Short-term Price and Volume Interactions in an Integrated Gas & Electricity Market Framework
Discussion Paper

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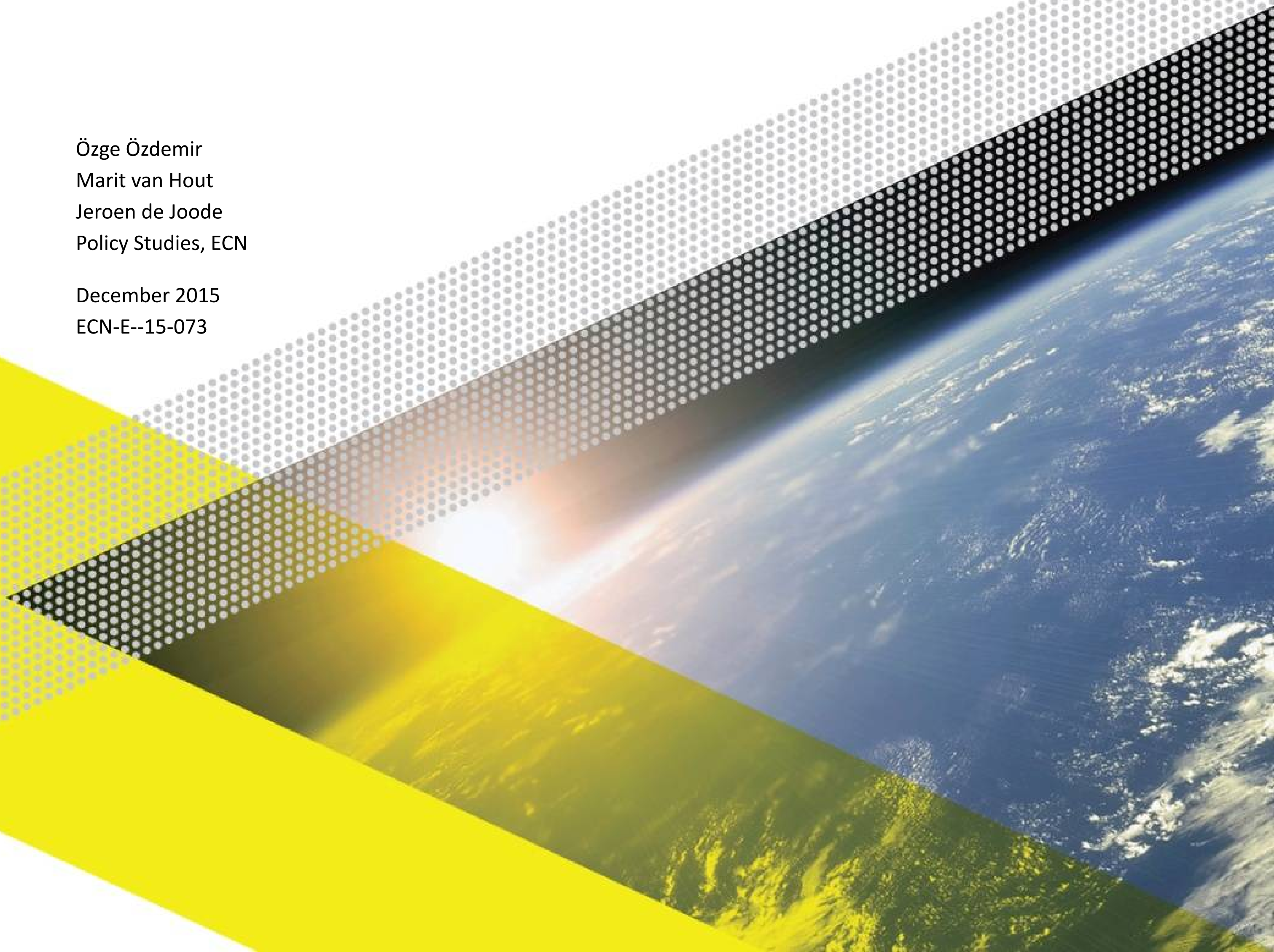

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Abstract

Gas and electricity (G&E) markets are interdependent due to the participation of natural gas fired power plants (NGFPPs) in both markets. Policy makers and regulators require tools to understand the implications of possible technology-, policy-, and economic developments in one market for the operation of the other. Although each market is studied extensively, i.e. by means of a gas market model or an electricity market model, these studies are confined to a certain extent in the sense that G&E market interdependencies are not considered, or at most, only in an iterative manner. In this paper, we propose an integrated gas- and electricity market model focusing on short-term interdependencies that relate to *price and volume interactions*. The short-run **I**ntegrated **EL**ectricity and **GAS** market (I-ELGAS) model is an economic equilibrium model for hourly price and volume interactions, that takes into account ramping rates of conventional units, intermittent renewable (I-RES) variability, seasonal- and peak gas storage, and electricity storage. We show that this equilibrium model can be formulated as a Quadratic Program (QP) under the assumption of perfect competition. This assumption allows for solving large-scale systems. The model is applied to a (four-node) system to analyse the impact of higher I-RES generation, higher CO_2 prices and different types of energy storage on the price and volume interactions in the gas- and electricity market.

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Introduction

The operations of natural gas fired power plants simultaneously affects the gas- and electricity markets

Gas markets and electricity markets are linked via natural gas fired power plants (NGFPPs) that operate as producers in the electricity market and as consumers in the gas market. As a result of the participation of NGFPPs in the electricity- and gas (G&E) markets, their operations simultaneously affect both markets with respect to prices and volumes. Thereby, the markets are interdependent. The electricity market is one of the largest consumers of gas whereas gas can be substituted by other lower cost fuels (e.g. coal) in case the gas price is sufficiently high. The operation of NGFPPs can also be affected by congestion of either gas- or electricity networks or both, as well as physical or political security of supply events (e.g. the Russia-Ukraine gas dispute of 2009). Other factors like the CO_2 price trajectory, market power (especially in the gas market), vertical mergers[1], network- and production capacity investments in both markets, also affect the level of interdependence between the G&E markets.

Furthermore, in the medium and longer term, gas is generally viewed as a transition fuel towards a low carbon, or carbon neutral future. With increasing shares of intermittent renewables (I-RES) which are unpredictable and variable by nature, an increase in the demand for flexible generation is expected. Since NGFPPs are highly flexible and hence well-suitable to accommodate sudden (short-term) changes in residual electricity demand (i.e. demand minus I-RES generation), an important role for gas is anticipated in the future electricity market. Besides the high flexibility of NGFPPs, these units also have lower carbon emission factors, are more efficient, and have relatively lower investment costs compared to other conventional generation technologies such as coal. Even though the current market situation is unfavorable for NGFPPs, their role as a conventional back-up technology remains important. Thereby, with the aim of a fully integrated European energy market, policy makers and regulators require tools to understand the implications of possible technology-, policy-, and economic developments in one market for the operation of the other, e.g. the impact of increasing intermittent renewables in the electricity market on the future role of gas.

Most of the studies analyzing the gas market or the electricity market by utilizing a single-market model are confined in the sense that G&E market interdependencies are not con-

1 An example of a vertical merger is when a gas supplying company and an NGFPP merge. In general, vertical mergers reduce inefficiencies from transactions

To our knowledge, none of the existing models that focus on short-term interactions differentiates the flexibility properties of different sources in both markets in such detail as the I-ELGAS model

sidered, or at most, only in an iterative manner. In this paper, we introduce an integrated G&E market market model that accounts for interactions of gas- and electricity markets while simultaneously representing the infrastructure in both markets (i.e., transmission of electricity and gas, the storage of electricity and gas, and LNG liquefaction and regasifications terminals). The G&E markets are linked via the NGFPPs where the natural gas price is endogenous to the gas market but exogenous to the electricity market, and the natural gas demand of the power sector is endogenous to the electricity market but exogenous to the gas market. The model is formulated using an equilibrium/optimization framework that simultaneously calculates the short-term energy balance and price equilibrium in both G&E markets under a perfect competition assumption (price-taking behaviour).

