas Markets, Networks

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1. INTRODUCTION

The transition of our fossil based electricity systems towards a renewable based system is often linked with natural gas as important transition fuel (EC, 2011a). Flexible combined cycle gas fired power plants are seen as low emitting backup for the transition (EC, 2011b). Naturally, the role of gas in the electricity market strongly depends on the developments on the gas market itself as well as coal and carbon markets. This interrelation is highlighted by the current developments in the European electricity market: despite increasing renewable shares the output of gas fired plants reduced from 462TWh in 2012 to 365TWh in 2014. At the same time the installed gas capacity increased from 193GW to 212GW (ENTSO-E, 2015). This divergence shows the uncertainties involved with respect to the role of gas in electricity systems. Similar changes, but in the other direction take place in the US with the “shale gas revolution” pushing gas plants into and coal out of the electricity market.

In addition, uncertainties on the gas supply side and availability of import capacities, i.e. the Russia-Ukraine conflict and the unstable political conditions in North Africa, have put supply security back on the European political agenda. Some countries and regions within the European Union are dependent on a small number of suppliers, which makes them vulnerable to (temporal) supply disruptions. South European countries (Italy and increasingly Spain) depend on pipeline imports from North Africa (Algeria, Libya) and use liquefied natural gas (LNG) to diversify their supplies. Central and South East European countries import almost exclusively from Russia and

* Swiss Federal Institute of Technology Zürich, Center for Energy Policy and Economics at ETH Zurich, Zürichbergstrasse 18, CH-8032 Zürich, Switzerland. E-mail: jabrell@ethz.ch.

** Corresponding author. Forschungsstelle Nachhaltige Energie- und Wasserversorgung, Wirtschaftswissenschaftliche Fakultät der Universität Basel, Peter Merian-Weg 6, CH-4002 Basel, Switzerland. E-mail: hannes.weigt@unibas.ch; Phone: + 41 61 267 3259; Fax: + 41 61 267 0496.

the current network topology does not allow them to quickly change this import pattern. Storage and reverse flow capacities (to import from the West to the East, opposite the traditional direction from the East / Russia to the West) are put forward as remedies to increase their security of supply, in addition to increasing the number of import routes (Richter and Holz, 2015).

Parallel to the long run uncertainties there is also a strong interdependence on the short time dimension, especially with respect to the spatial availability of gas supplies. An example is the cold spell in continental Europe during winter 2012 sending electricity demand in France to a long-time high of 100 GW. As the export capacity of German nuclear power plants had been shut down following the moratorium after the Fukushima accident gas fired plants in South Germany could have stepped in. However, they could not substitute for the loss of power from the nuclear plants due to a lack of access to natural gas pipeline capacity. At the same time, plenty of natural gas was transported from Austria and South Germany to Italy (EC, 2012). While rolling blackouts have been avoided due to active demand management by the French operators, the issue of electricity-natural gas interdependence was launched and led to a major enquiry by the European Commission.

Summarizing all those relevant aspects in both markets, it becomes evident that a *combined* assessment is needed to derive solid recommendations about the future development of European energy markets. The objective of this paper is to evaluate the feedback effect of different short and long run natural gas market developments on the European electricity market.

Many model based analyses of energy markets either focus on a single sector and aim to be detailed with respect to the underlying market characteristics or they are aggregated energy system models that naturally have to include simplifications on time and spatial dimensions (see e.g. Herbst et al., 2012 for a general energy modeling review).

There is a large stream of literature addressing the development of electricity markets and networks in the wake of an increased share of RES (e.g. Neuhoff et al., 2008; and Egerer et al., this issue). Studies like ECF (2011) and SRU (2010) determine possible development paths for the European electricity system. Investment needs in grid and generation infrastructure, based on renewable targets and potentials, is determined mostly in a cost-minimizing or welfare-maximizing way. Similar, several papers address the market structure and development of the European and global natural gas markets often with a large focus on the Russian-European relations (e.g. Egging et al., 2008, 2010; Dieckhöner et al., 2013). These gas market models have different degrees of spatial network representation and strategic aspects covering optimization and equilibrium models. Depending on their focus those single sector models can either be designed as short term or long term models. However, those models need to account for changes on the respective up-stream or down-stream market impact by adjusting the respective parameters (i.e. gas prices or demand by gas fired electricity plants).

Large scale energy system and macroeconomic models allow keeping those relations endogenous to the model as they cover the interrelation between fuel markets or/and the economy as a whole. However, due to the scale of those models they are typically limited to long term relations. Furthermore, as they have to keep the system representation aggregated they often lack detailed network characteristics. Examples are Capros et al. (1997), Paltsev et al. (2005), Möst and Perlwitz (2009), IPTS (2010), and Capros (2010).

This paper combines bottom up representations of the European electricity and natural gas market and examines the impact of different pathways of European carbon and renewable policy on electricity and natural gas infrastructure. Our approach allows extending the more detailed single market evaluations with an assessment of interaction effects accounting for network aspects, es-

pecially loop flows in the electricity market, seasonal and daily market dynamics, as well as long term investment incentives. Albeit being more simplified in its respective market representations than single market models the results can provide additional insights providing a more comprehensive overall assessment.

The research objective is to evaluate the infrastructure implications of the envisioned European energy transition. Given the coupled nature of our model approach this objective is addressing three related topics: First, the supply security of the European energy system, especially the relation between Russia and Europe. Second, the policy interrelation of Europe with a multitude of energy and environmental objectives and subsequent policies interacting on the markets. And finally, the influence of the vertical relation between and interdependence of energy markets for the future development. To provide a comprehensive evaluation of those topics we perform a three-stage analysis. First, we aim to get a better understanding of the importance of policy and market developments in the electricity-gas nexus by evaluating a selection of different carbon and renewable scenarios using the coupled model. Second, we perform alternative long term gas market scenarios to capture their impact on power plant investments. Finally, we design short run supply shock scenarios to analyze spatial feedbacks towards the electricity system under different power plant configurations

From a methodology point the coupling approach applied in this paper is in line with existing models as the coupling of electricity and gas market models has gained increasing attention in recent years (see e.g. Unsihuy et al., 2007; Rubio et al., 2008; Liu et al., 2009; Damavandi et al., 2011; Duenas et al., 2012; Spiecker, 2013; Erdener et al., 2014). The research focus is largely on the techno-economic short term relation between both markets. Few combined models include endogenous investments (e.g. Geidl and Andersson, 2006; Unsihuy-Vila et al., 2010; Linert and Lochner, 2012; Chaudry et al., 2014; Abrell and Weigt, 2016). Our model follows these approaches to evaluate the future European electricity scenarios by including an endogenous natural gas market representation. In contrast to Abrell and Weigt (2016) the paper at hand is focused on long term market evaluations and the feedback effect from different gas market developments on electricity generation investments.

