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Investments in a Combined Energy Network Model: Substitution between Natural Gas and Electricity?

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Natural gas plays an important role in the future development of electricity markets, as it is the least emission-intensive fossil generation option and additionally provides the needed plant operating flexibility to deal with intermittent renewable generation. As both the electricity and the natural gas market rely on networks, congestion in one market may lead to changes in the other. In addition, investment in one market impacts investment in the other market to the extent that these investments may even become substitutes for each another. The objective of this paper is to develop a dynamic model representation of coupled natural gas and electricity network markets to test the potential interaction with respect to investments. The model is tested under simplified conditions as well as for a stylized European network setting. The results indicate that there is sufficient potential for investment substitution and market interactions that warrant the application of coupled models, especially with regard to simulations of long-term system developments.

Keywords: Electricity network, Natural gas network, Europe, MCP
JEL-Codes: L94, L95, C63

1. Introduction

Energy systems throughout the world are expected to undergo a transition in the coming decades. Industrialized countries aim to switch increasingly from fossil-based to renewable energy-fueled systems, and it is forecast that a significant increase in energy demand will occur in developing regions. Both developments will require a large amount of investment in energy production and transport infrastructure; e.g., IEA (2011a) estimates

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global investment needs of approximately 38 trillion USD up until 2035. As energy markets are interlinked due to their substitutability for specific utilizations (e.g., heating oil or gas vs. biomass or electricity) and the direct usage of energy fuels in downstream markets (e.g., coal, oil and gas as fuel input for electricity) the relations between markets need to be taken into account in estimates of future developments. In addition energy markets often rely on network structures which add a spatial layer to the problem.

The interaction of energy markets is particularly relevant for natural gas and electricity systems. The increasing importance of emission reductions raises the need for a shift from coal-based to natural gas-fired units. Similarly, the increased utilization of intermittent renewable generation units increases the need for more flexible generation units as back-up capacities which are mainly assumed to be gas-fired. These developments are likely to increase demand for natural gas in the electricity sector, which can increase the need for investment in gas infrastructure. On the gas supply side the 'fracking boom' in the United States, the general global prospects for unconventional gas, and the further increases in the LNG infrastructure are likely to lead to shifts in the global natural gas market dynamics and consequently gas prices (IEA, 2011b). Furthermore, the conflict between Russia and the Ukraine has awakened security of supply concerns in Europe's energy markets. These changes in the natural gas market feed back into the electricity market and impact the prospects of gas as fuel option.

Given these medium- and long-term challenges, this article presents a combined natural gas and electricity market model framework which focuses on investment options while accounting for the network characteristics of both markets. The model follows existing single market representations of natural gas and electricity networks and is formulated as equilibrium approach. Using the model, we highlight the interaction of natural gas and electricity investment alternatives, first, using an illustrative network setup and, second, using a stylized European network.

Focusing on the above-described linkage between gas and electricity markets via the fuel option in power generation, the interaction can be traced to three main elements: gas production costs, pipeline topology, and the topology of the electricity transmission network. The first aspect of gas production costs basically summarizes the competition with other fuels such as coal or nuclear generation. Based on overall market conditions, this impacts relative prices in electricity generation and thereby determines the potential revenues for gas-fired power generation. This occurred in 2012, for example, when the price spread between gas and coal in the U.S. market led to a shift from coal- to gas-fired generation.[1] The second aspect of pipeline topology captures the impact of costly and potentially limited transport alternatives within the gas market. Even though the overall price level may make gas a competitive electricity generation option, this may not hold for all locations within the market, as some locations are more costly to supply due to transport cost depending on the pipeline network structure. Examples for the impact of pipeline constraints are price divergences between the different natural gas trading hubs in Europe which in a competitive market represent the difference in transport cost. This aspect also includes the potential need to construct the necessary pipelines to supply

[1] http://www.eia.gov/todayinenergy/detail.cfm?id=11391

specific locations.

The third aspect of electricity network topology captures the influence of the structure of the electricity transmission grid on local prices. Electricity transmission fundamentally differs from pipeline transmission: While the system operator can decide about the flows along a pipeline network, in an electricity network flows are determined by physical laws and the sole choice of the system operator is the injection and withdrawal at the different nodes in the system. Put differently, a change in the topology of the transmission system or a change in the supply and demand patterns at a given node leads to a change of the network flows along all lines in the system. This behavior of electricity flows is known as the *loop flow* problem. Albeit, at its core this is a technical issue it has important implications for market and policy related decissions.

Seen from a financial perspective, the decision on how to supply local electricity demand is impacted by the fuel price differences, potential network limitations on the supply and electricity side, and the current market conditions in the electricity market. Naturally, to derive consistent evaluations about economically efficient developments in the electricity market, it is necessary to include the supply-market side as well as the network characteristics in the analysis.

Over the last two decades, research has focused on the analysis of both electricity (e.g, Leuthold et al, 2012; Moest and Keles, 2010) and natural gas markets (e.g., Lise and F., 2009; Egging et al, 2010), as well as on modeling the overall energy system (see, e.g., Pfenninger et al, 2014, for a review). Within this strand of research, the coupling of electricity and natural gas markets has gained increasing attention in recent years, and has predominantly focused on the incorporation of natural gas constraints in the short-run electricity market dispatch via different modeling approaches (see, e.g., Rubio et al, 2008; Liu et al, 2009; Damavandi et al, 2011; Erdener et al, 2014). Most of these approaches focus on the technical interaction of both markets. Medium- to long-term analyses with endogenous investment representations are rather limited so far. Unsihuay-Vila et al (2010) develop a coupled optimal investment model for natural gas and electricity networks which excludes loop-flow aspects and apply it to the Brazilian network. Lienert and Lochner (2012) combine an electricity model (DIME) and a natural gas model (TIGER) with a stylized transmission approach based on cross-border transmission restrictions and apply it to the European markets, and provide long-term assessments on gas-fired generation capacities. Bakken et al (2007) develop a coupled model design for multiple energy infrastructures. However, the investments are externally defined and ranked by the model approach, but no endogenous optimal investment is obtained. Geidl and Andersson (2006) use a hub-based approach for structural optimization regarding the conversion technologies in the hubs (i.e., plant technologies), but not for the network connecting the hubs. Finally, Chaudry et al (2014) develop a combined network extension model for natural gas and electricity with detailed network flow representations. Although, the physics of power flows are explicitly included in the model formulation, it is not indicated whether their model accounts for feedback effects due to investment in network capacity. The application to the U.K. system relies on a linear setup of the British electricity transmission system and therefore does not account for the externalities stemming from electricity transmission.

The present article extends this discussion on the interaction of natural gas and electricity markets by including investment decisions in a combined natural gas and electricity model. In Section 2, we first provide the underlying mathematical formulation based on the static model of Abrell and Weigt (2012). The natural gas market is represented including gas producers, traders, consumers, and the pipeline operator. Similarly, the electricity market model includes generators, consumers, and the system operator. We allow for investments in natural gas and electricity transmission infrastructure, as well as in electricity generation capacity. The models are then coupled via the market clearing condition for natural gas: On the one hand, demand for natural gas as a fuel input of power generation becomes endogenous in the market clearing for natural gas. On the other, the natural gas price is included as a endogenous price variable in the generators' profit optimization.

In Section 3, the model framework is applied to a stylized four node network. The stylized network provides insights on the ability of the developed model to capture the substitution effect between investments and visualizes the impact of loop flows on market results. We first provide a simple linear network setup ranging from production which is distantly located from demand but cheap in terms of production costs to production facilities which are closely located to demand, but which exhibit high production costs. As demand coverage at a network location includes both the pure production costs and the transport costs, a tradeoff between both elements will be reached based on the underlying cost structures. The same principal also holds when the linear structure is omitted, and a meshed structure is used thereby introducing the loop flow problem. Due to the nature of the power flows, the resulting investment pattern exhibits non-trivial deviations from the linear setup. Nevertheless, both cases provide the basic investment pattern, that with higher shares of transport investment costs, additional production options which are closer to demand are realized including natural gas extension alternatives.