There exists a number of studies using an equilibrium/optimization framework for modelling interactions between G&E markets, but the available literature is relatively scarce. The majority of these models focus on short-term interactions (e.g., [5, 11, 6, 2, 1]). Only a few G&E market models include long term interactions by endogenizing investments in an integrated framework (e.g. [16, 17, 3, 4]). However, as pointed out by [1], most of these models are in general too complex to solve for large-scale systems or do not represent the economic aspects of the gas and electricity market well due to the non-linearities or integer variables. Thereby, the geographical and/or temporal scope is limited to a system with few nodes or periods. For example, in [16] a Gas and Electricity Optimal Power Flow (GEOPF) model is applied to the IEEE 14-node test system and the Belgian calorific gas network. While technical and physical details can be well represented by the GEOPF, the use of integer variables leads to problems concerning price variables. In [11] and [6], the OPF is applied in a more general fashion by using the energy hub concept. Within the energy hubs, energy carriers among which natural gas can be converted to an output such as electricity. While in the former, computational limitations are expected with larger-sized systems, the latter uses a decomposition technique to solve for larger-sized systems.

[2] and [1] use a Mixed Complementarity Problem (MCP), a common formulation of energy market equilibrium problems ([10]), to integrate gas and electricity markets while representing the physical energy networks and the economic aspects. In [1], the model is applied to a large geographical scope (i.e. a stylized representation of Europe). However, it is a single-period model and the energy storage, which is an important flexibility source, is not included. In this paper, we present a *short-run* **I**ntegrated **EL**ectricity and **GAS** (I-ELGAS) market model. Our model is an extension of [2] and [1] in the sense that it includes flexibility limitations of conventional power plants (i.e., ramping rates), peak- and seasonal gas storage, electricity storage, and I-RES variability with multiple periods with an hourly resolution. To our knowledge, none of the existing models focusing on short-term interactions differentiates the flexibility properties of different sources in both markets in such detail.

The I-ELGAS model is formulated as an MCP ([10]). Models formulated as MCPs can be solved by specialized algorithms ([8]) or, in special cases, by formulating an equivalent single optimization model instead. Formulation of a single optimization problem may not be possible for general complementarity problems, but it is often feasible for problems formulated assuming perfectly competitive markets (see, e.g., [10], [14]). Large-scale complementary models for real world problems are computationally complex to solve. Therefore, we adopt the single optimization approach by formulating and solving an equivalent Quadratic Program (QP). With QP formulation, we can solve millions of variables including variability of demand and renewables and energy storage within reasonable solution times.

We apply our model to a four node system analysing scenarios with different levels of CO_2 prices, I-RES generation and different types of energy storage capacities. The results give insights regarding the effects of intermittent renewables in the electricity market on the demand and price of natural gas. In addition, the role of gas and electricity storage capacity in accommodating the effects of intermittent renewable electricity sources have been explored. Although the conclusions cannot be generalized yet to the European system since the results are derived based on a limited system size, our modelling approach allows for a more detailed analysis of energy systems on a large geographical scale. In the future, the model will be extended to a stylized European scope similar to ECN's European gas market model GASTALE ([7]) and the European electricity market model COMPETES ([15] and [18].

The paper is organized as follows; Section 2 presents the modelling approach providing the mathematical formulations and the description of each market player's problem in addition to the equivalent single optimization problem. Section 3 illustrates our observations from the application of our model to a four country system, analyzing various scenarios, i.a. with higher I-RES shares, a higher CO_2 price and higher levels of either seasonal gas storage, peak gas storage, or electrical storage. Section 3.3 presents the conclusions. The notation used throughout the paper is given in section 4.

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Modelling approach

We describe our modelling approach in two steps: First, we formulate a market equilibrium problem for a single year that assumes perfect competition, i.e. price-taking behavior, among all market parties in both the G&E markets. Each market party pursues its own objective (e.g., maximization of its surplus) where at equilibrium, each one's objective is achieved such that they cannot increase their surplus by deviating from the equilibrium solution. This is modelled by formulating the maximization problem for each party and then deriving the first-order (Karush-Kuhn-Tucker, KKT) conditions. Moreover, the market clears at the equilibrium price where supply equals demand for energy. The KKT conditions for all market parties and the market clearing conditions together yield the "*Mixed Complementarity Problem (MCP)*" for the entire market. Second, we state a single optimization problem that is equivalent to the MCP, which allows solving larger systems efficiently. A solution to the single optimization problem is also a solution to the MCP. Thereby, under perfect competition, the market equilibrium represents the least cost solution of the entire system which is optimal for all the market players combined.

Market players are assumed to be price-takers. Hence, while gas- and electricity prices are *endogenous* to the market as a whole, prices are *exogenous* to the market players

The model is static, taking the capacities of gas and electricity production and infrastructure as given. In the next section the formulation of the market equilibrium problem is given for each market player and the equivalent single optimization problem. The nomenclature is provided in section 4. Under perfect competition, each market player is a price taker and views prices as fixed. Price taking behavior can be modelled by formulating the price as an exogenous parameter in each market player's problem even though it is endogenous to the market as a whole.

2.1 The gas market model

The gas market consists of gas producers, consumers, Transmission System Operators (TSOs), and Storage System Operators (SSOs), where each group strives different objectives as explained below.

Gas producers: The producers of gas in the origin countries sell their gas to consumers in gas consuming countries (i.e., the residential sector, the industrial sector and the power sector). In order for the gas producers to provide gas to their consumers, they buy transportation capacity (LNG and pipeline capacity) from the TSO. Thereby, they gain revenues by selling gas to the consumer sectors and incur the cost of producing and transporting gas. The production and trading arms of the producing firms are assumed as single entity, although in reality they are in general unbundled. Under perfect competition, the solution is not affected if the production and trading arms are unbundled or not.

In order to maximize their profits, each gas producer z chooses its sales s^g_{zip} earning the gas price $price^g_{ip}$; it also chooses its production q^g_{zop} and transmission amount via pipelines (t^g_{zoip}) or LNG (tl^g_{zoip}) paying the production cost $(CQ^g(q^g_{zop}))$ and price of transmission (wt^g_{kp}, wtl^g_{oip}). For given gas and transmission prices ($price^g, wt^g, wtl^g$), each natural gas producer $z \in Z$ has the following optimization problem:

$$\max_{s^g,q^g,t^g,tl^g} \sum_{p\in P} N_p \Bigg[\sum_{i\in I} price^g_{ip} s^g_{zip} - \sum_{o\in O} \bigg(\sum_{i\in I} (\sum_{k\in K} GTC_{oik} wt^g_{kp} t^g_{zoip} + LTC_{oi} wtl^g_{oip} tl^g_{zoip}) + CQ^g(q^g_{zop}) \bigg) \Bigg] \quad (2.1)$$

$s.t.$

$$s^g_{zip} - \sum_{o\in O}(t^g_{zoip} + tl^g_{zoip}) = 0 \quad (\theta^s_{zip}) \quad \forall p \in P, i \in I \quad (2.2)$$

$$-q^g_{zop} + \sum_{i\in I}(t^g_{zoip} + tl^g_{zoip}) = 0 \quad (\theta^p_{zop}) \quad \forall p \in P, o \in O \quad (2.3)$$

$$\sum_{i\in I} tl^g_{zoip} \leq TLG^{out}_{zo} \quad (\gamma^{out}_{zop}) \quad \forall p \in P, o \in O \quad (2.4)$$

$$q^g_{zop} \leq Q_{zo} \quad (\mu_{zop}) \quad \forall o \in O \quad (2.5)$$

$$q^g_{zop}, t^g_{zoip}, tl^g_{zoip}, s^g_{zip} \geq 0 \quad \forall p \in P, o \in O, i \in I. \quad (2.6)$$

Eqs. (2.2) and (2.3) correspond to the mass balance of sales, production, and transport. LNG liquefaction capacity is assumed to be owned by the production firm and LNG production is limited by LNG liquefaction capacity in Eq. (2.4). The production of gas is limited by total production capacity in Eq. (2.5). Eq. (2.6) ensures the nonnegativity of gas producers's decisions.