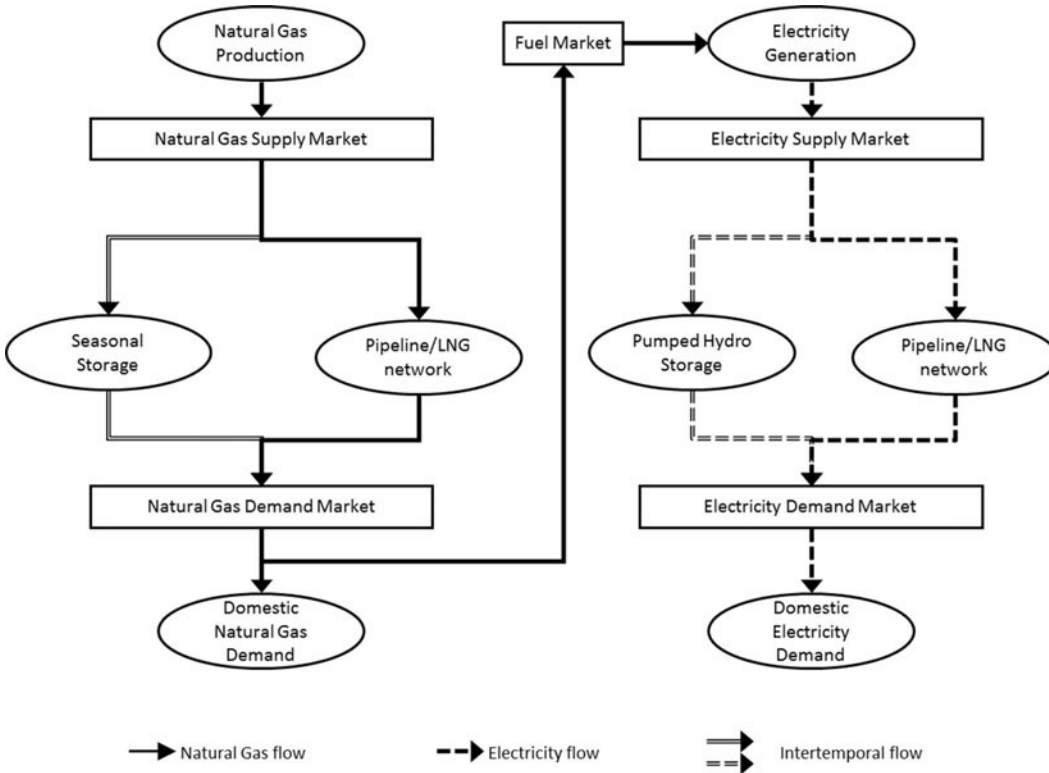
The remainder of this paper is structured as follows. Section 2 presents the combined model and the underlying data. Section 3 provides the central scenario results. Section 4 and 5 present the long and short run feedback effects, respectively. Section 6 summarizes and discusses the main findings and concludes.

2. MODEL AND PARAMETERIZATION

2.1 The model

The model in this paper allows for a combined natural gas and electricity sector representation, both taking into account the respective sector's transmission grid and how they can be run independently of one another or in a combined manner (Figure 1). The natural gas model, which is shown on the left hand side of Figure 1, depicts pipelines, LNG routes, and seasonal storage. The arcs in the pipeline network are directed, i.e. the natural gas flows in a predetermined direction given by the compressor stations in the pipeline network. As we aggregate all cross-border pipelines into one representative pipeline we capture backflow alternatives by using two opposing directed pipelines for each border with respective flow capacities. LNG routes are treated similar to pipelines with the regasification capacity at the receiving node being the pipeline capacity.

Figure 1: Model overview



The electricity model, which is depicted on the right side of Figure 1, includes the transmission grid using a DC-loadflow approach (Schweppe et al., 1988; Leuthold et al., 2012). Electricity generators sell at their respective node while the system operator handles exchange and congestion. Short term storage in form of pumped-storage hydropower allows the transfer of energy between load segments. Contrary to the natural gas market seasonal storage is not possible but daily storage via pumped hydro is feasible.

The two models are then combined by including the fuel linkage: the demand of natural gas fired power plants becomes an endogenous variable in the natural gas model and the natural gas price becomes an endogenous variable in the electricity model.¹

This basic setup is sufficient to capture short term impacts of both systems on each other. In order to evaluate long term effects we include investment alternatives. To keep the model simple and straightforward we limit the endogenous investment to electricity generation. Given that fuel price spreads are the main driver for power plant investment decisions this captures most of the long term feedback effect of gas market developments on electricity markets.

The model formulation is based on Abrell and Weigt (2012, 2016). As we assume perfect competition we transfer the equilibrium formulation into an optimization problem. While the investment approach of Abrell and Weigt (2016) focuses on the trade-off between transporting gas

1. We do not consider further interactions between these markets. E.g., we do not consider the change in final demand for electricity which might occur when gas prices change due to non-zero cross-price elasticities of demand.

or electricity, the applied model formulation of this paper puts the focus on power plant investments. The combined formulation allows endogenizing the feedback effect from natural gas market price dynamics. The formulation as optimization problem allows handling larger datasets while ensuring reasonable computation times and stable solutions.

The objective is to minimize gas production costs (first term, extraction costs c^{gas} and gas production X^{gas}), costs for gas pipeline (second term, pipeline transport costs c^{pipe} and pipeline flow F^{pipe}) and LNG (third term, LNG transport costs c^{LNG} and LNG flow F^{LNG}) transport, electricity generation costs (fourth term, generation costs c^{el} and electricity generation X^{el}) and costs for investing in new power plants (last term, investment costs c^{inv} and installed capacity CAP) over all nodes and all considered periods t given a fixed end-user gas and electricity demand. Flows are defined between two connected nodes n and nn . The costs for electricity generation c^{el} account for fuel input prices and plant efficiency. The exogenous carbon price also enters the electricity generation cost according to the plant efficiency and carbon content of the respective fuel.

$$\min COSTS = \sum_{t,n} c_{t,n}^{gas} X_{t,n}^{gas} + \sum_{t,n,nn} c_{t,n,nn}^{pipe} F_{t,n,nn}^{pipe} + \sum_{t,n,nn} c_{t,n,nn}^{LNG} F_{t,n,nn}^{LNG} + \sum_{t,n} c_{t,n}^{el} X_{t,n}^{el} + \sum_{t,n} c_{t,n}^{inv} CAP_{t,n} \quad (1)$$

Pipelines, LNG routes, and natural gas extraction are subject to capacity constraints. Likewise, electricity generation may not exceed the installed capacity. Flows on the electricity grid are captured by the DC-load flow equations:

$$F_{l,t}^{el} = b_l \Delta_{l,t} \quad (2)$$

$$NI_{n,t} = \sum_l inc_{n,l} F_{l,t}^{el} \quad (3)$$

Power flows (F^{el}) on a line l are defined by the lines susceptance (b) and the voltage angle difference (Δ) between the start and end node of that line. The power flows on each line connecting a node (given by the incidence matrix inc) define the net injection (NI) at that node which in turn is linked to the nodal market clearance (i.e. the nodal energy balance).

Endogenous power plant investments are added to the pre-existing, externally defined generation capacities. The current period's endogenous capacity level CAP_t is defined following a time balance formulation accounting for the new investments in the current period CAP^{NEW} and depreciating those investments that have reached the end of their lifetime LT :

$$CAP_{n,t} = CAP_{n,t-1} + CAP_{n,t}^{NEW} - CAP_{n,t-LT}^{NEW} \quad (4)$$

The storage balance for natural gas and electricity ensures that the current period storage level (S_t) is equal to the pre-period level (S_{t-1}) accounting for withdrawals S^{out} and injections S^{in} including storage losses η . In addition injection, withdrawal and total storage levels are limited by available capacities.

$$S_{n,t} = S_{n,t-1} + \eta S_{n,t}^{in} - S_{n,t}^{out} \quad (5)$$

The two markets have respective nodal market clearing conditions equalizing supply, demand, storage operation and transmission. For the natural gas market the market clearing equation is as follows:

$$X_{t,n}^{gas} + \sum_{nn} F_{t,nn,n}^{pipe/LNG} + S_{n,t}^{out} = d_{n,t}^{gas} + \sum_{nn} F_{t,nn,n}^{pipe/LNG} + S_{n,t}^{in} + \frac{X_{t,n}^{el_gas}}{\eta^{el_gas}}$$

On the supply side we have the production at the respective node (X^{gas}), the gas transported to that node using either pipeline or LNG (F), and withdrawals from the storage located at that node (S^{out}). On the demand side we have the end-user gas demand ($dGAS$), gas transported away from that node (F), injections into the storage facility (S^{in}), and the demand by gas fired power stations given by their electricity output X^{el_gas} and their heat efficiency η^{el_gas} .