In Section 4, we apply the model in a stylized European market framework. Each European country is represented by one node in the natural gas and electricity transmission system. These nodes are connected by cross-border pipelines and electricity lines with aggregated capacities. The model is calibrated in order to reproduce the natural gas and electricity market for the year 2012. We introduce exogenous carbon prices and increase the share of renewable electricity generation. By varying the electricity network extension costs, the resulting optimal power plant and pipeline investments differ significantly. In case of cheap transmission extension costs, gas-fired plants are situated at locations with low gas prices, and the electricity network is used as an energy carrier. In case of high transmission extension costs, it becomes optimal to reduce electricity transmission expansion. In this case, the natural gas pipeline system is expanded and gas-fired power plants are build in closer distance to demand locations. Given the high degree of uncertainty regarding gas supply in Europe, as well as the future development of the electricity market, and the required construction time and cost of overhead electricity transmission lines, the results of this study highlight the importance of both establishing a European wide energy infrastructure planning and an integrated evaluation of gas and electricity. This paper's results are in line with the ongoing energy infrastructure planning and regulation progress undertaken by the European Commission, namely the

proposed regulation regarding guidelines for trans-European energy infrastructure and related projects of common interest. However, specific issues regarding these regulations still need to be addressed, such as the coordination of regulated network investments and competitive production, generation, and storage investments.

Summarizing, our contribution to the existing literature on combined natural gas and electricity market modeling is threefold: Firstly, the model couples the short-term dimension of market operation with the long-term aspects of investment decisions within a closed market framework. Secondly, the formulation as an equilibrium problem in a mixed complementarity format extends the existing optimization approaches of techno-economic models or energy system approaches. Thirdly, the model includes an integrated electricity transmission extension representation that accounts for the physics of power flows and avoids more complicated formulations such as iterative approaches based on the recalculation of network flow characteristics[2] after investments have taken place.

Overall, the model proves to be suitable to analyze the interaction of natural gas and electricity markets. The application to a European market representation provides first insights into the relevance of the interaction for upcoming investment decisions. The results highlight the importance of a more holistic view on energy infrastructure decisions, particularly due to the increased importance of flexible gas plants for electricity markets and the aspects of supply security for the European natural gas market.

2. Numerical Framework

The combined model representation follows the design of single market models and couples the natural gas and electricity segments via a fuel market in which natural gas can be utilized as the fuel input for power generators. The overall model setup, market participants, and traded commodities are presented in Figure 1. While the markets differ in their network representation, the remaining market structure is similar. We assume profit maximizing companies on the production site and represent the demand side via a demand function. In the natural gas market, a trader buys natural gas from the producers and sells to both electricity generators and natural gas end-consumers. In order to transport the gas from supply to demand locations, the trader furthermore buys transport services from a pipeline operator who manages the pipeline network. In the electricity market, the transmission system operator basically takes up the role of the trader in bridging supply and demand while accounting for the physics of power flows.

We restrict both market representations to the necessary minimum to capture the investment interaction effect. Naturally, the gas market could be extended by including both LNG and storage operators that act as traders, once spatial on a separate network structure (LNG routes) and once temporal.[3] Similarly, in the electricity market one can include pump storage operators. These additional market participants can be included

[2] I.e., the flow characteristics of electricity networks can be represented by using power transfer distribution factors (PTDFs) which determine the flow on all lines in a system induced by the injection of electricity at an certain node.

[3] In our quantitative analysis of the European market LNG is included in a stylized manner representing regasification capacities as pipelines to the perspective countries.

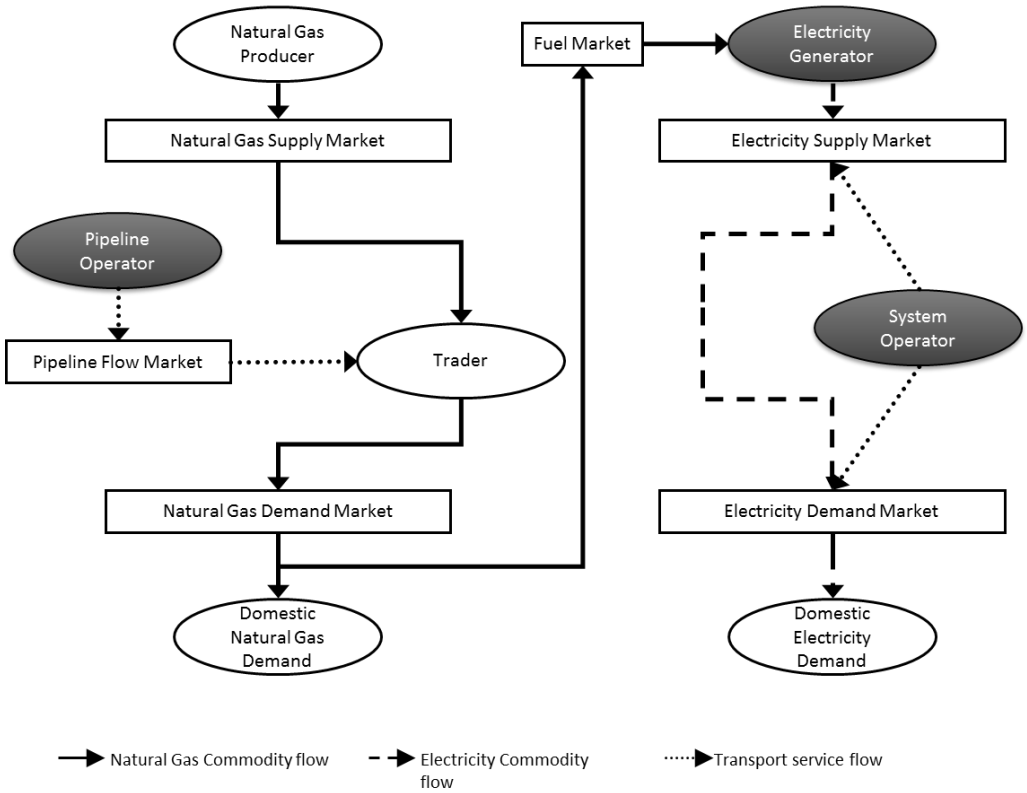

Figure 1: Model Overview

following the same logic as for the existing actors. Furthermore, for clarity we restrict the representation of investments to the pipeline operator, electricity generators, and the electricity transmission network operator (highlighted in Figure 1). However, the same investment representation can be used for other market participants as well.

The dynamic model setting is formulated as Mixed Complementarity Problems (MCP) and is based on Abrell and Weigt (2012). We provide the optimization setting for each market participant in the natural gas (Section 2.1) and electricity (Section 2.2) market as well as the market clearing conditions equalizing demand and supply which serve to link the tow markets (Section 2.3).[4] We assume perfect competition, i.e., all market participants take prices as given. However, the equilibrium concept allows an easy adjustment of the underlying competition assumptions. The MCP model is formulated in the General Algebraic Modeling System (Brooke et al, 2008) and solved using the PATH solver (Ferris and Munson, 2000).

[4]The MCP version of the model is provided in Appendix A and the notation is listed in Annex D.

2.1. Natural Gas Market

In the natural gas market, we explicitly model four market participants: producers, traders, the pipeline operator, and final consumers. Natural gas producers extract the gas and sell it to the trader. Only the trader serves final demand by buying natural gas and the pipeline transport services necessary to transport it to the final consumers. Consequently, three markets in the natural gas market are explicitly modeled: the supply market, the pipeline transport service market, and the final demand market.