Gas TSO: The TSO allocates pipeline and LNG liquefaction capacity to the gas producers with total costs $CZ^g_k(flow^g_{kp})$ and $CX^g_{oi}(x_{oip})$ respectively. The price-taking behaviour of the TSO leads to an efficient allocation of scarce transmission and LNG capacity, serving demand on a least-cost basis.

For given transmission prices (wt^g, wtl^g), the TSO chooses pipeline flows ($flow^g_{kp}$) and LNG flows (x_{oip}) to maximize the value of its services, revenues minus the cost of transmission, associated with pipeline transport and LNG shipment are defined as:

$$\max_{flow^g,x^g} \sum_{p\in P} N_p \cdot \Bigg[\sum_{k\in K} (wt^g_{kp} \cdot flow^g_{kp} - CZ^g_k(flow^g_{kp})) + \sum_{o\in O}\sum_{i\in I}(wtl^g_{oip} \cdot x^g_{oip} - CX^g_{oi}(x_{oip})) \Bigg] \quad (2.7)$$

$s.t.$

$$flow^g_{kp} \leq TG^g_{kp} \quad (\psi^g_{kp}) \quad \forall k \in K, p \in P \tag{2.8}$$

$$\sum_{o \in O} x^g_{oip} \leq TLG^{in}_{ip} \quad (\gamma^{in}_{ip}) \quad i \in I, p \in P \tag{2.9}$$

$$flow^g_{kp}, x^g_{oip} \geq 0 \qquad \forall o \in O, i \in I, k \in K, p \in P. \tag{2.10}$$

Flows through pipelines are constrained by the capacity of the pipelines in Eq. (2.8) and LNG flows are constrained by the capacity of regasification in Eq. (2.9). The LNG marine shipping capacity is assumed to be unrestricted. Eq. (2.10) ensures nonnegativity of flows.

System storage operator (SSO): The SSO operates the storage capacity. In order to address the ability to mitigate a security of supply event in the electricity sector e.g., due to intermittency, we distinguish the flexibility of gas storage units by considering both seasonal and peak gas storage facilities. Peak facilities (i.e., salt caverns) are highly flexible and are able to extract and inject gas from storage throughout the year on an hourly basis. Seasonal gas storage facilities (i.e., depleted fields and aquifers) have a relatively low flexibility since these facilities are committed to injection in the warm seasons (i.e. spring and summer) and committed to extraction in the cold seasons (i.e. fall and winter). Furthermore, peak load storage facilities have higher injection and extraction rates but they operate at relative high costs. Hence, seasonal gas storage is better suited to accommodate seasonal demand fluctuations whereas peak gas storage is better suited to accommodate extreme demand fluctuations throughout the year.

Similar to the TSO, the SSO is also a price taker, resulting in an efficient allocation of storage capacity. Each storage operator f maximizes its profits from injection of gas (inj^g_{ifp}) in the low priced periods and extraction of gas to the consumers (e^g_{ifp}) in the high priced periods. In our model, we assume a yearly cycle for gas storage. Annual revenues of an SSO are gained by selling extracted gas at the market price. Its annual operational costs consist of the purchase of injected gas at the market price and total storage costs ($CS^g_i(inj^g_{ifp})$). The SSO's profit is the price difference between selling and the purchase of gas during extraction and injection, respectively, minus storage costs:

$$\begin{aligned} &\max_{inj^g, e^g} \sum_{i \in I, f \in F, p \in P} N_p \Big[price^g_{ip}(e^g_{ifp} - inj^g_{ifp}) - CS^g_i(inj^g_{ifp}) \Big] \\ &s.t. \end{aligned} \tag{2.11}$$

$$inj^g_{ifp} \leq SIR^g_{if} \quad (\omega^{inj}_{ip}) \quad \forall i \in I, f \in F, p \in P \tag{2.12}$$

$$e^g_{ifp} \leq SER^g_{if} \quad (\omega^{e}_{ip}) \quad \forall i \in I, f \in F, p \in P \tag{2.13}$$

$$\sum_{p \in P(cold)} N_p e^g_{ifp} \leq SC^g_{if} \quad (\omega^s_i) \quad \forall i \in I, f \in Seasonal \tag{2.14}$$

$$\sum_{p \in P} N_p e^g_{ifp} \leq SC^g_{if} \quad (\omega^p_i) \quad \forall i \in I, f \in Peakload \tag{2.15}$$

$$\sum_{p \in P(cold)} N_p e^g_{ifp} \leq \sum_{p \in P(warm)} N_p inj^g_{ifp} \quad (\Omega^s_{if}) \quad \forall i \in I, f \in Seasonal \tag{2.16}$$

$$\sum_{p \in P} N_p e^g_{ifp} \leq \sum_{p \in P} N_p inj^g_{ifp} \quad (\Omega^p_{if}) \quad \forall i \in I, f \in Peakload \tag{2.17}$$

$$e^g_{ifp}, inj^g_{ifp} \geq 0 \qquad \forall i \in I, f \in F, p \in P. \tag{2.18}$$

Gas storage operates under a number of technical constraints such as the limitations on the maximum hourly injection rates (Eq. (2.12)), the extraction rates (Eq. (2.13)) and on the maximum working storage capacity during their cycle (i.e., Eqs. (2.14) and (2.15)). In Eqs. (2.16) and (2.17), the balance between total injection and extraction quantities is taken into account while Eq. (2.18) gives nonnegativity conditions for the decision variables of storage.

Gas consumers: Final gas consumers are distinguished by three different market sectors; the power sector, the industrial sector, and the residential sector. The demand from the industrial and the residential sectors are represented by a linear demand function satisfying the following equilibrium conditions:

$$0 \leq price^g_{ip} - (A^g_{mip} + B^g_{mip} D^g_{mip}) \perp D^g_{mip} \geq 0, \quad m \in \{Ind, Res\}$$

The parameters $A^g_{imp} > 0$ and $B^g_{imp} < 0$ are estimated using the assumed elasticities together with the reference gas consumption and gas price in historical years. The elasticity from the industrial and the residential sectors are taken from [13] and [9] as -0.40 and -0.25 respectively. Different from single gas market models, the demand response of the power sector is endogenously determined via the gas power producer's problem in the electricity sector as formulated in Eq. (2.43) of Section 2.3.

Gas market clearing conditions: The market clearing conditions are the equilibrium conditions where prices are set at the balance of total quantity supplied and total quantity demanded. The market prices are endogenous to the whole system and represented by the Lagrange multipliers of these conditions. Eq. (2.19) clears the gas market at gas prices where total sales from producers and storage operators are equal to the total consumption of storage and gas consumers.