The market clearing equation for electricity is similar in structure. Electricity generation (X^{el}) and storage releases (S^{out}) form the supply at a given node. Demand is given via end-user electricity demand (d^{el}) and storage injection (S^{in}). Due to the nature of meshed electricity networks the import/export structure of the gas system is replaced by the respective net injections (NI) which is free in sign and relates to the DC-load flow formulation:

$$X_{t,n}^{el} + S_{n,t}^{out} = d_{n,t}^{el} + S_{n,t}^{in} + NI_{n,t}$$

The law of motion for capacity and storage are intertemporal constraints in the sense that they link subsequent periods. The objective function also accounts for the sum over all periods (neglecting interest rate aspects). Thus, the model described constitutes a dynamic linear optimization problem. As we use different time steps (see next section) the storage aspects in both natural gas and electricity markets account for sub-yearly storage while the capacity extension links different years.

The model is formulated in GAMS (Brooke et al., 2008) and solved using the CPLEX solver. The algorithm minimizes the objective function under the described constraints choosing electricity and natural gas production and storage levels as well as the natural gas flow along pipelines, electricity (net-) injection into the transmission grid and investments into electricity generation capacity. Concerning investments, we only allow for investments into coal and gas-fired generation capacity. The installed capacity for nuclear power and biomass power plants are exogenously given. Likewise the generation of renewable resources, i.e., wind and solar power, is taken as exogenous.

2.2 Data

We model all European countries (excluding the Balkan and Baltic States²) for the period from 2010 to 2050 in five year steps. Each country is aggregated into one node connected to its neighbors via gas pipelines and electricity transmission lines. Most of the country data is provided by the EMF28 scenario dataset including yearly electricity and gas demand, initial power plant capacities, fuel and emission prices, plant efficiencies as well as investment costs (see Weyant et al., 2013, the Appendix provides an overview on those assumptions).

For the gas market we model a monthly resolution. The yearly demand level is allocated to monthly levels using historic data from the Joint Organisations Data Initiative (JODI). Electricity is also modelled in a monthly resolution to capture seasonality. In addition, however, we model representative load segments to capture daily demand profiles. For each month we use six sub-

2. I.e. the model dataset includes the EU15 and Norway and Switzerland, as well as Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia.

quent time segments representing the average load levels of the perspective four-hour blocks. The distribution of yearly demand to the respective time segments is based on historic hourly demand profiles obtained from ENTSO-E. Hourly profiles of wind and solar power injection are collected from websites of the national grid operators. In case the hourly profile is not available, we use monthly profiles provided by ENTSO-E and impose hourly profiles of the most similar neighbor country. Data sources and information on the mapping of the profiles from a neighbor country are documented in Abrell and Rausch (2016).

The electricity network is limited to cross-border connections at the 220kV and 380kV level derived from ENTSO-E. Our model therefore neglects inner country congestion. Likewise the pipeline capacities are the aggregated cross-border capacities from ENTSO-G.

As our gas model is focused on the European system we apply an aggregated approach to represent international natural gas export capacities: In addition to the European nodes the gas system has four virtual nodes; a Russian, an Africa, and a Mediterranean LNG and Atlantic LNG node. Those nodes are connected to respective countries and limited by their respective import capacity; i.e. the African node is connected to Spain and Italy using the Algeria-Spain and Tunis-Italy pipeline capacities as reference. For the LNG connections the respective countries LNG re-gasification capacity is used a limitation for the respective LNG route. Data on LNG capacities and storage capacities is taken from Gas Infrastructure Europe (GIE). The production cost levels at the four export nodes are calibrated to derive a realistic European market price level in 2015 and scaled for later periods following the underlying gas price assumptions (Weyant et al., 2013). Otherwise the nodes are treated equally to European production nodes; i.e. their production and export values are derive by the model based on the cost optimization logic for the overall system. This approach neglects strategic behavior of exporters as well as international market interactions e.g. via LNG with the Asian market. As the export price levels for those nodes are scaled with the gas price assumptions (see Table 5 in the Appendix) the model neglects detailed gas production investment aspects and differentiations between long and short-term price aspects in the gas market.

Network extensions follow the Ten Year Network Development Plans of ENTSO-E and ENTSO-G, again only capturing cross-border extension. In addition, for the European gas pipeline network we assume that all cross-border connections are fully backflow capable by 2030. For gas storage and LNG infrastructure the planned and projected additions provided by GIE are used. Those extensions only capture the timeframe up to 2030. Consequently the transport infrastructure is fixed for all scenarios from 2030 onwards. We rely on IEA's World Energy Outlook to scale European gas production capacities up to 2050 to calibrate future production development.

3. CENTRAL SCENARIOS: BASIC MARKET DEVELOPMENTS

Our scenario analysis proceeds in two steps. First, we analyze the interaction between natural gas and electricity markets under the external assumptions on domestic natural gas and electricity demand, carbon prices and renewable energy deployment (Weyant et al., 2013). These scenarios are denoted as *central scenarios*. We then deepen the analysis by altering the gas market conditions. This is done in two different timeframe works. We first analyze the impact of long-term changes by altering import possibilities (section 4). Specifically we impose enlargements of the import capacities from Russia via different routes and an increase in LNG capacities for cheap North American shale gas resources. Second, we analyze the short-term interaction of the markets by modelling an unforeseen interruption of Russian gas exports (section 5).

We analyze three central scenarios which cover a diverse mix of potential developments and thus the simulated market results span a broad range. For all scenarios the EU 2020 targets are

imposed but the scenarios differ with respect to their targets beyond 2020 and assumptions of technology evolution and energy efficiency:³

- *40%DEF*: “Moderate policy” scenario with a 40% CO₂ emission reduction target for 2050
- *80%DEF*: Similar to *40%DEF* but with a 80% CO₂ emission reduction target for 2050
- *80%GREEN*: Same as *80%DEF* but with a higher share of “green” renewable generation, stronger energy efficiency development and constrained usage of Carbon Capture and Storage (CCS) and nuclear power plants.

An important driver for the investments in either coal or gas power plants is the emission permit price development. In the two *80%* scenarios the price level rises to more than 250€/t in 2050 favoring low emission investments.⁴ Of particular relevance for our coupled market model are also the assumptions on natural gas demand. While all cases show a steady decline of demand for gas outside the electricity sector this trend is significantly more pronounced in the two *80%* scenarios. This will impact the modeled natural gas market prices and therefore the investment decisions taken in the electricity market.