The gas network is described by nodes $g \in \mathcal{G}$ and pipelines given as directed and ordered pairs $(g, \tilde{g}) \in \mathcal{G} \times \mathcal{G}$ with capacity $cap^{pipe}_{g\tilde{g}}$. Time periods in the natural gas model are denoted by $t \in \mathcal{T}^{gas}$. We assume that natural gas demand in period t at node g, DEM^{gas}_{gt} is a linear function of the demand price PD^{gas}_{gt} at that node:

$$DEM^{gas}_{gt} = a^{gas}_{gt} + b^{gas}_{gt} PD^{gas}_{gt} \quad \forall g \in \mathcal{G}, t \in \mathcal{T}^{gas} \tag{1}$$

The natural gas producer at node g maximizes its profit by selling the amount of gas extracted, X^{gas}_{gt}, under the given capacity cap^{gas}_{gt}. It receives the node-dependent natural gas supply price PS^{gas}_{gt} and produces under constant marginal cost c^{gas}_{gt}:

$$\max \sum_{t} \left(PS^{gas}_{gt} - c^{gas}_{gt} \right) X^{gas}_{gt} \tag{2}$$

$$\text{s.t.} \quad cap^{gas}_{gt} \geq X^{gas}_{gt} \quad (PC^{gas}_{gt}) \tag{3}$$

$$X^{gas}_{gt} \geq 0$$

The shadow price on the capacity constraint PC^{gas}_{gt} is provided in parenthesis.

The pipeline trader buys gas at the node of origin $\hat{g}$ at the supply price $PS^{gas}_{\hat{g}t}$ and sells it at the destination node $\tilde{g}$ to final consumers at the final demand price $PD^{gas}_{\tilde{g}t}$. As the gas needs to be transported from $\hat{g}$ to node $\tilde{g}$, the operator needs to decide about the flow on the different pipelines from node g to $\tilde{g}$, $F^{gas}_{g\tilde{g}t}$, and the respective transport services have to be rented at price $PT^{pipe}_{g\tilde{g}t}$. Thus, the maximization problem of the pipeline trade is given as:

$$\max \sum_{\hat{g}gt} \left(PD^{gas}_{gt} - PS^{gas}_{\hat{g}t} \right) T_{\hat{g}gt} - \sum_{g\tilde{g}t} PT^{pipe}_{g\tilde{g}t} F^{gas}_{g\tilde{g}t} \tag{4}$$

$$\text{s.t.} \quad \sum_{\tilde{g}} F^{gas}_{\tilde{g}gt} + \sum_{\tilde{g}} T_{g\tilde{g}t} = \sum_{\tilde{g}} F^{gas}_{g\tilde{g}t} + \sum_{\tilde{g}} T_{\tilde{g}gt} \quad (PN^{gas}_{gt}) \quad \forall g \in \mathcal{G} \tag{5}$$

$$T_{\hat{g}gt}, F^{gas}_{\tilde{g}gt} \geq 0$$

Equation (5) is the flow conservation constraint for pipeline flows which states that at each node incoming and outgoing flows have to be balanced. Economically it is interpreted as the market clearing condition at the node level and the associated dual variable PN^{gas}_{gt} can be interpreted as the price of an additional unit of natural gas at

that node.[5]

The pipeline operator organizes flows $F^{pipe}_{g\tilde{g}t}$ on a particular pipeline from node g to node $\tilde{g}$ which cause cost $c^{pipe}_{g\tilde{g}t}$. Besides operating the pipelines, the operator also needs to decide on the pipeline capacity investment $I^{pipe}_{g\tilde{g}t}$ given the initial pipeline capacity $\overline{cap^{pipe}_{g\tilde{g}}}$. Given the annual cost of pipeline capacity $ci^{pipe}_{g\tilde{g}t}$, the maximization problem of the pipeline operator becomes:

$$\max \sum_{g\tilde{g}t} \left[\left(PT^{pipe}_{g\tilde{g}t} - c^{pipe}_{g\tilde{g}t} \right) F^{pipe}_{g\tilde{g}t} - ci^{pipe}_{g\tilde{g}t} I^{pipe}_{g\tilde{g}t} \right] \tag{6}$$

$$I^{pipe}_{g\tilde{g}t} + \overline{cap^{pipe}_{g\tilde{g}}} \geq F^{pipe}_{g\tilde{g}t} \quad (PC^{pipe}_{g\tilde{g}t}) \qquad \forall g, \tilde{g} \in \mathcal{G}, t \in \mathcal{T}^{gas} \tag{7}$$

$$F^{pipe}_{g\tilde{g}t}, I^{pipe}_{g\tilde{g}t} \geq 0$$

2.2. Electricity Market

In the electricity market model, we have three market participants: generators, the transmission system operator, and final consumers. The transmission system operator is the sole trader in the market, buying electricity from generators at their respective nodes and selling to consumers while accounting for constraints imposed by the transmission network and, in particular, for the special characteristics of electricity flows, i.e., loop flows.

Time periods in the electricity model are denoted by $t \in \mathcal{T}^{ele}$. Each time period is subdivided into load segments $k \in \mathcal{K} := \{k_0, k_1, \cdots, k_K\}$. Nodes in the electricity network are given as $e \in \mathcal{E}$, and lines are denoted by $l \in \mathcal{L} \subseteq \mathcal{E} \times \mathcal{E}$.

Final demand is assumed to be linear for all time periods t and load segments k:

$$DEM^{ele}_{ekt} = a^{ele}_{ekt} + b^{ele}_{ekt} P^{ele}_{ekt} \quad \forall e \in \mathcal{E}, k \in \mathcal{K}, t \in \mathcal{T}^{ele} \tag{8}$$

Power plant technology $i \in \mathcal{I}$ is characterized by the heat efficiency η_{if}, where $f \in \mathcal{F}$ denotes the set of fuels. The heat efficiency is assumed to be zero if technology i cannot produce with fuel f. Fuel f is also characterized by the carbon content θ_f, the carbon price pe_{ekt}, and the fuel price pf_{fekt}. Given the initial installed capacity $\overline{cap^{ele}_{ie}}$, the generator has to decide about the amount of output X_{iekt} and investment in the installed

[5] From a technical point of view it is required that the mass of natural gas balances at a node. Thus, the equation holds with equality imply that the usual free disposal assumption does not hold which eventually leads to negative prices.

capacity I_{iet}^{ele} at cost ci_{iet}^{ele}:

$$\max \sum_{i,e,k,t} \left(P_{ekt}^{ele} - \sum_{f \text{ if } \eta_{if}>0} \frac{pf_{fekt} + \theta_f pe_{ekt}}{\eta_{if}} \right) X_{iekt} - \sum_{i,e,t} ci_{iet}^{ele} I_{iet}^{ele} \tag{9}$$

$$\text{s.t. } I_{iet}^{ele} + \overline{cap_{ie}^{ele}} \geq X_{iekt} \quad \forall i \in \mathcal{I}, e \in \mathcal{E}, k \in \mathcal{K}, t \in \mathcal{T}^{ele} \quad (PC_i^{ele}) \tag{10}$$

$$X_{iekt}, I_{ie}^{ele} \geq 0$$

In contrast to natural gas flows on pipelines which can be seen as directly controllable, flows on an electricity transmission grid depend on the injection at the different nodes and the characteristics of the network. In particular, flows on the network are determined by the thermal capacity of single lines. Thus, investing in transmission line capacity alters the calculation of the power flows along the network. The physical properties of the electricity network are described by the arc node incidence matrix i_{le}, the line reactance x_l, and the initial line capacity given as $\overline{cap_{lt}^{line}}$. The network operator decides on net-injection into the grid at node e, Y_{ekt}^{ele}, and the investment in line capacity I_{lt}^{line}, given the electricity price and the investment cost ci_{lt}^{line}. Given the decisions, the voltage angle difference Δ_e and the flow on line l, F_{lkt}^{ele} are determined by physical laws:[6]

$$\max \sum_{e,k,t} P_{ekt}^{ele} Y_{ekt}^{ele} - \sum_{l,t} ci_{lt}^{line} I_{lt}^{line} \tag{11}$$

$$\text{s.t.} \quad I_{lt}^{line} + \overline{cap_{lt}^{line}} \geq |F_{lkt}^{ele}| \quad \forall l \in \mathcal{L}, k \in \mathcal{K}, t \in \mathcal{T} \tag{12}$$

$$\frac{I_{lt}^{line} + \overline{cap_{lt}^{line}}}{\overline{cap_{lt}^{line}}} \frac{1}{x_l} \sum_e i_{le} \Delta_e = F_{lkt}^{ele} \quad (\lambda_{lkt}^F) \quad \forall l \in \mathcal{L}, k \in \mathcal{K}, t \in \mathcal{T} \tag{13}$$

$$Y_{ekt}^{ele} = \sum_l i_{le} F_{lkt}^{ele} \quad (\lambda_{ekt}^Y) \quad \forall e \in \mathcal{E}, k \in \mathcal{K}, t \in \mathcal{T} \tag{14}$$

$$F_{lkt}^{ele}, I_{lt}^{line} \geq 0$$

$$Y_{ekt}^{ele}, \Delta_e \text{ free}$$

Equation (14) implicitly defines the flow on a line based on the net injection at nodes e, while equation (13) determines the linkage between capacity investments and power flows. Equation (12) restricts the flow on electricity line l by the installed transmission capacity. As transmission lines are modeled as undirected arcs, the equation holds for either direction and the corresponding multipliers are denoted as PC_{lkt}^{Line+} and PC_{lkt}^{Line-}.