Note that the total gas consumption from the power sector is endogenous and depends on the generation of NGFPPs in the electricity sector as formulated in Eq. (2.43) of Section 2.3. The transmission prices (wt^g_{kp}) are Lagrange multipliers of Eq. (2.20), that satisfies the balance between transmission flows over the pipelines and the total demand for pipeline capacity by the producers. Eq. (2.21) satisfies the balance of LNG services demanded by the producers and provided by the TSO at the equilibrium LNG transmission price (wtl^g_{oip}).

$$\sum_{z \in Z} s^g_{zip} + e^g_{ifp} = inj^g_{ifp} + \sum_{m \in M} D^g_{mip} \quad (price^g_{ip}) \quad \forall i \in I, p \in P, f \in F. \tag{2.19}$$

$$flow^g_{kp} = \sum_{z \in Z} \sum_{o \in O} \sum_{i \in I} GTC_{oik} t^g_{zoip} \quad (wt^g_{kp}) \quad \forall k \in K, p \in P. \tag{2.20}$$

$$x^g_{oip} = LTC_{oi} \sum_{z \in Z} tl^g_{zoip} \quad (wtl^g_{oip}) \quad \forall o \in O, i \in I, p \in P. \tag{2.21}$$

2.2 The electricity market model

We consider a perfectly competitive electricity market consisting of generation units, large scale e-storage operators, a transmission system operator (a TSO), and consumers. Similar to gas market players, each market agent achieves different objectives as explained below.

Electricity generators: The power producers at node i are characterized by their generation type, available capacity, and technical capabilities to ramp up and down. The flexibility of generation units are differentiated via their ramping capabilities. The generators produce electricity incurring operational and maintenance cost and gain revenues by selling electricity to the TSO at the electricity market price. At given market price, $price^e_{ip}$, each generator $h \in H$ located in $i \in I$ chooses its generation, g^e_{ihp}, to maximize its short term profit under certain capacity and technical limitations:

$$\max_{g^e} \sum_{p \in P} N_p \cdot \left[price^e_{ip} \cdot g^e_{ihp} - C^e(g^e_{ihp}) \right] \tag{2.22}$$

$$s.t.$$

$$g^e_{ihp} - AF^e_{ih} G^e_{ih} \leq 0 \quad (\beta^e_{ihp}), \quad \forall p \in P \tag{2.23}$$

$$g^e_{ihp+1} - g^e_{ihp} - RR^e_{ih} \leq 0 \quad (\overline{\tau}^e_{ihp}), \quad \forall p \in P \tag{2.24}$$

$$-g_{ihp+1} + g^e_{ihp} - RR^e_{ih} \leq 0 \quad (\underline{\tau}^e_{ihp}), \quad \forall p \in P \tag{2.25}$$

$$g^e_{ihp} \geq 0 \qquad \forall p \in P. \tag{2.26}$$

In the objective function, the total operational and maintenance cost, $C^e(g^e_{ihp})$, depends on the efficiency of the unit and the given fuel and carbon prices:

$$C^e(g^e_{ihp}) = (\frac{FP^e_{ihp}}{\eta^e_{ih}} + \frac{\Theta^e_h PCO2^e}{\eta^e_{ih}} + OM^e_{ih}) * g^e_{ihp} \tag{2.27}$$

The fuel prices, except for the gas price, are exogenous to the model. The gas prices are determined endogenously by the integrated electricity and gas system as formulated in Eq. (2.41) of Section 2.3.

Each generation unit operates under a set of technical constraints such as limitations on generation capacity in Eq. (2.23), ramping up capability in Eq. (2.24), and ramping down capability of the unit in Eq. (2.25). For intermittent renewables such as wind and solar, the availability factor AF^e_{ih} represents the hourly variability of their generation. The Lagrange multipliers associated with these constraints indicate the shadow prices; that is the marginal value of increasing the capability of these limitations. For instance, β^e, associated with the shadow price of the capacity constraints represents the additional margin a unit gets to cover its capacity cost which is also referred as *"capacity or scarcity rent".*

Electricity TSO: We consider a pool-market model where the TSO buys power directly from the generators and sells it to the consumers. Specifically, the TSO, being a price taker, efficiently acts as an arbitrageur. The operator's objective is to choose net imports/exports of electricity to/from node i, y^e_{ip}, to maximize the value of its transmission services (i.e., revenues obtained from this arbitrage):

$$\max_{y^e, flow^e} \sum_{i \in I, p \in P} N_p price^e_{ip} y^e_{ip} \tag{2.28}$$

$$s.t.$$

$$\sum_{i' \in J(i)} \left[flow^e_{ii'p} - flow^e_{i'ip} \right] + y^e_{ip} = 0 \qquad (v_{ip}), \qquad \forall i \in I, p \in P \tag{2.29}$$

$$\sum_{i \in I} y^e_{ip} = 0 \qquad (\overline{v}_p), \qquad p \in P \tag{2.30}$$

$$flow^e_{ii'p} - T^e_{ii'} \leq 0 \quad (wt^e_{ii'p}), \quad \{\forall i' \in J(I)\}, \forall p \in P \tag{2.31}$$

$$flow^e_{ii'p} \geq 0 \qquad \{\forall i \in I, i' \in J(I), p \in P\} \tag{2.32}$$

The TSO manages import and export flows between countries as long as there is capacity to trade. In Eqs. (2.29)-(2.30), the total imports and exports should be in balance.

While the TSO dispatches electricity, it also operates the transmission network satisfying the cross-border transmission limitations (Eq. (2.31)). The trading capacities $T^e_{ii'}$ are represented by the so called Net Transfer Capacities (NTC) between the countries.

Electricity storage operator: We mainly focus on the bulk electricity storage technologies such as hydro pumped storage and compressed air energy storage (CAES). These electricity storage operators buy power by charging during low priced hours and sell power by discharging during high priced hours. By doing so, they are able to increase or decrease system demand for electricity and contribute to the flexibility for balancing generation and demand.

The objective of the storage operator is to choose their discharge (ds^e_{irp}) and charge (ch^e_{irp}) quantities maximizing their profits. The profit of each storage operator is equal to the revenues of discharging minus the costs of charging electrical energy within their cycle. Equal to the gas storage, a yearly cycle is assumed for the storage of electricity, where *T* represents the final period:

$$\max_{ch^e, ds^e, SOL^e_{irp}} \sum_{p \in P} N_p \sum_{i \in I, r \in R} \left[price^e_{ip}(ds^e_{irp} - ch^e_{irp}) - CR^e(ch^e_{irp}) \right] \tag{2.33}$$

s.t.

$$ch^e_{irp} - PS^e_{ir} \leq 0 \quad (\mu^a_{irp}) \quad \forall i \in I, r \in R, p \in P \tag{2.34}$$

$$ds^e_{irp} - PS^e_{ir} \leq 0 \quad (\mu^b_{irp}) \quad \forall i \in I, r \in R, p \in P \tag{2.35}$$

$$SOL^e_{irp} = ISC^e_0 + ch^e_{irp} eff^r - ds^e_{irp}/eff^r \quad (\mu^c_{irp}) \quad \forall i \in I, r \in R, p = 1 \tag{2.36}$$

$$SOL^e_{irp} = SOL^e_{irp-1} + ch^e_{irp} eff^r - ds^e_{irp}/eff^r \quad (\mu^d_{irp}) \quad \forall i \in I, r \in R, p > 1 \tag{2.37}$$

$$SOL^e_{irp} = ISC^e_{r0} \quad (\mu^T_{ir}) \quad \forall i \in I, r \in R, p = T \tag{2.38}$$

$$SOL^e_{irp} - SC^e_{ir} \leq 0 \quad (\overline{\mu}_{irp}) \quad \forall i \in I, r \in R, p \in P \tag{2.39}$$

$$ch^e_{irp}, ds^e_{irp}, SOL^e_{irp} \geq 0 \qquad \forall i \in I, r \in R, p \in P. \tag{2.40}$$

The amount of power charged and discharged is limited by the production capacity of storage in Eqs. (2.34) and (2.35), respectively. Constraints (2.36) and (2.37) indicate the level of e-storage at period p after charging or discharging. Constraints (2.36) and (2.38) set the initial and final energy levels of electricity stored in a cycle and constraint (2.39) is the maximum limit for electricity stored at period p.

Electricity consumers: We consider hourly profiles of demand. Final demand for electricity is assumed to be exogenous to the model and completely inelastic. No distinction is made between the various electricity consumers (e.g. industrial, residential).