3.1 Result Overview

Table 1 provides an overview of the simulated investments and average market prices. Apparently, significant coal investments will be realized only in the *40%DEF* scenario which is characterized by a moderate emission price of around 50€/t CO₂ from 2035 onwards. High electricity demand and moderate renewable extensions lead to total investments being the highest of all three scenarios (around 240GW, of which 190GW are coal). The general investment patterns in all three scenarios largely follow the imposed decommissioning scenario assumptions. Each period about 30 to 50GW of old gas and coal plants are leaving the market from 2015 onwards till 2045. After the initial overcapacity is reduced we see a first investment spike in 2025 to cover the gap between decommissioning and external additions. 2030 has the lowest decommission level and consequently a modest investment level. From 2035 onwards we see a clear difference between the three scenarios due to the different assumptions on renewable additions and demand increase with the *40%DEF* scenario having consistently high investment levels.

What is interesting to note is the pattern of investments into gas and coal in the *40%DEF* scenario. We can distinguish three phases: First, up to 2030 only coal plants are built, following by a phase of combined coal and gas investments until 2045, and finally back to pure coal investments for 2050. This result is caused by the underlying fuel price assumptions and natural gas market prices. Up to 2030 the low carbon price is pushing gas out of the market. With an increase in carbon prices gas becomes an interesting option albeit parallel to coal. Consequently the two technologies are on relatively equal ground during those years. Respective local price advantages or disadvantages and running times play an important role which investment is favored. In the final period coal is on an advantage again. Albeit the carbon price and coal prices remain high they don't increase

3. Table 5 in the Appendix provides an overview on the different underlying market assumptions.

4. The 80% targets are overall emission objectives and translate into higher emission reductions for the electricity sector. However, as our model has no endogenous emission cap the carbon price is the sole influence on generation and investment decisions. Feedback effects of the resulting electricity sector emissions are consequently neglected.

Table 1: Result overview base developments

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
<i>Coal Investments [MW]</i>										
40%DEF	—	—	1,350	5,661	34,390	2,055	25,831	40,273	59,977	18,197
80%DEF	—	1,912	—	—	—	—	—	—	—	—
80%GREEN	—	1,548	—	458	—	—	—	—	—	—
<i>Gas Investments [MW]</i>										
40%DEF	—	735	351	—	—	127	25,204	13,226	14,218	—
80%DEF	—	1,235	1,521	—	12,889	6,046	39,398	31,900	19,945	1,396
80%GREEN	—	1,227	1,535	—	12,430	2,425	15,023	1,236	9,167	898
<i>Average European Electricity Price [€/MWh]</i>										
40%DEF	27.2	38.7	42.6	54.9	67.6	77.8	88.0	89.5	88.9	89.9
80%DEF	28.9	44.7	44.3	56.6	74.0	66.4	76.9	74.4	79.1	79.6
80%GREEN	28.9	44.8	44.6	56.1	69.8	53.0	65.0	41.5	29.6	20.0
<i>Average European Natural Gas Price [€/MWh]</i>										
40%DEF	21.6	21.5	25.5	33.8	40.9	42.6	46.2	49.6	53.4	57.9
80%DEF	21.6	25.4	25.5	33.7	36.9	34.6	35.3	33.2	30.5	30.3
80%GREEN	21.6	25.4	25.5	33.7	36.9	34.5	35.1	33.1	30.5	29.6

that much from their 2035 levels while gas prices increase by roughly 25% in the same timeframe. This pushes coal back below the long run costs of gas.

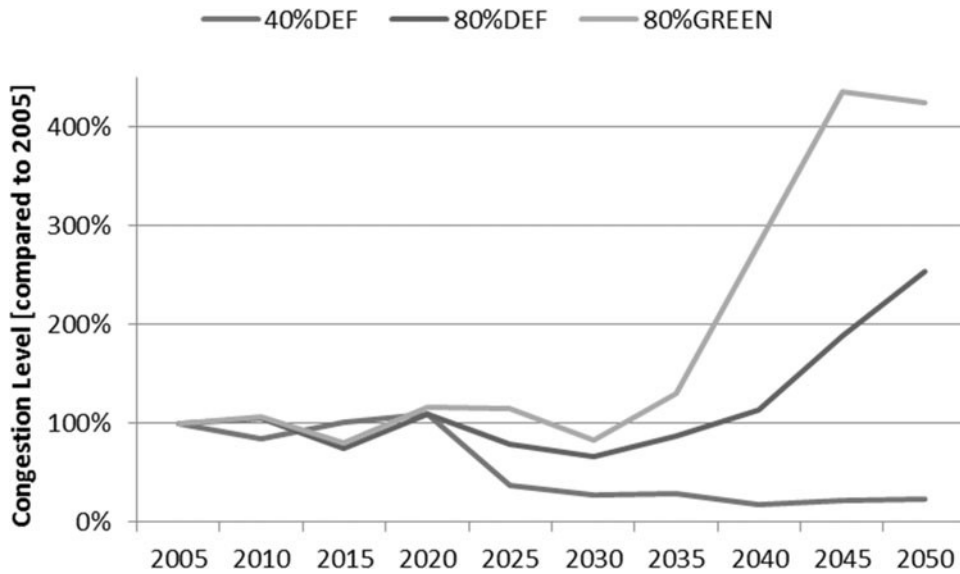
In both 80% scenarios, investments in gas fired power plants dominate. The 80%DEF scenario installs a total of around 115GW whereas the GREEN scenario shows only around 45GW. This significant lower need for new capacities both between the 40% and 80% cases and the DEF and GREEN case is based on the lower electricity demand level and higher RES capacities. The changed renewable and demand development also leads to a significantly altered electricity price development. Whereas the 80%DEF scenario shows a steady price decline from 2025 onwards but remains in on a modest average price level of ca. 80€/MWh across regions in 2050, the 80%GREEN scenario shows a stronger price decline reaching less than 30€/MWh on average in 2045 and 2050. As both nuclear and renewable capacities are external parameter assumptions those price levels are likely insufficient to refinance those investments. However, the price levels are sufficient to cover the cost of the endogenous investments into gas-fired power plants. Prices in hours when gas fired generation is needed to satisfy demand are significant above average price levels reaching peaks above 100€/MWh.

As we scale the 2005 base production cost level in our natural gas sub-model with the respective scenario's external gas price development, the differences in natural gas price paths are again largely driven by our scenario assumptions. A more detailed evaluation of our natural gas market results is provided in Section 3.3.

3.2 Electricity Market Results: Congestion and Impact of Renewables

We now have a closer look at the electricity market results. The focus lies on the impact of limited network capacities in the different scenarios and the role of renewables in shaping the future European electricity market.

For all central scenarios we assume that the ENTSO-E TYNDP is going to be realized up to 2030 but do not include any further network investments from 2030 onwards. Consequently, any

Figure 2: Congestion development

long term changes in the system that are not yet anticipated in the current network investment plans will lead to potential congestion in our model. Figure 2 highlights this development for the different scenarios. Using the congestion level in 2005 as benchmark⁵ we can see a significant decline of congestion in the *40%DEF* scenario from 2020 onwards when the first TYNDP projects are included in our network model.