[6] A more detailed explanation of the line flows and its dependency on the amount invested in the grid is given in Appendix B

2.3. Market Clearing Conditions

The market clearing condition for electricity equilibrates net-injection into the electricity grid to electricity generation net of final demand and storage. Using the perpendicular sign ($\perp$) to denote complementarity of market clearing conditions and the respective prices, the electricity market clearing condition becomes:

$$X_{ekt} = DEM^{ele}_{ekt} + Y_{ekt} \quad \perp \quad P^{ele}_{ekt} \text{ free} \quad \forall e \in \mathcal{E}, k \in \mathcal{K}, t \in \mathcal{T}^{ele} \tag{15}$$

On the natural gas supply market, gas extractors sell gas to natural gas traders:

$$X^{gas}_{gt} \geq \sum_{\tilde{g}} T_{g\tilde{g}t} \quad \perp \quad PS^{gas}_{gt} \geq 0 \quad \forall g \in \mathcal{G}, t \in \mathcal{T}^{gas} \tag{16}$$

Natural gas trades necessitate buying pipeline transport services offered by pipeline operators:

$$F^{pipe}_{pt} \geq \sum_{\hat{g}} F^{gas}_{\hat{g}pt} \quad \perp \quad PT^{pipe}_{pt} \geq 0 \quad \forall p \in \mathcal{P}, t \in \mathcal{T}^{gas} \tag{17}$$

The two energy markets, natural gas and electricity, are coupled using the market clearing equation for natural gas final demand. In order to establish this link, we need to establish a mapping from electricity to natural gas network nodes. We assume, that each electricity node can be served by only one natural gas node, but that a natural gas node can serve multiple electricity nodes. This mapping is denoted by $\mathcal{M}^N_{eg} \subset \mathcal{E} \times \mathcal{G}$.

Besides the locational mapping, we also need to establish a temporal matching, as the market may operate along different time scales. We assume, that natural gas prices are constant within a period of the electricity model; i.e., the gas price does not vary across load segments. Furthermore, it is assumed that each electricity period belongs to exactly one natural gas model period. However, one natural gas model period may serve several electricity periods. We denote this mapping by $\mathcal{M}^T_{t^{ele}t^{gas}} \subset \mathcal{T}^{ele} \times \mathcal{T}^{gas}$. Given these mappings, the natural gas market clearing equation becomes:

$$\sum_{\hat{g}} T_{\hat{g}gt^{gas}} \geq DEM^{gas}_{gt^{gas}} + \sum_{\substack{e \in \mathcal{M}^N_{eg} \\ k, t^{ele} \in M^T_{t^{ele}t^{gas}} \\ i \text{ if } \eta_{i'gas'} > 0}} \frac{X_{iekt^{ele}}}{\eta_{i'gas'}} \quad \perp \quad PD^{gas}_{gt^{gas}} \geq 0 \quad \forall g \in \mathcal{G}, t \in \mathcal{T}^{gas} \tag{18}$$

On the left-hand side of equation (18), the supply at node g is given as the sum of all source nodes $\hat{g}$ delivering to that node. On the right-hand side, total demand is given as the sum of final and electricity demand. Electricity demand is derived by using the mapping between the network nodes, summing out the electricity time periods, and identifying gas-demanding technologies by a positive heat efficiency for natural gas.

2.4. Model Assumptions and Limitations

The numerical framework presented necessarily involves simplifying assumption in order to keep the model tractable and to focus on the basic substitutability between different types of investments. We now discuss the main assumptions taken and their impact on the results of the simulations.

We assumed natural gas to be a homogeneous commodity which should be interpreted in way that the extraction cost at each node already include the cost of mixing the extracted gas to a certain pre-defined quality required to be allowed to feed into the pipeline grid. This assumption allows simplifying the expressions of the pipeline flows which otherwise would require using a multi-commodity flow problem (see e.g. Abrell and Weigt, 2012). Demand and cost functions are assumed to be linear. While this is an obvious simplification[7], it should be seen in the light of the model usage: we calibrate the model to a benchmark point and evaluate changes in parameters against this reference case. Thus, the linearity assumption can be considered as first-oder linearizion around the reference point. Such an approximation behaves well if changes from the reference point are not too large. In case of large deviations the results are biased as higher order terms are neglected.

For the case of demand, we imposed independence of the demand functions, i.e., the cross-price elasticity between natural gas and electricity is assumed to be zero. Considering gas and electricity as substitutes in final consumption, the cross-price elasticity would be negative. In turn, a decrease (increase) in the electricity (natural gas) price would lead to an increase (decrease) of natural gas (electricity) demand which leads to an increase (decrease) of the investment incentives. Thus, neglecting the substitutability of electricity and natural gas in final consumption slightly underestimates the investment incentives in cases when parameter changes induce a price to rise.

For simplifications, losses in the transmission grids have not been explicitly modeled, i.e., are implicitly assumed to be part of the transportation cost. We assumed that each electricity node can only be served by one natural gas node, but that a natural gas node can serve multiple electricity nodes. This assumption is interpreted as implementing different natural gas pricing zones each represented by a single node. Within a pricing zone the natural gas price is uniform. Relaxing the assumption requires the introduction of additional variables representing natural gas purchases of electricity producer e from node g which replace natural gas demand in the market clearing equation (18), i.e., the term within the summation of the right hand side. Additionally, the generators optimization problem (equations 9, 10) needs to be altered to include the choice between different natural gas nodes. As long as natural gas deliveries from different nodes are interpreted as perfect substitutes in electricity production, the prices at nodes which deliver to the same electricity generator have to equalize (or the generator does not buy from the node). Thus, this assumption has no influence on the results as long as the transport cost between the natural gas nodes are sufficiently large, i.e., the nodes form a separated price zone.

[7] E.g., the transformation coefficient in electricity generation, the heat efficiency, is usually not constant along the production cycle. Also, natural gas extract cost are rather unlikely to be linear.

The power flow calculation is based on the DC-Load-Flow approach (e.g, see Leuthold et al, 2012) capturing the basic nature of meshed electricity networks but neglecting further AC related aspects like reactive power. As losses are not accounted resulting price differences between electricity nodes are solely based on congestion.

3. A Four-Node Test Case

In this section, we illustrate the substitution of generation capacity and transmission infrastructure investments by means of two simple four-node networks which ignore final demand for natural gas. We first present a linear network configuration followed by a more complicated case with a meshed electricity network.

Starting with the simple linear network which excludes the effect of loop flows in the electricity network, we can highlight the substitution of investment alternatives based on gas prices and pipeline topology. The electricity network consists of four nodes connected by three lines (Figure 2, left panel). Electricity demand is located at the rightmost node, and generation facilities are located at the remaining nodes. Initially, there is no generation facility at the final demand node. However, it is possible to invest in generation capacity at that node. The marginal generation costs are decreasing in the distance to demand; i.e., the leftmost node exhibits the lowest marginal generation cost. Natural gas is supplied at three nodes connected by two pipelines without a capacity limitation. Each of the natural gas nodes is associated with one of the electricity generation nodes. Initially, no pipeline to the final demand node exits, but it is possible to connect to that node. Natural gas extraction takes place at the leftmost node. The marginal natural gas extraction costs are constant. However, pipeline transport is costly, and causes the price of natural gas to increase in line with the distance from extraction (i.e., from left to right). This basic structure depicts the common setting in energy markets, where fossil fuel supply locations and electricity demand centers are quite distant from each other. Therefore, power generation can either take place close to the fuel supply, thereby utilizing cheap fuel costs but high transmission costs, or closer to the demand centers, thereby requiring higher fuel transport costs and respective increases in generation costs, but lower transmission expansion investments.