Electricity market clearing conditions: Similar to the gas market model, the market clearing conditions satisfy the balance of total quantity supplied and total quantity demanded. The electricity market prices are endogenous to the whole system and are represented by the Lagrange multipliers of these conditions. In Eq. (2.41), electricity demand and supply are in balance at each node i and period p. In Eq. (2.42), when demand is curtailed during contingency hours ($ENS_{ip} > 0$), the price is set at the value of lost load ($VOLL^e$).

$$\sum_{h \in H} g^e_{ihp} + \sum_{r \in R} (ds^e_{irp} - ch^e_{irp}) + y^e_{ip} + ENS^e_{ip} = D^e_{ip} \quad (price^e_{ip}), \quad \forall i \in I, p \in P \tag{2.41}$$

$$0 \leq VOLL^e - price^e_{ip} \perp ENS_{ip} \geq 0, \quad \forall i \in I, p \in P \tag{2.42}$$

2.3 Market equilibrium conditions of the integrated electricity and gas markets

The interactions between electricity and gas markets can be categorized in two ways. First, the electricity market is one of the largest consumers of natural gas. The gas consumption of NGFPPs in the electricity market affects the volume of gas demand (see condition (2.43)) and consequently influences the gas prices in the gas market. Second, the natural gas market price directly affects the generation costs and dispatch of NGFPPs in the electricity sector (see condition (2.44)) and consequently determines the gas consumption from the power sector. Hence, there is an equilibrium for the total gas consumed by the power sector and the gas prices in the gas market. This equilibrium from the coupling of electricity and gas markets can be achieved via the following market equilibrium conditions:

$$D^g_{(Pow)ip} = \quad CONVF \cdot \sum_{h \in H(ngp)} \frac{g^e_{ihp}}{\eta^e_{ih}} \tag{2.43}$$

$$FP_{ihp} = \quad CONVF \cdot price^g_{ip} \qquad \forall h \in H(ngp) \tag{2.44}$$

Eqs. (2.43) and (2.44) can be incorporated in the formulation of market clearing condition (2.19) and Eq. (2.27) for gas units, respectively. Then the KKT conditions are derived for each market agent's optimization problem formulated in Sections 2.1 and 2.2. The resulting KKT conditions of each agent's optimization problem in the electricity and the gas market, together with the market clearing conditions, define the equilibrium problem which is a square system of nonlinear complementarity and/or equality conditions. This complementarity problem could be solved for the market equilibrium by using commercial complementarity solvers such as PATH ([8]).

However, nonlinear complementary problems for large scale systems are computationally challenging. This is also what we experienced when running I-ELGAS under an MCP formulation. With increase in the number of variables and constraints to only a few thousand, as in line with the limited four-node system presented in Section 3, the run times increased to over an hour. To reduce computational complexity we take another approach as described in the next section that allows for solving large scale systems with millions of variables. By adopting this approach, the run times of the I-ELGAS model applied to four-node system are reduced to only a few seconds.

2.4 Finding the equilibrium via a single optimization problem

In some cases, mixed complementarity models can be formulated as an equivalent single optimization model. The formulation of a single optimization problem may not be possible for general complementarity problems, but it is often feasible for problems formulated assuming perfectly competitive markets (see, e.g., [10], [14]).

Under the convexity assumption of the cost function $CQ_z(q_{zop})$ of gas producers, we can formulate a single optimization problem whose KKT conditions are equivalent to the concatenation of the KKT conditions of all the market agents and market clearing conditions described in sections 2.1, 2.2, and 2.3. The optimal solution of the single optimization problem given below must satisfy the model's KKT conditions, and therefore the solution is also a market equilibrium:

$$\max \quad WTP_{GAS} - COST_{ELEC} - COST_{GAS} - \sum_{i \in I, p \in P} VOLL^e * ENS^e_{ip} \tag{2.45}$$

s.t.

$$
\begin{aligned}
&Gas \quad Producers' \quad Constraints: \quad [2.2]-[2.6] \qquad \forall z \\
&Gas \quad TSO \quad Constraints: \quad [2.8]-[2.10] \\
&Gas \quad SSO \quad Constraints: \quad [2.12]-[2.18] \\
&Gas \quad Market \quad Clearing \quad Constraints \quad [2.20]-[2.21] \\
&Electricity \quad Generators' \quad Constraints: \quad [2.23]-[2.26] \qquad \forall i,h \\
&Electricity \quad TSO \quad Constraints: \quad [2.29]-[2.32] \\
&Electricity \quad Storage \quad Constraints: \quad [2.34]-[2.40] \\
&Electricity \quad Market \quad Clearing \quad Constraints: \quad [2.41]
\end{aligned}
$$

$$Electricity/Gas \quad Market \quad Coupling:$$

$$
\begin{aligned}
\sum_{z \in Z} s^g_{zip} + e^g_{ifp} = inj^g_{ifp} + \sum_{m \in \{Ind,Res\}} D^g_{mip} + CONVF \\
\cdot \sum_{h \in H(ngp)} \frac{g^e_{ihp}}{\eta^e_{ih}}(price^g_{ip}) \quad \forall i \in I, p \in P, f \in F
\end{aligned} \tag{2.46}
$$

$$ENS \geq 0$$

where,

$$WTP_{GAS} = \textstyle\sum_{i \in I, p \in P} N_p \sum_{m \in \{Ind,Res\}} (A^g_{mip} + B^g_{mip} D^g_{mip}) D^g_{mip}$$

$$
\begin{aligned}
COST_{GAS} = \textstyle\sum_{p \in P} N_p \Big[\sum_{z \in Z, o \in O} CQ^g(q_{zop}) + \sum_{k \in K} CZ^g_k(flow^g_{kp}) \\
+ \textstyle\sum_{o \in O, i \in I} CX^g_{oi}(x_{oip}) + \sum_{i \in I} CS^g_i(inj^g_{ifp}) \Big]
\end{aligned}
$$

$$
\begin{aligned}
COST_{ELEC} = \textstyle\sum_{i \in I, p \in P} N_p \Big[\sum_{h \in OTH} C^e(g^e_{ihp}) + \sum_{r \in R} CR^e(ch^e_{irp}) \\
+ \textstyle\sum_{h \in NGP} (\frac{\Theta_h PCO2}{\eta^e_{ih}} + OM^e_{ih}) * g^e_{ihp} \Big]
\end{aligned}
$$

In the objective function, WTP_{GAS} is the willingness to pay of the gas consumers in the industrial and residential sectors. $COST_{GAS}$ is the sum of the gas production costs, pipeline transmission and LNG shipping costs, and storage costs in the gas market, and $COST_{ELEC}$ is the sum of the generation costs and storage costs in the electricity market, excluding the fuel cost of NGFPPs. The objective can be interpreted as the total surplus for the gas and electricity market, which is defined as the sum of the objectives of all the agents in the gas and electricity market. It must be noted that all revenue terms of the objective functions of the individual players cancel each other. This includes the fuel cost of NGFPPs that are revenues to the gas market. Furthermore, constraint 2.46 results from combination of the market clearing conditions (2.19) and (2.43).

In the numerical analysis presented in section 3, we assume linear cost function $CQ_z(q_{zop})$ of gas producers.[2] Thus, optimization problem (2.45) is a Quadratic Program (QP). Thereby, we can use out-of-the-box algorithms that can efficiently solve very large QPs.

2 The non-linear gas production cost function of [12] is approximated by a piecewise linear production function.

3 Numerical analysis

3.1 Modelling assumptions and scenarios

We test our model with a four-node set-up as shown in Figure 1. Data of Norway, Russia, Germany and the Netherlands is used to represent the four interconnected nodes. Germany and the Netherlands are consumers of both electricity and gas. The Netherlands is also a producer of natural gas whereas Germany fully relies on foreign gas supply and domestic gas storage. Furthermore, Russia and Norway are included in the model only as gas supplying countries that differ with respect to the production costs of gas.