Contrary, in the *80%* scenarios the congestion levels increase from 2030 onward. In the *80%DEF* case congestion more than doubles while in the *80%GREEN* congestion even quadruples compared to the 2005 level. In both cases the demand and price level is lower than in the *40%DEF* scenario: however, the congestion value is defined by the price differences between countries and not the absolute price level. In the *40%DEF* scenario the average prices in European countries converge up to 2050—albeit on a high level—leading to a reduction of the average price differences of European prices of more than 10€/MWh in the early years to less than 3€/MWh in 2050. In both *80%* scenarios the average price difference between countries increase to about 30€/MWh until 2030. This is a result of the renewable shares based on the scenarios assumptions. In countries with a high renewable capacities the price decreases leading to higher price differences as long as export capacities are not increased. This effect is naturally most pronounced in 2050 in the scenario with the highest renewable generation (*80%GREEN*). For example, Italy requires imports during night time as their local solar capacities are not providing energy. The price level in Italy jumps to the long run marginal costs of the endogenous gas plant investments. At the same time the exporting

5. To derive the congestion level we sum the shadow prices associated to the transmission capacity constraints. This shadow price represents the potential gain in case of a marginal increase in transmission capacity on the respective link. As this depends on generation cost level the metric is bound to increase over time with rising fuel prices all or other things being equal. In addition the measure does not account for cross-effects between congestion; i.e. relieving congestion on one line likely reduces the shadow prices on other constraints. Consequently, the measure is likely to overstate the actual extend of capacity constraints in the system. Similar the measure does not provide insights whether the constraints can easily be relieved or if they represent concrete dispatch problems.

neighboring countries remain on low price levels due to sufficient renewable generation leading to a significant price gap between Italy and its neighbors.

In general, the higher share of RES generation in the 80% scenarios leads to price reductions in Southern European countries during daytimes reflecting the high shares of solar generation. Northern countries like the UK, Norway, Sweden and Finland, also show lower average price levels due to high wind, biomass and hydro generation.⁶ On the other hand, the Central European region is characterized by higher price levels than the European border regions in many later periods. This price divergence is a result of the network extension plans. The meshed grid in the Central European regions is significantly extended with the TYNDP and many different connection paths allow a relatively free exchange of energy. Contrary the connections with border regions have the characteristics of a directed point-to-point line. Europe could thus be considered a big star like electricity system with Central Europe forming a big hub with equalized prices. Due to the isolation of the border regions the likelihood of excess renewable generation pushing prices down is higher than in the central hub where neighboring countries can utilize local renewable surplus.

The congestion results also indicate that the current ENTSO-E TYNDP is designed with a market development in mind that resembles the “moderate policy” assumptions of the 40%DEF scenario. Significant long term alterations will require further adjustments of the European network beyond those if target RES shares rise above 50%.

3.3 Natural Gas Market Results: Imports and Storage

We now turn to the natural gas market results. The focus lies on the import structure within Europe and seasonal storage of natural gas. Table 2 provides an overview on the production and import situation in the different scenarios. For all central scenarios we assume an absolute reduction of European natural gas production following the World Energy Outlook (see Section 2.2). However, given the different assumptions on the development of natural gas demand in the central scenarios the subsequent impact on the European import situation varies greatly.

In general, Europe's relative import share increases in the 40%DEF scenario, only. The reduced European production capacities need to be compensated by imports mainly coming from Russia. The total share of Russian imports therefore increase to 46% in 2050. Alternative import channels only cover a minority of European gas demand. However, this only represents the actual physical flows based on the underlying production price assumptions and not the total available import options. Especially the LNG price dynamics are only represented in a simplified manner. Therefore, the high share of Russian gas is also a result of the assumed cost advantage of Russian gas. In total large LNG capacities at the Mediterranean and Atlantic coasts are not utilized in the 40%DEF scenario and could allow a reallocation of European imports in case of different global price dynamics. Consequently, the European import dependency is coupled with a relative high degree of import flexibility. Whether this will be sufficient to compensate shortages will be tested in Section 5.

The two 80% scenarios assume a significant lower gas demand which translates into a general lower import dependency and a higher share of indigenous production. This is most pronounced in the GREEN scenario in which the same European production capacities as in the 40%DEF scenario are able to satisfy more than 70% of Europe's demand. In addition, the existing import corridors and LNG regasification capacities are mostly not fully utilized. Therefore, the

6. Note that we assume an average wind profile.

Table 2: Natural Gas production and imports

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
<i>40%DEF</i>										
European	54%	55%	55%	49%	47%	46%	45%	46%	45%	44%
Russia	28%	28%	30%	37%	39%	39%	40%	40%	45%	46%
LNGAtlantic	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
LNGMedit	13%	13%	6%	8%	3%	3%	3%	3%	2%	3%
Africa	4%	4%	9%	5%	10%	10%	11%	11%	6%	6%
<i>80%DEF</i>										
European	54%	58%	55%	55%	49%	47%	43%	44%	47%	55%
Russia	28%	28%	30%	30%	36%	38%	42%	40%	38%	32%
LNGAtlantic	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
LNGMedit	13%	6%	6%	8%	9%	8%	9%	9%	8%	4%
Africa	4%	8%	9%	6%	6%	6%	5%	6%	7%	8%
<i>80%GREEN</i>										
European	54%	58%	55%	55%	49%	51%	50%	57%	61%	72%
Russia	28%	28%	30%	31%	36%	34%	35%	29%	27%	16%
LNGAtlantic	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
LNGMedit	13%	6%	6%	8%	9%	8%	7%	5%	3%	1%
Africa	4%	8%	9%	6%	6%	6%	6%	8%	8%	10%

European natural gas market will exhibit a high degree of supply diversification possibilities in the two *80%* scenarios.

These developments also impact the utilization of natural gas storage facilities. Whereas the storage levels and seasonal pattern does not alter much in the *40%DEF* scenario, storage levels significantly reduce in the *80%* scenarios in later years. The general underutilization of both storage capacities but also inner European gas pipelines poses the question whether large scale gas infrastructure investment will really be needed if Europe follows a more stringent emission and renewable policy.

3.4 Summary

The general results already show the impact of varying policy and market developments on both electricity and natural gas markets. In the most relaxed policy constraints scenario (*40%DEF*) the high gas demand leads to a rather tight gas market with high import dependency. But on the other hand the low carbon price keeps coal the dominant fossil fuel. In case of a more restrictive emission policy (*80%DEF*) the role of gas fired generation in electricity becomes much more dominant. At the same time the assumed reduced direct gas demand relaxes the import situation and frees up gas transport capacities. At this point it is hard to predict which scenario setup will lead to a stronger impact of gas market developments on the electricity market as the two described effects are likely to have opposing directions.

The underlying assumptions of the *80%GREEN* scenario are likely to lead to less feedback effects between gas and electricity markets. The investments in gas fired generation are rather modest due to the high renewable shares and low electricity demand level while at the same time the relaxation of the natural gas market conditions due to demand reduction are leading to significant underutilization in European gas transmission and storage facilities.

4. LONG TERM INTERACTION: THE IMPACT OF NATURAL GAS MARKET DEVELOPMENTS ON POWER PLANT INVESTMENTS

As is obvious from the central scenario simulations, the external market assumptions have a strong impact on the resulting investment behavior in the electricity market. The scenarios so far covered generic market price developments on the natural gas market but neglected spatial differentiated developments. Following, we test two diverging potential future developments that impact the European natural gas market and test their feedback effect on power plant investments. First, a change on the supply structure of Russian import channels and second an emergence of significant LNG export capacities of cheap North American shale gas resources.