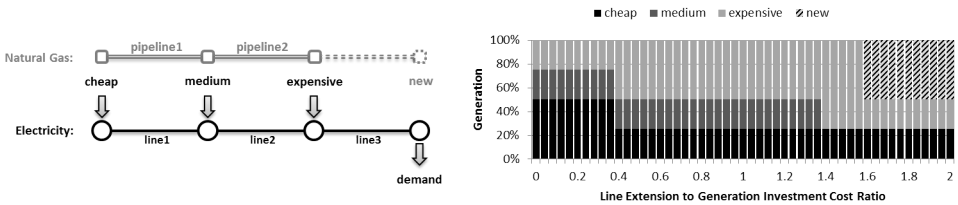

Figure 2: Linear Test Case

We assume an initial capacity endowment for all existing infrastructure elements that is sufficient to cover the initial demand level with a mix of production from the cheap

and the expensive plant.[8] In the following, we increase electricity demand, which consequently necessitates investments in generation and transport capacity. Given this simple setting, it is obvious that the cheap generation option requires the highest amount of network investment to satisfy the increased demand. Depending on the underlying cost levels, the cheap generator will be the primary investment option as long as network extension costs are lower than the cost disadvantage of the next costly generator. Similarly, the option to invest in extending the gas network and constructing a generator directly at the demand node will be chosen if the costs of pipeline extension and subsequent pipeline transport costs are lower than extending the last electricity line.

In the right-hand panel of Figure 2, we increase the electricity transmission investment costs, holding all other parameters constant, and plot this against the electricity generation by node. For low transmission extension costs, electricity transmission expansion is cheap and, thus, it is optimal to invest in the cheap power plant and extend the network accordingly. With increasing transmission extension costs, the level of transmission investments decreases. First, the medium-priced plant is still a valid supply option, as it requires less network extension beyond the initial capacities than the cheap unit. However, with further increasing extension costs, the investment pattern switches completely to the expensive generator. Finally, if electricity transmission costs increase further, it becomes optimal to invest in a new pipeline connection to the final demand node, installing new generation capacity at that node, and to refuse to invest in electricity transmission infrastructure.

The linear setup could be interpreted as a representation of a model formulation that treats electricity as a directed and controllable flow that accounts for transmission limitations, but not for power flow characteristics. One advantage of the proposed model formulation is its capability to deal with the physics of power flows. Therefore, the second test case extends the linear setup by introducing a meshed electricity network topology (Figure 3, left-hand panel).

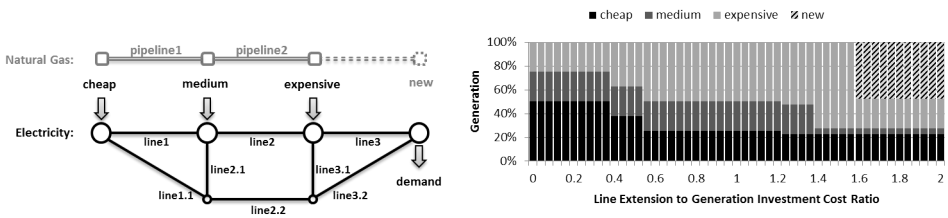

Figure 3: Meshed Test Case

In this test case, we extend the network with two auxiliary nodes vis-à-vis the medium-priced and the expensive generation nodes and additional lines connecting the new nodes with the existing ones. The transmission capability is adjusted to allow the same initial transmission as in the linear case. The remainder of the system is kept identical.

[8]The numerical specification of the test cases is given in Appendix C.

We perform the same extension analysis by varying only transmission investment costs. Although, the meshed network is highly similar to the linear case, the resulting extension pattern differs slightly (Figure 3, right-hand panel). Firstly, there are two additional extension phases, and secondly, the final natural gas extension is slightly lower, as more generation from the medium-priced generator is utilized compared to the linear setting. This is a result of the loop flow property of electricity transmission networks: Changing the underlying parameters of a single line in a meshed network via investments alters the power flow distribution throughout the whole network. Given this, extension on an individual line may allow additional transmission over other lines in the network. To capture this effect, it is necessary to include a physical power flow representation and account for the changes induced by investments on the flow distribution as in the proposed model framework.

Naturally, the differences between the linear and the meshed test cases are based on the chosen network topology and the underlying cost and line parameter, and cannot be generalized. Nevertheless, the example shows, that due to the physical characteristics of electricity transmission, the resulting extension pattern can easily deviate from a simplified linear representation, even for highly simplistic network setups.

In summary, the numerical test cases provide us with three basic insights. First, the developed model is, in principle, capable of simulating combined electricity and natural gas market settings and provides results that are in line with expected outcomes. Second, the substitution effect between gas and electricity remains valid for both simplified linear settings and meshed networks, although the actual extension strongly depends on the underlying cost parameters. And third, the nature of meshed networks makes clear predictions of optimal investments more complicated and requires the need for subsequent modeling with power flow elements. A simplified linear treatment neglecting loop flow externalities is likely to lead to inaccurate estimates.

4. European Market Evaluation

We will now turn our attention to an analysis of the European electricity and natural gas markets using a stylized numerical model to evaluate the potential impact of the substitution effect under real-world market conditions. The simple four-node example has shown that for specific investment cost relations we observe a substation between electricity and natural gas transit, especially in case of long distance transit. At the same time the meshed structure of electricity networks makes it hard to predict the actual investment pattern. Given that a large share of European gas demand is satisfied by imports via long distance pipelines and electricity trade is still subject to congestion on cross-border links, we have a setup that could make the substitution effect relevant in case of future investment decisions.

The analysis is focused on continental Central Europe (Figure 4). We evaluate the impact of investment cost ratios between gas and electricity on a future European market scenario with a significant increased need for natural gas in the electricity market (i.e., induced by high emission prices). In the following, we first present the underlying dataset

and scenario design, and then discuss the obtained results.