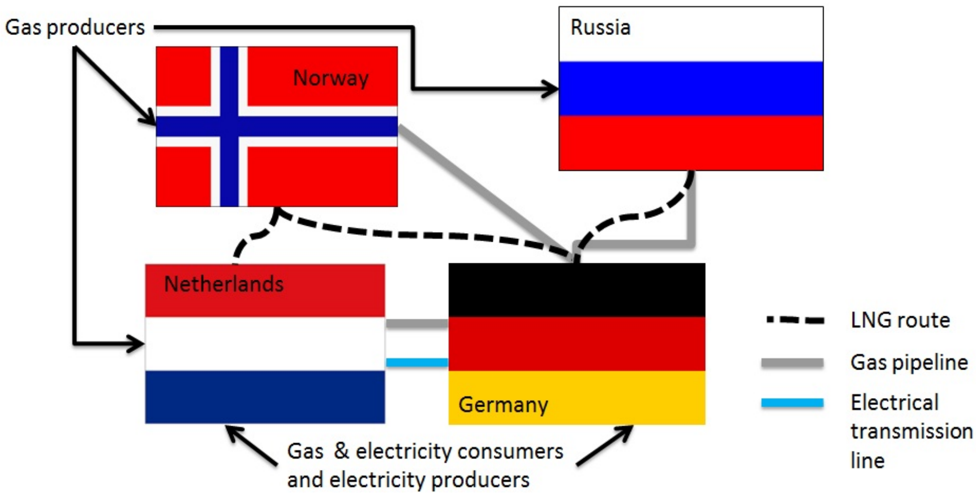

Figure 1: Visual representation of the 4-node network for the integrated Gas- and Electricity market model

The gas-only producing countries are connected to the Netherlands and Germany via pipelines and via LNG shipping routes. The marginal gas production costs in Norway are relatively high. However, due to Norway's relative proximity to the gas demanding countries the transportation costs remain limited. For Russia, the opposite holds. Germany and the Netherlands also trade natural gas via a single pipeline. In the Netherlands, the majority of the gas storage facilities are seasonal, while in Germany it is assumed that the majority of the gas storage facilities are peak storage facilities.

Regarding the electricity sector, Germany and the Netherlands trade electricity via a single transmission line. Electricity generation units in these countries consist of 25 technologies that differ with respect to their marginal costs.[3] Both seasonal and hourly variability of gas demand and variable renewable generation are represented by using hourly data for a representative week in each season; i.e., winter and fall (cold seasons) and spring and summer (warm seasons). Furthermore, electricity can be stored at a large scale both in Germany or the Netherlands by means of Compressed Air Energy Storage (CAES) or Hydro Pumped Storage that only differ according to their efficiency.

A scenario-based analysis has been performed in order to analyze the price-volume interactions between the G&E markets and the effect of certain drivers on such interaction. The scenario set-up is shown in Figure 2. The Current 2012 scenario represents an electricity market where I-RES shares in total generation are relatively low ($\approx 10\%$) as is the price for CO_2. In order to analyse the impact of increasing shares of I-RES, we assume that only the electricity market changes in the 2030 Baseline scenario whereas the gas market is unchanged. In the electricity market, I-RES shares in total generation increase (to $\approx 32\%$) while baseload capacities decreases compared to the Current 2012 scenario. Furthermore, no electricity storage is assumed in the Baseline 2030 scenario and the CO_2 price remains relatively low; thereby the competitiveness of NGFPPs with respect to coal fired power plants remains comparable to the Current 2012 scenario.

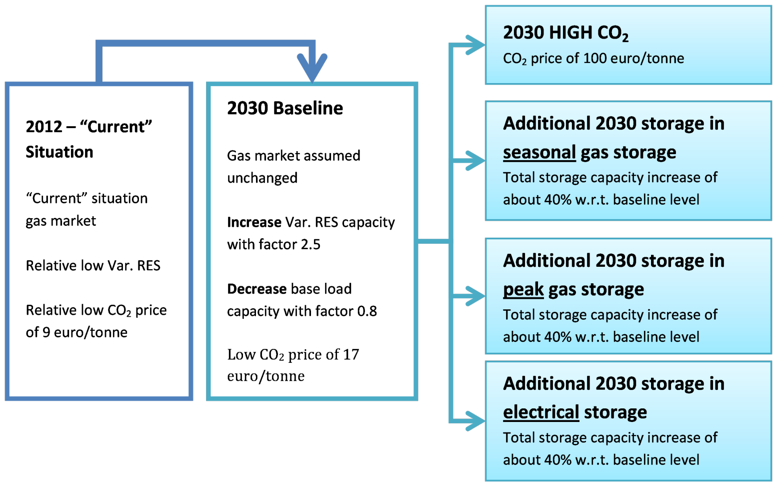

Figure 2: Scenario set-up and assumptions

We further consider four variants of the Baseline Scenario, where the High CO_2 scenario assumes a higher CO_2 price benefiting competitiveness of NGFPPs compared to coal fired power plants. In the remaining three variants, the effect of three types of energy storage technologies (i.e., seasonal gas storage, peak gas storage, electricity storage) is analyzed by comparing the outcomes of these scenarios to the Baseline 2030 scenario.

In Section 3.2 the results are discussed by means of statements, followed by an elaboration in Section 3.3 on the main lessons learned and the next steps to be taken. The analysis

3 Biomass- and waste standalone, hydro conventional, geothermal, wind, solar, nuclear, oil, coal PC, coal IGCC, lignite PC, gas CCGT, gas GT, gas CHP, and coke oven gas

provided in Section 3.2 shows what type of questions I-ELGAS is suitable for. Although the results cannot be generalized yet to the European system since they are derived from a limited four-node system, they give useful insights regarding the implications of some developments in the gas and electricity markets (i.e., increase in I-RES generation, CO_2 price, and energy storage investments) on the interactions between these markets.

3.2 Results

Increasing shares of I-RES results in a stronger correlation between gas demand from the power sector and I-RES generation

An important determinant for the level of the gas demand from the power sector is the residual demand in the electricity market which is equal to the hourly electricity demand minus the hourly production of I-RES (see Figure 3). Thus, the higher the generation from I-RES sources, the lower the residual demand and the lower the need for more expensive generation such as coal or gas. However, due to the variable characteristic of I-RES generation, flexible back-up capacity is still needed in times of low I-RES generation. In this respect, especially NGFPPs are suitable as back-up generation since these units are able to respond quickly to sudden changes in residual electricity demand. Hence, even though total gas demand from the power sector is decreasing in Baseline 2030 with increasing shares of I-RES generation compared to Current 2012 scenario, the correlation between the gas demand from the power sector and I-RES generation is becoming much stronger (see figure 4). Or in other words; the level of I-RES generation is becoming a more important determinant for the level of the gas demand from the power sector.[4].

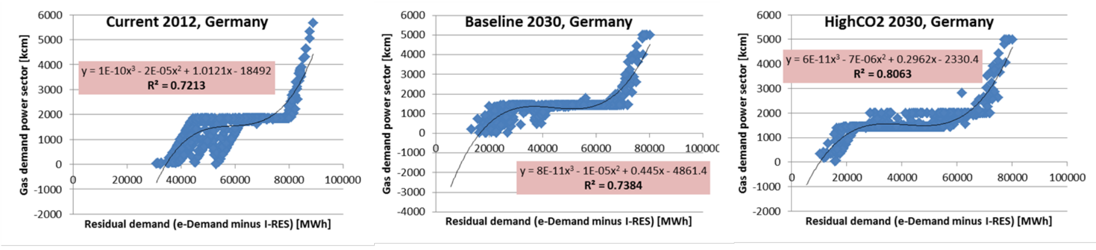

Figure 3: Regression of residual demand (e-demand minus I-RES generation) and the level of gas demand from power sector in Germany in the Current 2012 scenario, the Baseline 2030 scenario and the High CO_2 scenario.