4.1 Russian Import Corridors

The Russian ambitions to obtain direct import connections to Central Europe bypassing East European transit countries has been an important scientific and political topic even before the emergence of the conflict between Russia and the Ukraine and Turkey. Projects like the already realized Nord Stream or the discussed South Stream and Turkish Stream alter the main import corridors within Europe and naturally have a big impact on prices in the gas market. Most evaluations have either been focused on strategic aspects of the pipeline projects (see e.g. Hubert and Ikonnikova, 2011; and Cobanli and Hubert, 2014) or security of supply and market conditions under different import scenarios (see e.g. Dieckhöner et al., 2013). Using the coupled market model, we evaluate the impact of different import routes on European power plant investments.

Given the ongoing debate on potential corridors for Russian gas we focus on two alternative routes representing the two main import corridors: first, an extension of the already existing Nord Stream pipeline termed Nord Stream 2, and second, a Southern import corridor in line with the originally planned South Stream project.⁷ The two cases are meant to represent specific changes in market conditions and are not an exact recreation of the underlying projects. The Nord Stream case represents a significant increase of available Russian gas in Central Europe (a doubling of the 2015 exchange capacities between Russia and Germany) and thereby directly competing with gas production from the North Sea. The South Stream provides an increased supply for South East Europe (direct pipeline connection from Russia to Bulgaria providing similar capacities like Nord Stream) and imports towards Austria and Italy (ca. 10bcm per year each). Both projects are incorporated into the model in 2020 before the major power plant investments take place by increasing the respective pipeline capacities. We do not assume any predefined export volumes or contractual obligations associated to the new pipelines; i.e. all resulting flow patterns are endogenous following the same general competitive market formulation presented in Section 2.1. Furthermore, we assume that Russia has sufficient extraction capacities to fully utilize its export pipelines.

On the gas market both projects have a minor impact on the price levels. The Nord Stream 2 project increases the gas availability in Central Europe but the price is only reduced by 0.1€/MWh, less than 1% of the gas price. The effect diminishes even more in the 80% cases. The South Stream project provides about 1€/MWh of price reduction in South-East Europe. Overall the impact is extremely modest.

7. See <http://www.nord-stream2.com/> and <http://www.south-stream-transport.com/> for respective information on the projects, as well as the Turkstream project <http://www.turkstream.info/>. The projects are included in a simplified manner and do not capture the full project structure as especially the exact development of the southern pipeline extension is in flux.

This modest result is a consequence of two underlying model and market aspects. First, as the market prices are defined by marginal supplier a change in flow and supply patterns will only have a large price impact if a change in import structures leads to a shift of the marginal supplier. This is not the case with the two Russian extensions. Although, the overall flow pattern is impacted the same marginal price setters are relevant after the extensions in the different European regions. This limits the price impact despite absolute changes in import patterns.

Second, our model neglects strategic behavior. Consequently, a potential gaming of different import corridors and exploitation of transport capacities is not possible. Basically, our model provides the competitive benchmark results for the European gas market. In this regard the limited impact shows that technically the European gas infrastructure is sufficient.⁸

Given the minimal impact on the natural gas market the feedback effect on the electricity market is equally small. In the Nord Stream 2 case the change in investments is highest in *40%DEF* scenario with about 400MW of reallocated gas investment in the UK and France. However, compared to the overall investment volume of 240GW the levels are within the model error range. For both *80%* scenarios no change is observable. The results in case of the South Stream extension are similar with some reallocation of gas investments in Greece and France and basically no change in the *80%* scenarios.

4.2 Shale Gas and LNG

Beside the relation between Europe and Russia the emergence of unconventional gas and the increase of US gas production have induced a global trade shift. The expectations that the US will become import dependent have not materialized and today the debate is about US LNG exports and not imports. While the so far limited exchange capacities from the US to other markets have led to the price separation between North American, European and Asian gas markets, increasing LNG capacities could reverse this trend and lead to a renewed price convergence.

To test the impact an emergence of cheap US shale gas LNG export capacities would have on European gas markets and subsequent electricity investments we increase the respective European LNG import capacities on the Atlantic side by 20% from 2020 onwards. Furthermore, the virtual supply price of LNG from the Atlantic is reduced by 20%. Again the case is not meant to represent specific real world projects but intended to highlight the impact a significant reallocation of gas import options would have on European energy markets.

Contrary to the Russian scenarios above, the availability and assumed price reduction of LNG imports leads to significant gas price reduction in Western and Central Europe while as Eastern Europe is only marginally affected. Prices in Central-Western Europe are reduced by 5 to 10% in the *40%DEF* scenario and about 10% in the two *80%* scenarios. On the import side the LNG imports from the Atlantic basin increase tremendously and compensate a reduced import from Russia and Mediterranean LNG routes.

The price reduction has feedback effects on the electricity market and the subsequent power plant investments. Table 3 summarizes the changed investment patterns in comparison to the respective central scenarios on a regional level. In the *40%DEF* scenario we see a reallocation of coal towards gas plant investments of about 18.7GW. The spatial distribution of those reallocations follows the gas market dynamics: Additional gas plants are invested along the Western countries, especially France, the Netherlands, and Portugal, while at the same time gas investments in Poland

8. Note that we assume full reverse flow capabilities from 2030 onwards.

Table 3: Altered power plant investment in relation to central scenarios, in MW

	40%DEF		80%DEF		80%GREEN	
	Coal	Gas	Coal	Gas	Coal	Gas
N-Europe	+ 51	+ 5317	—	+ 541	—	—
E-Europe	+ 4877	−10750	—	−6301	—	−1952
CW-Europe	−19409	+ 20875	—	+ 6684	−458	+ 2284
S-Europe	−5793	+ 3240	−266	−658	—	+ 1

and Slovakia are reduced. In addition, coal plant investment in Western countries are reduced while investments in Poland and Slovakia increase.

Although, the price reduction is more pronounced in the two 80% scenarios we do not find any significant impact on total gas power plant investment. This divergence to the 40%DEF scenario can easily be explained by the fact that already in the central scenarios nearly no coal plant investments took place. Thus, there is no space for additional gas investments. However, the spatial distribution of those gas plants is indeed impacted by the available of cheap LNG supplies in Western Europe (Table 3). We observe a reallocation from Central-Eastern countries (Austria, Czech Republic, Poland, and Slovakia) towards Germany, the Netherlands, and Switzerland in both 80% cases albeit on different absolute levels.

4.3 Conclusion on Long Term Interaction

The results of the two long term sensitivities show that spatial developments on the natural gas market can indeed have significant impact on the electricity market. Naturally, the main driving force are price impacts. This is highlighted by the LNG sensitivity. Given the reduction in gas prices in Western European countries we can see a subsequent reallocation of plant investments. In the Russian sensitivity we observe no significant price impact and consequently also no impact on investment decisions.

The results also show the impact of market and policy developments on this feedback structure. The two 80% scenarios typically show much weaker feedback structures which is a result of the more relaxed gas market conditions due to the scenario assumptions. Contrary to the central scenarios this conclusion now also can be drawn for the 80%DEF scenario and not only the 80%GREEN scenario. In the 40%DEF scenario the importance of gas and coal plants for the European electricity market makes feedback effects more likely as this allows a reallocation of investments across types. In the two 80% scenarios this reallocation is limited to spatial decision.