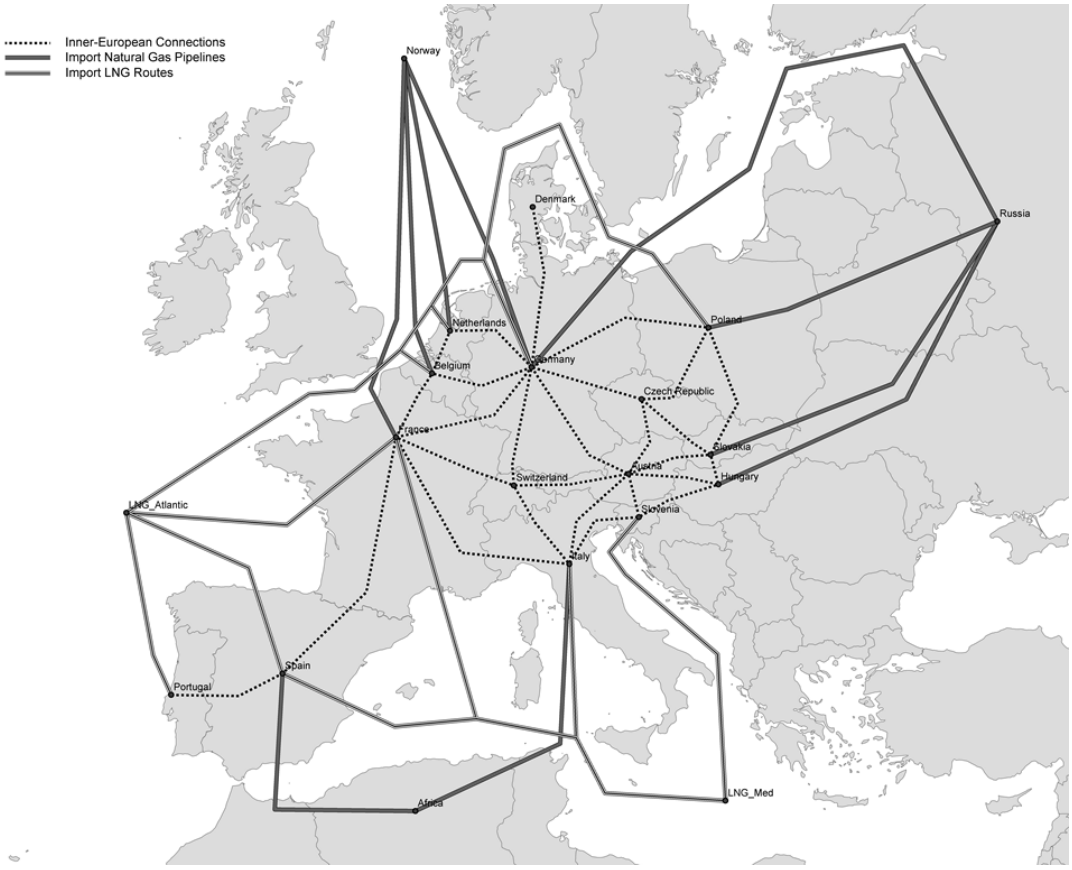

Figure 4: Stylized European Network Representation

4.1. Data and Scenarios

The European model focuses on Western and Central Europe up to the eastern borders of Poland, Slovakia, Hungary, and Slovenia (Figure 4). The respective natural gas and electricity networks are highly aggregated. Each country is represented by a single node and linked with its neighboring countries via aggregated connections representing 220kV and 380kV transmission lines, respectively, for the electricity network (ENTSO-E, 2013), and cross-border pipelines in the natural gas network (ENTSOG, 2013). The respective connection length is derived as the geographic distance between the country nodes. Furthermore, in the natural gas network, the main import options (Russia, Africa, and LNG from the Atlantic and Mediterranean) are included as virtual supply nodes and connected with the relevant European import country nodes.

Each node has the aggregated country's electricity generation plant capacity clustered into ten types following ENTSO-E (2013) with average plant efficiency values and ca-

pacity values. Demand is derived from the hourly load values as published by ENTSO-E and adjusted to match aggregated yearly demand with the values provided in ENTSO-E (2013). Three load segments are used - peak, mid-, and off-peak - which are derived by the hourly ordering load according to the total European demand level and taking the average values for each third, respectively. Natural gas demand is taken from IEA (2013) with natural gas production for European countries taken from Eurostat. The non-European gas producers are assumed to have unlimited production capacities. Their export potential is limited by the pipeline capacities towards Europe. We use the gas pipeline formulation to capture European LNG import options by transferring the LNG import capacities into pipeline capacities ($cap^{pipe}_{\tilde{g}g}$). The respective LNG export nodes (LNG-Atlantic and LNG-Mediterranean) are connected via "virtual pipelines" with the respective LNG import countries (see Figure 4). Fuel prices are based on 2012 values taken from BAFA for German import prices and adjusted to 90% for East European countries and 110% for South European countries. The production costs of the non-European gas producers are calibrated to derive a similar natural gas price level in the model as provided by BAFA (approx. 30 Euro/MWh).

Transmission investment costs are based on L'Abbate and Migliavacca (2011) with an assumed average of 0.5 Mio Euro per km for a 380kV line and 0.25 Mio Euro per km for a 220kV line. Natural gas pipeline costs are based on INGAA (2009) with an assumed average of 1 Mio Euro per km for a 32 inch pipeline. LNG investments only represent the regasification options within Europe, assuming sufficient export and transport capacity on the respective global LNG markets. The invested regasification capacity is added as pipeline capacity on the respective LNG route ($I^{pipe}_{\tilde{g}gT}$). We assume average investment costs for regasification of 85 Mio Euro per bcm based on the budget reports for the planned LNG terminals in Poland, Croatia and Ireland. Finally, gas-fired combined cycle investment costs are based on Schröder et al (2013) with an assumed average cost of 800 Euro per kW. For all investment costs, the annuity is derived using a lifetime of 20 years, and an interest rate of 4% for the network investments, and 7% for LNG and plant investments.

In order to test whether the European markets are subject to potential investment substitution effects, we derive a future scenario setting that provides incentives to extend both natural gas generation and transmission lines. Given the current objectives of European energy policy, it is expected that firstly, coal-fired generation will be penalized due to its higher CO_2 emissions, and that secondly, renewable generation will further increase its production share. To capture these two elements, we introduce a price markup for coal-based generation, equivalent to an emission price of about 100 Euro/tCO_2, which effectively pushes it out of the market, and we double the renewable production compared to 2012. This will in turn lead to more investment in gas-fired generation and subsequent investments in transmission lines and/or natural gas infrastructure. Similar to the simple test case setting, we vary the electricity transmission extension costs, while keeping the other parameters fixed. Beside the *base case* with the above-described cost setting, we simulate a *low-cost* case with a 50% lower and a *high-cost* case with a 50% higher electricity transmission investment cost level.

4.2. Results

Although simplified in nature, the model provides reasonable market results for a 2012 simulation. The natural gas market shows lower prices in East Europe and higher prices in South Europe. The LNG supply option plays a crucial role in supplying the Iberian markets, while Central Europe is supplied by endogenous production and Norwegian and Russian imports. The electricity market shows higher prices in countries that depend on gas production, such as Southern Europe and the Benelux countries. Prices during off-peak are on average about 70% of the medium price level, while peak prices represent about 110%. The lower markup between the mid- and peak-load segment is driven by the dominance of gas plants as marginal units in both load segments in many European countries. Congestion occurs mainly on lines towards Italy, as well as partially on lines from France towards Belgium and Spain, and between the Czech Republic and Austria.

The scenario analysis provides the first estimations of the interaction between both markets and the potential of investment substitution. Table 1 provides an overview on the investments that were carried out in the three cost scenarios. While it is not surprising to observe significantly higher transmission investments when the extensions costs are lower, the pattern over all three investment options shows a clear indication in support of substitution between gas and electricity infrastructure.

The most obvious example is the Italian situation. In the case of cheap electricity transmission extension costs (*low-cost case*), Italian electricity demand will be satisfied by imports from North and East Europe with Switzerland and Austria extending their cross-border capacities respectively. In the *base case* minimal transmission investments take place and existing gas fired generation is increased, especially during off-peak and mid load conditions, using an increased gas pipeline capacity to satisfy the increased gas demand in the electricity sector. Finally, in the case of high transmission extension cost (*high-cost case*), Italian demand is supplied by further extending the gas pipelines towards Italy and Slovenia and constructing new gas-fired plants in those countries, which avoids electricity transmission investments altogether.

A reversed impact can be observed in Poland. Poland faces low gas prices thanks to its proximity to Russia. The resulting low gas price coupled with the high dependence on coal in the initial market setting makes it profitable to invest into new gas plants in Poland. The generated electricity is then distributed towards the demand in West and South Europe. However, with increasing transmission costs, this incentive is greatly reduced, and consequently investments in gas plants in Poland decline, while plants are constructed in the original electricity import countries (i.e., Germany and Czech Republic).

Our examination shows that the main changes are within the electricity transmission system, ranging from approximately 28 GW of new capacity in the low-cost case to no investments in the high-cost case, followed by the pipeline system with a range from 12 to 25 GW, respectively. LNG capacities are not extended in any of the scenarios.