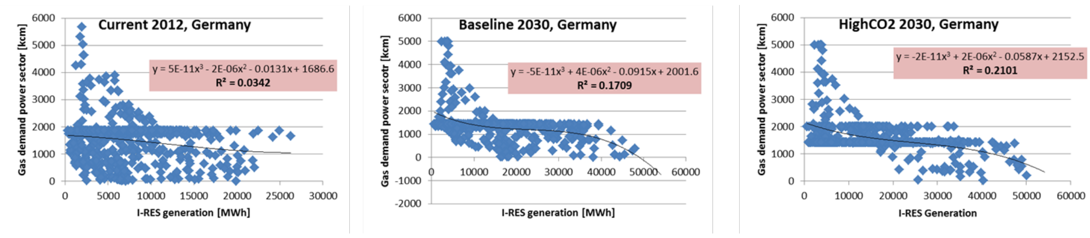

Figure 4: Regression of I-RES generation and the level of gas demand from power sector in the Current 2012 scenario, the Baseline 2030 scenario and the High CO2 scenario

Under a High CO_2 price (High CO_2 scenario), the competitiveness of NGFPPs increases mainly with respect to coal fired power plants. Due to the increased dispatch of NGFPPs,

4 In the Netherlands the same effect is seen; with increasing shares of I-RES, the level of I-RES generation is becoming a more important determinant for the level of gas demand from the power sector

the gas demand from the power sector increases resulting in I-RES levels becoming an even more important determinant for the hourly level of gas demand from the power sector (Figure 4).

Increasing shares of I-RES results in higher volatility of electricity prices and the effect on gas prices volatility is moderated by gas storage

As shown in Figure 5 the increasing shares of I-RES generation result in a significant increase in the volatility of e-prices. In the Baseline 2030 and High CO_2 scenario, e-prices in some hours are close to 0 €/MWh representing hours with high I-RES generation, while in other hours high price spikes are shown representing the hours with limited I-RES generation.[5] Under higher CO_2 prices the range of the marginal production costs of units is increasing. This implicitly leads to more volatile e-prices under different levels of I-RES generation.

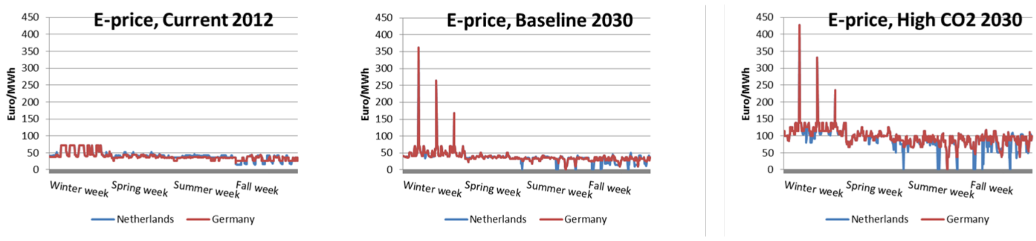

Figure 5: Volatility of hourly e-prices in the scenarios Current 2012, Baseline 2030 and High CO_2 2030

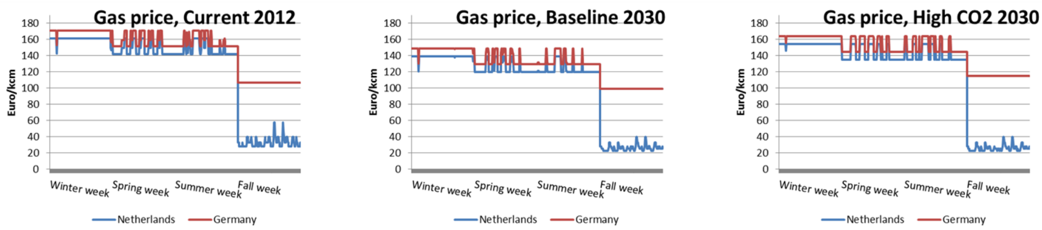

Figure 6: Volatility of gas prices in the scenarios Current 2012, Baseline 2030 and High CO_2 2030

In Figure 6 it is shown that the price volatility in the gas market does not increase. This is due to the fact that the gas market is already highly flexible; mainly due to gas storage but also due to demand elasticity in the residential sector and the industrial sector. Gas storage in general balances the extremes. Without gas storage, significant fluctuations in the hourly gas demand cannot be accommodated. The impact gas storage has on gas prices can be seen by comparing Figures 7 and 6 (Baseline 2030 scenario). In Figure 7, the Baseline 2030 scenario is run without any gas storage available in Germany and the Netherlands.

Peak storage can better provide flexibility to the electricity market compared to seasonal storage since the competitiveness of NGFPPs is increased, whereas electricity storage decreases the role of NGFPPs to accommodate flexibility

Gas storage optimizes the availability of gas throughout the year depending on the volatility of gas demand and prices. In this respect, seasonal storage is suitable to accommodate

5 In the Baseline 2030 and High CO_2 2030, demand is curtailed in hour 42 (winter week). Hence, the e-price reaches the level of the Value of Lost Load (VOLL) which is 10.000 euro/MWh. In order to show the volatility of prices in the graph, the maximum e-price of the non-curtailed hours is taken.

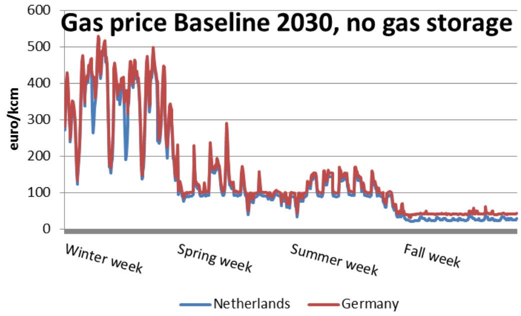

Figure 7: Volatility of gas prices in the Netherlands and Germany in Baseline 2030 without storage of gas

seasonal gas demand variability since it is restricted to inject in warm seasons and to extract in cold seasons. Compared to peak storage, the extraction and injection rates of seasonal storage are relatively low. Therefore, seasonal storage is less suitable to accommodate more extreme changes in the gas demand from one hour to the other. As

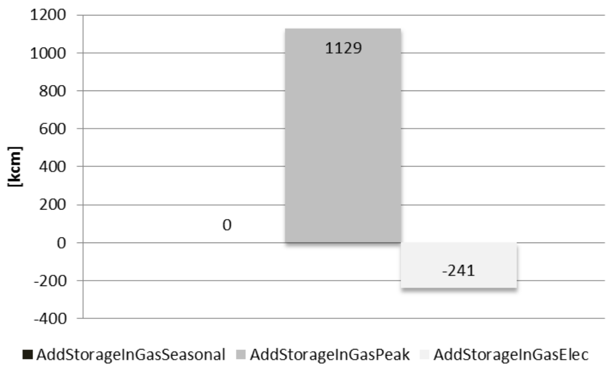

Figure 8: Difference in the level of gas demand from the power sector compared to Baseline 2030, sum of the Netherlands and Germany

illustrated in Figure 4, increasing shares of I-RES results in a stronger correlation between gas demand from the power sector and I-RES generation. Thereby, the variability of gas demand from the power sector is affected by I-RES generation that does not necessarily have a seasonal pattern and can be better accommodated with peak gas storage to optimally supply gas to the flexible NGFPPs. This is also illustrated in Figure 8. The additional seasonal storage capacity does not affect the gas demand from the power sector while the impact is significant with additional peak storage capacity. Increase in peak storage capacity results in more flexibility and competitiveness of NGFPPs, consequently increasing the gas demand from the power sector. With additional electricity storage, extreme events due to I-RES can be directly accommodated within the electricity market, reducing the need for flexible generation of NGFPPs and thus the gas demand from the power sector.