5. SHORT TERM INTERACTION: THE IMPACT OF NATURAL GAS SUPPLY INTERRUPTIONS

While long term trends on markets are important for investment decision, short term deviations on the gas market can also lead to deviations on the electricity market. Given that the dispatch decision in electricity markets is based on the merit order of power plants which in turn are based on input prices, short price deviations can lead to changes in this merit order and thereby the plant dispatch. Due to the meshed nature of Europe's electricity markets local deviations can lead to feedback effects throughout the system. Following we will conduct a second sensitivity

evaluation to test how the central scenarios can cope with supply shocks on the gas market and whether and how they feedback to the electricity market.

5.1 Russian Supply Shock

The increasing reliance of Europe on imports on Russia has raised concerns about security of supply not only in the long run but also with respect to short term system and storage management. Even before the emergence of the Ukrainian crisis in 2014, the supply disruptions in 2006 and 2009 following the gas disputes between Russia and Ukraine have already highlighted the importance of a coordinated system management within the European gas market. Backflow options will play an important role allowing to distribute gas more freely in different flow directions.

In order to test the system stability we use the results of the central scenarios (Section 3) as given and assume an unexpected supply shock. We focus on 2030 as the two 80% scenarios show a high overcapacity of the natural gas system for later periods. The shock consists of a transit interruption on the Russian-Belarus and Russian-Ukraine connections during February and March leaving only 25% of the initial transit capacity available on those routes. The direct connection to Germany via Nord Stream is unaffected. To model an unforeseen supply disruption while keeping a deterministic model formulation we fix the storage levels before the shock to the central scenario results. Similar no new investments beyond the central scenario levels are allowed.

Table 4 provides an overview of the aggregated results. First, we can note that the disrupted Russian supply is compensated by imports from other suppliers, namely LNG and African production. In the two 80% scenarios the share of African gas significantly increases as in the base case African supplies are not fully utilized leaving space for short term import increases. In the 40%DEF scenario the import volumes from Africa are already close to their maximum leaving no room for further increases. Consequently, the Russian shortfall has to be compensated by increased LNG imports.

Second, the price impact on the gas market is most pronounced in the 40%DEF scenario. Given the dependence on Russian supplies and the high demand levels in Europe the shortfall cannot completely be compensated. In Bulgaria demand has to be curtailed leading to a price jump to the value of lost load (VOLL) which is arbitrarily assumed to be 10,000€/MWh. This also leads to price levels close to VOLL in Romania and Hungary. The price level in the remaining countries increases by ca. 5%. The high gas prices in Southeast Europe translate into equally distorted electricity prices. Only Spain, Portugal, Italy and Greece are decoupled enough from the remaining European electricity markets to be unaffected. Albeit, the price levels should be considered with

Table 4: Impact of Russian supply shock (2030)

	Changes in Gas Supply in 2030 [bcm per year]			Changes in Average Prices, Feb/Mar 2030 [€/MWh]		Changes in Gas Generation Feb/Mar 2030 [MW]	
	Russia	LNG	Africa	Gas	Electricity	Central/East Europe	South/West Europe
40%DEF	-15.51	+14.97	—	VOLL*	VOLL*	-592 (-7%)	+576 (+1%)
80%DEF	-8.05	+1.00	+6.51	+1.23 (3.55%)	+1.60 (2.05%)	-4708 (-25%)	+3568 (+9%)
80%GREEN	-8.28	+2.51	+5.50	+1.72 (4.99%)	+2.61 (3.81%)	-891 (-9%)	+868 (+3%)

Note: * The average price level is defined and distorted by the need for VOLL. For natural gas only Bulgaria, Hungary, and Romania are impacted. For electricity only Spain, Portugal, Italy and Greece are not significantly impacted.

care the results indicate that short term security of supply considerations need to play an important role in the *40%DEF* scenario.⁹

In both *80%* scenarios the shock leads to price increases but the system can handle the shortfall without demand curtailment. This is mainly an effect of the assumed lower gas demand in these scenarios freeing up pipeline capacities for transferring gas from Western to Eastern Europe. As a consequence, the price feedback to the electricity market is relatively modest. The spatial price impact are as expected: higher increases in Eastern Europe, lower impact in Western Europe. The impact is more pronounced in the *80%GREEN* scenario despite being the one with lower gas demand and more renewable generation. However, at the same time less conventional capacities are available lowering the flexibility in re-dispatching generation across Europe.

This can also be observed when examining the reallocation between Eastern and Western Europe. As we assume that direct gas and electricity demands are fixed in each country only the gas demand for electricity generation can be adjusted. As shown in Table 4, in all cases we observe a reduction in Central and East European countries and an increase in Southern and Western countries. In the *40%DEF* and *80%GREEN* cases the decrease and increase are about equal in absolute terms. However, in the *80%DEF* case we observe that about 1GW of electricity generation is reallocated from gas towards coal in Poland.

5.2 Conclusion on Short Term Interaction

The results of the short term sensitivity analysis shows how direct feedback effects of short term gas supply interruption can lead to distortions on the European electricity market. Especially the *40%DEF* results highlight that in case of insufficient security measures demand interruptions could happen. Nevertheless, the extend of shortages within our simulations is within a range that should be easily manageable by security related gas storage or flexible electricity demand options.

The results also show that a lower European gas demand, coupled with an extension of the existing pipelines to allow reverse flows, and a proper diversification of supply options helps to manage supply interruptions. Nevertheless, the feedback effects can still lead to larger locational deviations within the electricity system if either the generation capacity conditions are tight or limited transmission capacity prevents utilization of far off replacement capacities. Consequently, regional planning of electricity infrastructure should account for such situations.

6. CONCLUSIONS

The interdependence between natural gas and electricity markets is a major characteristic of current energy markets in all regions of the world. In this paper, we have applied a model that looks at natural gas and electricity simultaneously to analyze scenarios for European decarbonization at the horizon until 2050 to evaluate the underlying infrastructure implications of the transition paths. The analysis focuses on three interrelated topics in the electricity-gas nexus: the relation

9. The result that despite only Bulgaria, Hungary, and Romania having VOLL gas price levels nearly all electricity prices also jump to a VOLL equivalent indicates that in those periods the endogenous invested plants are the marginal generation technology. As we fix investments the model is restricted to reallocate the available capacities which are not sufficient to cover the fixed electricity demand. Test runs show that an additional 700MW of coal capacity would be constructed to compensate the shortage and reduce price increases on the electricity market to less than 5%.

between Europa and Russia and its impact on supply security; the interaction of different policy and market approaches; and the vertical relation between natural gas and electricity.

Regarding the first objective, the model analysis shows that development pathways with a clear policy focus on emission reduction, renewable energies and especially energy efficiency lead to a relaxation of the natural gas market conditions. This in turn reduces the dependency from Russian imports both in the long and short run. The more relaxed natural gas market constraints allow a more diversified import portfolio, reduce the impact of supply interruptions and make future large scale pipeline investment like Nordstream 2 superfluous. This also holds for less ambitious development pathways. The existing gas infrastructure coupled with expected extensions in LNG and storage provide a solid basis for diversified import alternatives. Consequently, the future development of global LNG trade and respective increases in LNG regasification capacities is likely to have a significant impact on both the gas market and price patterns across Europe as well as investment incentives for gas fired generation along western European countries.