The power plant investments range from a total of 35 GW to 42 GW, but show some significant regional shifts. In case of average transmission investment costs (*base case*) we observe significant investments in Poland and new gas plants in Slovakia and Austria, as

Table 1: Investment Scenario Results

Costs Scenario	**50%**	**100%**	**150%**
Electricity Transmission Investment [GW]			
Spain - France	10.84	10.84	-
Germany - Poland	1.68	-	-
Poland - Czech Republic	4.80	3.06	-
Austria - Italy	2.91	-	-
Solvenia-Italy	0.66	-	-
Switzerland - Italy	7.35	0.21	-
Natural Gas Pipeline Investment [GW]			
Austria → Italy	9.92	18.83	20.00
Hungary → Slovenia	2.17	2.17	4.88
Gas Power Plant Investment [GW]			
Austria	-	0.32	-
Czech Republic	-	-	1.76
Denmark	1.09	1.95	2.02
Germany	-	-	1.38
Hungary	-	-	-
Italy	-	-	2.11
Netherlands	6.49	7.22	9.36
Poland	24.51	21.83	19.65
Slovakia	2.29	3.06	3.51
Slovenia	-	-	2.15

well as Denmark and the Netherlands. As indicated above in case of higher investment costs (*high-cost case*) a share of the new plants are allocated in the original demand countries, leading to more capacity additions in Italy, Slovenia and Poland's neighboring countries. On the contrary, in the *low-cost case* investments outside Poland are rather limited.

4.3. Discussion

As the model is designed to highlight the potential investment interaction and not provide an empirical estimate of Europe's energy future, the results should be considered cautiously with regard to actual developments in Europe. Nevertheless, the simulation shows the strong interdependence of the European natural gas and electricity markets. Naturally, the greater complexity of the European energy system makes predictions of changing market conditions more difficult without model based-assessments.

Compared to the simple test case networks we do not observe a clear-cut shift between investment alternatives. This is also a result of the interplay between using existing capacities and constructing new capacities. The general substitution between electricity and gas transport is not limited to new investments but can also be achieved by reallo-

cating flows on existing transport corridors; i.e. in the *high-cost case* in addition to the gas pipeline investments we also observe a shift in the natural gas flows reallocating gas destined for Poland in the *base case* to Italy via Hungary and Austria.

Naturally, the obtained patterns and numerical values are a result of the calibration and simplifications. In our scenarios the basic trade-off lies in the question how to best utilize cheap Russian gas imports. Different calibrations or scenarios will lead to varying investment and flow patterns. The point of the model is to show that it is indeed helpful to consider both markets when analyzing market developments as potential interactions can lead to shifts in the optimal spatial investment pattern.

The simplified model design does not capture seasonal fluctuation in energy markets or storage possibilities. Storage can help to reduce the need for investments in production or transport capacities as it presents an alternative to transfer energy between high and low load times. Consequently, our model should lead to an overestimation of investment amounts. Also investments on the electricity network are limited to upgrades on existing pathways. Consequently, if no connection or only a 220kV connection exists a new 380kV line cannot be constructed in the model.

The model does also not account for uncertainty in the short (i.e. stochastic renewable generation) or long run (i.e. demand and price uncertainty). The former can provide an additional incentive to invest in gas plants, to provide the needed system flexibility. The impact of the later varies with the underlying assumptions about future conditions in electricity and gas markets. Related to this is the assumed interest rate and amortization time: higher uncertainty in market developments and price patterns is likely to require higher rate of returns for investors. However, as long as the regulated segments (electricity transmission and gas pipelines) have lower rates than the unregulated segments (LNG and power plant investments) and similar life-time considerations the general trade-off effects identified by the model should remain valid.

The large differences in the investment cost of the assumed scenarios, ranging between 50% to 150%, are chosen to highlight the impact of cost ratios and not represent actual investment uncertainties. Albeit, current experiences with energy infrastructure investments both in electricity (e.g., the new nuclear plant in Scandinavia, and the lagging network extension in Germany) and natural gas (e.g., the discussion on Nabucco, South-Stream, and TAP) show that investment costs can easily increase due to NIMBY or regulatory-induced longer planning and construction phases. Coupled with further changes on the overall market conditions (i.e., the impact of U.S. shale gas on natural gas prices in Europe), the production and investment cost ratios can easily fluctuate and thereby change the optimal investment pattern in both markets.

Despite the restrictions of the underlying model the analysis shows that the interplay between both markets warrants a more holistic approach in their evaluation. Given the expectation that natural gas will play a major role in influencing electricity markets to adopt a high share of fluctuating renewables, policy decisions should not be solely based on an electricity market perspective. For the underlying network investments (i.e. the ENTSO Ten Year Network Development Plans) a closer collaboration seems feasible, as both transmission systems are already subject to regulation and European coordination approaches. Coordination between network investments and investments

in new power plans, storage facilities, or LNG terminals is more complicated as the later are competitive market decisions and not subject to direct regulation. This aspect also extends to the ongoing debate about capacity markets in electricity markets. Whether and how coordination between production and transmission can be achieved is a still open research question.

5. Conclusion

This paper has analyzed the interaction between natural gas and electricity investments while accounting for the network characteristics of both markets. We develop a dynamic model representation of a combined market framework. The model is formulated as a partial equilibrium representation using the MCP format. Although, the presented model is limited to production and transport aspects, the formulation allows an easy extension to capture further market actors, such as LNG traders or the dynamic nature of storage operations. The chosen model framework also enables an easy adoption of different market designs, i.e., oligopolistic competition on the production and generation markets and regulator mechanisms in the transmissions networks.

Applying the model to a four-node test case and a stylized representation of the continental European natural gas and electricity markets, we can present two important insights for future market evaluations. First, the nature of electricity transmission and the physics of power flows involves a high level complexity which needs to be captured in investment models to provide reasonable evaluations. This issue is techno-economic in nature and requires the inclusion of basic electrical-engineering elements in market models. A simplified representation of power flows via pure (directed) trade flows is likely to provide biased results.

Second, natural gas and electricity markets face mutual interdependence in investment decisions, which requires a combined approach in order to be adequately captured within model estimates. This paper has shown that it is necessary to produce an integrated assessment of alternative investments in energy production (i.e., pipeline and power plant investments vs. transmission line and plant investments) since their cost depend on the locational price spreads in their respective markets. Capturing this interaction in separated models is likely to provide biased results. The investment substitution aspect is furthermore amplified by the problems of meshed electricity networks.

The paper provides further insights relating to the ongoing discussion about the future development of market design in gas and electricity markets. Although, most of this discussion has focused on single aspects, i.e., the capacity market debate in electricity generation or the question about optimal network regulation to foster investments, it has also emphasized that they are importantly interlinked and therefore warrant a comprehensive approach. The model developed in this paper provides an analytical basis for assessing the feasibility of investments decisions within a network of markets for energy production and supply, and should help to formulate robust policy recommendations for the international challenges facing this sector.

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Appendix

A. Mixed Complementarity Formulations

A.1. Natural Gas Market Model

For the natural gas model, the MCP version is obtained by deriving the necessary (and sufficient as the problems are linear) first-order conditions of the optimization problems of the natural gas producer (equations 2 and 3), the pipeline trader (equations 4 and 5), and the pipeline operator (equations 6 and 7). The natural gas sub-model is closed by adding a market clearing condition for natural gas at supply (A.10) and demand nodes (A.9), as well as for pipeline transport services (A.11):

$$c_{gt}^{gas} + PC_{gt}^{gas} \geq PS_{gt}^{gas} \quad \perp \quad X_{gt}^{gas} \geq 0 \qquad \forall g, t \tag{A.1}$$

$$cap_{gt}^{gas} \geq X_{gt}^{gas} \quad \perp \quad PC_{gt}^{gas} \geq 0 \qquad \forall g, t \tag{A.2}$$

$$PS_{gt}^{gas} + PN_{\tilde{g}t}^{gas} \geq PD_{\tilde{g}t}^{gas} + PN_{gt}^{gas} \quad \perp \quad T_{g\tilde{g}t}^{gas} \geq 0 \qquad \forall g, \tilde{g}, t \tag{A.3}$$

$$PT_{g\tilde{g}t}^{pipe} + PN_{gt}^{gas} \geq PN_{\tilde{g}t}^{gas} \quad \perp \quad F_{g\tilde{g}t}^{gas} \geq 0 \qquad \forall g, \tilde{g}, t \tag{A.4}$$

$$\sum_{\tilde{g}} F_{\tilde{g}gt}^{gas} + \sum_{\tilde{g}} T_{g\tilde{g}t} = \sum_{\tilde{g}} F_{g\tilde{g}t}^{gas} + \sum_{\tilde{g}} T_{\tilde{g}gt} \quad \perp \quad PN_{gt}^{gas} \geq 0 \qquad \forall g, t \tag{A.5}$$

$$c_{g\tilde{g}t}^{pipe} + PC_{g\tilde{g}t}^{pipe} \geq PT_{g\tilde{g}t}^{pipe} \quad \perp \quad F_{g\tilde{g}t}^{pipe} \geq 0 \qquad \forall g, \tilde{g}, t \tag{A.6}$$

$$ci_{g\tilde{g}t}^{pipe} \geq PC_{g\tilde{g}t}^{pipe} \quad \perp \quad I_{g\tilde{g}t}^{pipe} \geq 0 \qquad \forall g, \tilde{g}, t \tag{A.7}$$

$$I_{g\tilde{g}t}^{pipe} + \overline{cap_{g\tilde{g}}^{pipe}} \geq F_{g\tilde{g}t}^{pipe} \quad \perp \quad PC_{g\tilde{g}t}^{pipe} \geq 0 \qquad \forall g, \tilde{g}, t \tag{A.8}$$

$$\sum_{\tilde{g}} T_{\tilde{g}gt}^{gas} \geq a_{gt}^{gas} + b_{gt}^{gas} PD_{gt}^{gas} \quad \perp \quad PD_{gt}^{gas} \geq 0 \qquad \forall g, t \tag{A.9}$$

$$X_{gt}^{gas} \geq \sum_{\tilde{g}} T_{g\tilde{g}t}^{gas} \quad \perp \quad PS_{gt}^{gas} \geq 0 \qquad \forall g, t \tag{A.10}$$

$$F_{g\tilde{g}t}^{pipe} \geq F_{g\tilde{g}t}^{gas} \quad \perp \quad PT_{g\tilde{g}t}^{pipe} \geq 0 \qquad \forall g, \tilde{g}t \tag{A.11}$$

A.2. Electricity Market Model

For the electricity market model, the MCP version is derived using the first-order conditions of the generators' maximization problem (equations 9 and 10) and the grid operator's maximization problem (equations 11 to 14). The electricity market model is closed

by adding the market clearing condition for electricity (15):

$$\sum_{f \text{ if } \eta_{if}>0} \frac{pf_{fekt} + \theta_f pe_{ekt}}{\eta_{if}} + PC^{ele}_{iekt} \geq P^{ele}_{ekt} \quad \perp \quad X_{iekt} \geq 0 \tag{A.12}$$

$$ci^{ele}_{iet} \geq \sum_k PC^{ele}_{iekt} \quad \perp \quad I^{ele}_{iekt} \geq 0 \tag{A.13}$$

$$I^{ele}_{iet} \geq X_{iekt} \quad \perp \quad PC^{ele}_{iekt} \geq 0 \tag{A.14}$$

$$P^{ele}_{ekt} + \lambda^Y_{ekt} = 0 \quad \perp \quad Y^{ele}_{ekt} \text{ free} \tag{A.15}$$

$$\sum_k \left(PC^{Line+}_{lt} + PC^{Line-}_{lt} \right) + \sum_k \left(\lambda^F_{lkt} \frac{\sum_e i_{le}\Delta_e}{x_l \overline{cap^{line}_{lt}}} \right) \leq ci^{line}_{lt} \quad \perp \quad I^{line}_{lt} \geq 0 \tag{A.16}$$

$$PC^{Line+}_{lkt} - PC^{Line-}_{lkt} \geq \sum_e i_{le}\lambda^Y_{ekt} - \lambda^F_{ekt} \quad \perp \quad F_{lkt} \geq 0 \tag{A.17}$$

$$\sum_l \lambda^F_{lkt} \frac{I^{line}_{lt} + \overline{cap^{line}_{lt}}}{\overline{cap^{line}_{lt}}} \frac{1}{x_l} \sum_e i_{le} = 0 \quad \perp \quad \Delta_l \text{ free} \tag{A.18}$$

$$I^{line}_{lt} + \overline{cap^{line}_{lt}} \geq F^{ele}_{lkt} \quad \perp \quad PC^{Line+}_{lkt} \geq 0 \tag{A.19}$$

$$F^{ele}_{lkt} \geq I^{line}_{lt} + \overline{cap^{line}_{lt}} \quad \perp \quad PC^{Line-}_{lkt} \geq 0 \tag{A.20}$$

$$\frac{I^{line}_{lt} + \overline{cap^{line}_{lt}}}{\overline{cap^{line}_{lt}}} \frac{1}{x_l} \sum_e i_{le}\Delta_e = F^{ele}_{lkt} \quad \perp \quad \lambda^F_{lkt} \text{ free} \tag{A.21}$$

$$Y^{ele}_{ekt} = \sum_l i_{le} F^{ele}_{lkt} \quad \perp \quad \lambda^Y_{ekt} \text{ free} \tag{A.22}$$

$$X_{ekt} = DEM^{ele}_{ekt} + Y_{ekt} \quad \perp \quad P^{ele}_{ekt} \text{ free} \tag{A.23}$$

B. Explanation of the electricity line flow equations

Following the DC-Load Flow approach, power flow F on a line l can be derived using the voltage angle difference Δ between the connected nodes. Assuming that the line's resistance is significantly smaller than the line's reactance x_l, the flow can be expressed as follows:

$$F_l = \frac{1}{x_l}\Delta_l \tag{B.1}$$

The extension of a given line can be considered as adding a second parallel circuit on the connection with a specific reactance value tied to the chosen capacity extension. Following the law of parallel circuits the total reactance of a line with several parallel circuits n can be expressed as follows:

$$\frac{1}{x_l} = \sum_n \frac{1}{x_n} \tag{B.2}$$

With X_n as the individual reactances of the different circuits composing the line l. If the line consists of N identical parallel circuits, the expression can be simplified to:

$$\frac{1}{x_l} = N\frac{1}{x_n} \tag{B.3}$$

Applied to the logic of line extensions: Adding a second identical line to an existing connection leads to a bisection of the initial reactance. Therefore, given an initial system with starting line capacities $\overline{cap_l^{line}}$ and respective line reactances $\overline{x}_l$, the impact of a line extension can be formulated as:

$$\frac{1}{x_l} = \frac{CAP_l^{line} + \overline{cap_l^{line}}}{\overline{cap_l^{line}}}\frac{1}{x_n} \tag{B.4}$$

This formulation is naturally an approximation, as line extensions are typically integer decisions, and capacity and reactance do not need to be in a fixed relation. It also requires an initial system and only allows extension of existing connections but no completely new connections. Furthermore, the decommissioning of a line is not possible, as this would require x_l to become infinite. Equation (13) in the main text results by substituting (B.4) back into equation (B.1) and accounting for nodal-based representation of the voltage angle ($\Delta_l = \sum_e i_{le}\Delta_e$).

C. Data

Table 2: Production Capacity and Cost

Node	Cheap	Medium	Expensive	Demand/New
Electricity System				
Initial capacity	50	50	50	-
Generation costs	10	20	30	-
Investment costs	24.5	24.5	24.5	24.5
Natural Gas System				
Initial capacity	unlimited	-	-	-
Supply costs	10	20	30	-

Table 3: Transmission Capacity and Cost

	Initial Capacity	**Investment Costs**	**Resistance**
Linear Electricity System			
Line 1	50		1
Line 2	50	variable	1
Line 3	100		0.5
Meshed Electricity System			
Line 1	25		1
Line 1.1	25		1
Line 2	25		1
Line 2.1	25	variable	1
Line 2.2	25		1
Line 3	50		0.5
Line 3.1	50		0.5
Line 3.2	50		0.5
Natural Gas System			
Pipeline 1	unlimited	-	-
Pipeline 2	unlimited	-	-
Pipeline 3	0	29.5	-

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