Regarding the second objective on policy interrelation, the results highlight the strong dependency of investment decisions on the market framework. Especially as gas and coal are close substitutes for providing bulk electricity generation their cost level is crucial for investment decisions. The two main drivers are fuel and carbon prices. While one is influenced by European policy decisions the other is subject to global market dynamics. The influence has been highlighted by the *40%DEF* case. Despite a high carbon price in later periods coal was the preferred option as gas prices were increasing thereby reducing the cost disadvantage of coal. In addition, the two *80%* scenarios highlight the strong feedback effect of general energy policies aiming at demand reductions on the European gas market. The low demand levels allow an increase in gas fired electricity generation without jeopardizing supply security. Policy makers therefore should be aware of the different influences on market dynamics and adjust their policy design accordingly.

Finally, regarding the vertical interrelation between the different energy markets our model simulation shows that a more comprehensive evaluation provides benefits compared to singular market analyses. Similar to the policy interaction also the market interaction increases the complexity of decision making in energy related issues. Extending the existing development plans (i.e. the ENTSO-E and ENTSO-G TYNDPs) towards a joint energy development plan seems advisable. The European energy infrastructure projects of common interest are a first step in this direction.

In relation to the overarching research question on infrastructure implications of different carbon and renewable deployment pathways in Europe our coupled model analysis is in line with single sector model findings: albeit extensions of the existing network infrastructure are needed, their impact is not critical. The existing and projected capacity extensions in electricity and gas are sufficient for a wide range of potential market developments. Naturally, the supply infrastructure depends much more on the underlying policy framework and subsequent market developments. As indicated above, whether gas or coal fired power plants will provide the needed backup for renewables depends on climate, renewable and demand side policies. Consequently, a strong focus on policy design and market feedback should be a priority for decision makers.

Like all simulations, the presented results depend on the underlying scenario assumptions and model restrictions. Those can lead to an underestimation of the role of natural gas in the electricity market and thereby an underestimation of the interaction. Our model is time static and cannot capture aspects related to uncertainty and short term system stability. The six daily load segments as well as the monthly periods allow us to capture average demand and renewable intermittency aspects. Consequently, a share of the needed back-up costs is captured by our model. However, we are likely to underestimate the need for balancing and back-up for larger injection

variations. Those should lead to higher installed gas capacities (or alternative flexible plants). Nevertheless, the quantity effects on natural gas demand is likely to be smaller as those plants will not exhibit large running times.

The deterministic nature of the model also impacts the investment results. Given the security on price and quantity developments in the different scenarios the choice to invest into coal or gas is solely cost driven and small changes in those levels can switch the whole investment pattern. In reality the uncertainty about future developments can lead to a more diversified investment portfolio.

The regional clustering into national zones with respective cross-border exchange neglects local and regional network aspects. The DC-load flow approach allows us to capture the impact of unwanted loop flows but the aggregation falls short if inner country limits are constraining the exchange. Consequently, the model results represent a lower benchmark for congestion. Nevertheless, our results already show a high increase of congestion in the 80% scenarios. This development is likely to be more pronounced if a more detailed electricity network is included.

Regarding the resulting price levels, the assumption of perfect competition results in a potential downward bias and the obtained results represent a lower bound. Similar, the gas market model is Europe-centered and neglects interactions with the US and Asian natural gas markets. This can lead to a price underestimation (e.g. if LNG demand by Asia is strong) or an overestimation (e.g. if increasing shale gas from the US lowers global prices). A partial impact of such developments is captured in the sensitivity analysis. Nevertheless, a sharp decline of global gas prices due to LNG oversupply could easily alter the investment pattern in the 40%DEF scenario. This is highlighted by the investment pattern shown in Table 1. Given that coal and gas plant investment are partial substitutes changes in the underlying market price levels can easily shift the model results towards on or the other highlighting the importance of model evaluations to derive potential development paths.

Finally, the modeled price levels are only capturing those market dynamics included in the model formulation. This has three major impacts that need to be considered when aiming for policy conclusions based on the simulation. First, given that nuclear and renewable capacities are provided exogenously the electricity market price levels are likely to be insufficient for the underlying capacity extension in the 80% scenarios without additional out-of-market payments. Second, the exogenous carbon price excludes feedback effect of changed electricity emission levels on the ETS and thereby whether the envisioned 40/80% targets are kept without additional measures. Finally, the underlying policy frameworks defining the demand pathways in the three scenarios incur costs (e.g. for energy efficiency programs) which are not accounted for in the analysis. Consequently, while the market interaction results and the recommendations on careful and comprehensive policy design can be regarded as robust findings we cannot draw conclusions on which scenario framework is the optimal one from a total cost or social welfare perspective.

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APPENDIX

Table 5: Scenario assumptions.

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
<i>Yearly Electricity Demand [TWh]</i>										
40%DEF	2,904	2,963	3,156	3,292	3,476	3,567	3,737	3,926	4,099	4,237
80%DEF	2,902	2,978	3,232	3,292	3,377	3,407	3,612	3,828	3,850	3,793
80%GREEN	2,904	2,970	3,221	3,282	3,376	3,381	3,535	3,674	3,615	3,557
<i>Yearly Natural Gas Demand excluding electricity generation [TWh]</i>										
40%DEF	4,016	3,975	3,820	3,620	3,493	3,443	3,369	3,265	3,197	3,126
80%DEF	4,016	3,738	3,785	3,175	3,023	3,098	2,930	2,735	2,612	2,163
80%GREEN	4,016	3,743	3,791	3,193	3,033	3,094	2,844	2,552	2,377	1,916
<i>Total RES capacity (wind, solar, biomass, geothermal) [GW]</i>										
40%DEF	60.4	126.0	210.9	341.8	401.8	482.4	532.3	570.0	605.7	635.9
80%DEF	60.4	124.1	216.3	365.4	455.0	595.3	691.2	848.9	958.6	1056.7
80%GREEN	60.4	124.1	216.7	365.6	470.9	742.9	937.7	1246.7	1506.8	1753.0
<i>Total Nuclear capacity [GW]</i>										
40%DEF	136.5	130.3	130.0	126.2	116.3	125.5	132.5	136.7	147.9	154.5
80%DEF	136.5	134.7	129.0	126.8	107.3	104.5	104.7	107.8	112.6	100.2
80%GREEN	136.5	134.7	129.0	126.9	107.1	89.2	73.0	68.7	58.5	39.1
<i>Investment Costs [€/kW]</i>										
Coal	1,966	1,947	1,908	1,838	1,740	1,643	1,584	1,549	1,539	1,534
Gas	878	871	857	836	809	775	749	733	726	725
<i>Coal price [€/MWh]</i>										
40%DEF	6.9	7.6	10.4	13.4	15.5	15.9	16.3	16.5	16.9	17.7
80%DEF	8.2	10.0	11.7	12.8	14.7	14.3	13.9	13.2	12.7	12.4
80%GREEN	8.2	10.0	11.7	12.8	14.7	14.3	13.9	13.2	12.7	12.4
<i>Gas price [€/MWh]</i>										
40%DEF	19.5	19.5	23.6	32.3	39.6	41.5	45.2	48.9	52.8	57.6
80%DEF	19.5	23.6	23.6	32.3	35.7	33.2	33.9	31.8	29.0	28.8
80%GREEN	19.5	23.6	23.6	32.3	35.7	33.2	33.9	31.8	29.0	28.8
<i>CO₂ price [€/t]</i>										
40%DEF	0.0	11.4	13.9	16.8	20.4	36.7	51.0	52.5	51.5	51.0
80%DEF	0.0	11.4	12.9	25.5	35.7	53.0	71.3	96.8	158.0	270.1
80%GREEN	0.0	11.4	12.9	25.5	30.6	35.7	63.2	93.8	152.9	290.4