Peak gas storage and electrical storage can better accommodate the optimal use of increasing I-RES generation

When the generation of I-RES is higher than the demand for electricity or when the conventional generation units cannot fully ramp down with sudden increase in I-RES generation, I-RES generation is curtailed. On the contrary, electricity demand is curtailed when demand is higher than the available electricity production. In the Baseline 2030 scenario, 20.7 GWh of I-RES generation and 0.1 GWh of electricity demand is curtailed. Figure 9 shows that additional peak storage reduces I-RES curtailment to a certain extent since it indirectly helps to make optimal use of I-RES generation by increasing the flexibility of NGFPPs to accommodate variability in I-RES generation. Finally, as electricity storage directly provides flexibility in the electricity market, the reduction in the curtailment of both demand and I-RES generation is the most significant; in this case to a level of zero curtailment.

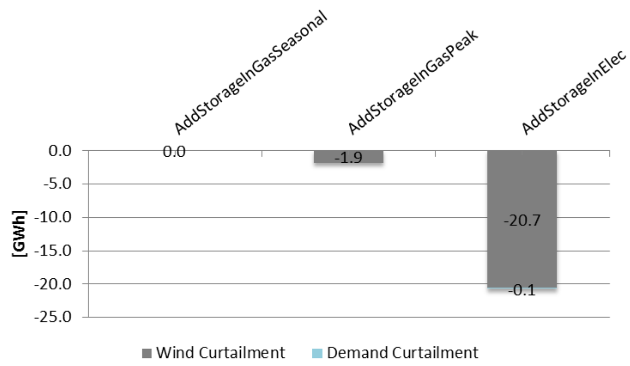

Figure 9: Difference in the level of curtailment compared to Baseline 2030, sum of the Netherlands and Germany

3.3 Conclusions and discussion

The electricity and gas markets are interdependent due to NGFPPs operating in both markets. This brings forward the necessity to analyse the two markets in an integrated fashion. In this study, an integrated G&E market model has been formulated, that is able to analyse short-term price and volume interactions in the G&E market on an hourly basis while also considering ramping rates, peak and seasonal gas storage, electricity storage, and I-RES variability. To our knowledge, none of the existing integrated G&E market models, that can model the short-term price and volume effects, differentiates the flexibility capabilities of different sources in both markets on this level of detail. Furthermore, we introduce a single optimization problem which finds the market equilibrium of the integrated G&E market assuming that the G&E markets are perfectly competitive. Thereby, computational time has been improved significantly allowing for solving large-scale systems including millions of variables and parameters instead of a few thousands.

The analysis presented in this study shows that the price-volume interaction between gas and electricity markets becomes stronger with increasing I-RES generation. Furthermore, the availability of flexible gas supply (i.e., peak gas storage) in the gas market becomes more important to determine competitiveness and future role of gas power plants in the electricity market. Although the conclusions cannot be generalized yet to the European system since the results are derived from a limited system with only a few nodes, our modelling approach allows for a more detailed analysis of energy systems on a large geographical and temporal scale. In the future, the model will be extended to a European scale including all hours in a year so that we can analyse important issues such as the future role of gas in the European electricity market under increasing shares of I-RES generation.

4

Nomenclature

Sets and indices

$c \in C$	Set of all countries
$o \in O \subset C$	Set of gas producing countries
$i, i' \in I \subset C$	Set of nodes for gas and electricity network
$J(i) \in I \subset C$	Set of nodes connected to node i
$ss \in SS$	Set of seasons: {Winter and Fall (cold season), Spring and Summer (warm season)}
$p \in P$	Set of periods (i.e., hours)
$P(ss) \in P$	Set of periods in season ss (i.e. hours)
$k \in K$	Set of arcs in pipeline distribution network
$m \in M$	Set of consumer markets in gas sector: {Ind, Res, Pow}
$f \in F$	Set of gas storage capacity types: {Seasonal, Peak}
$z, z' \in Z$	Set of gas production firms
$r \in R$	Set of electrical storage capacity types: {Hydro PS, CAES}
$h \in H$	Set of power units
$ngp \in NGP \subset H$	Set of natural gas fired power units
$oth \in OTH \subset H$	Set of all firms other than the natural gas fired power units.

Gas Market

Variables Gas Market

q^g_{zop}	Gas production by firm z located at o in period p [kcm]
s^g_{zip}	Total sales by firm z to consumers in node i in period p [kcm]
t^g_{zoip}	Pipeline transport by firm z from o to i in period p [kcm]
tl^g_{zoip}	LNG shipping transport by firm z from o to i in period p [kcm]
$flow^g_{kp}$	Cross-border pipeline-flow on arc k in period p [kcm]
x^g_{oip}	Inter-regional LNG transport from o to i in period p [kcm]
e^g_{ifp}	Gas extracted from storage type f by SSO at node i in period p [kcm]
inj^g_{ifp}	Gas injected into storage type f by SSO at node i in period p [kcm]
D^g_{mip}	Gas demand of sector m in node i in period p [kcm]
$price^g_{ip}$	Wholesale price of gas at node i in period p [€/kcm]

wt^g_{kp} Price of pipeline transport on arc k in period p [€/kcm]
wtl^g_{oip} Price of LNG shipment from o to i in period p [€/kcm]

Parameters Gas Market

N_p Number of days representing period p in a year
$CQ^g(q^g_{zop})$ Total gas production cost of firm z in production node o in period p [€]
$CS^g(inj^g_{ifp})$ Total operational cost of storage type f in node i in period p [€]
$CX^g(x^g_{oip})$ Total cost of operating the transmission of LNG from node o to i in period p [€]
$CZ^g(flow^g_{kp})$ Total cost to transporting gas via pipeline k in period p [€]
A^g_{mip} Intercept of linear gas demand function
B^g_{mip} Slope of linear gas demand function
$CONVF$ The conversion factor to convert €/kcm to €/MWh = 0.1017825
GTC^g_{oik} Gas transmission capability: 0 or 1 parameter denoting if transmission can take place from o to i through pipeline k.
LTC^g_{oi} LNG transport capability: 0-1 parameter denoting if LNG can be shipped from o to i
Q^g_{zo} Annual production capacity of firm z at o [kcm]
SC^g_{if} Annual working gas capacity of storage type f at node i [kcm] (corrected for share of cushion gas)
SER^g_{if} Extraction rate of storage type f at node i [kcm/hour]
SIR^g_{if} Injection rate of storage type f at node i [kcm/hour]
TG^g_{kp} Capacity of gas pipeline k in period p [kcm]
TLG^{out}_{zop} LNG liquefaction capacity of producer z at o in period p [kcm]
TLG^{in}_{ip} LNG regasification capacity at i in period p [kcm]

Electricity Market

Variables Electricity Market

g^e_{ihp} Production of electricity by unit h at node i in period p [MW]
ENS^e_{ip} Energy Not Served (curtailed demand) at node i in period p [MW]
$flow^e_{ii'p}$ Electricity flow on interconnection from node i to node i' in period p [MW]
y^e_{ip} Net electricity imports/exports at node i in period p [MW]
β^e_{ihp} Scarcity rent for power producer h at node i in period p [€/MW]
$price^e_{ip}$ Wholesale price of electricity for node i in period p [€/MWh]
ds^e_{irp} Level of electrical discharge at node i of storage type r in period p [MW]
ch^e_{irp} Level of electrical charge at node i of storage type r in period p [MW]
SOL^e_{irp} Energy storage level at node i of storage type r in period p [MW]

Parameters Electricity Market

D^e_{ip} Electricity demand at node i in period p [MW]
$VOLL^e$ Value Of Lost Electricity Load [10.000 €/MWh]
$PCO2$ Cost of CO2 emission [€/tonne]
Θ_h Emission factor of unit h [tonne/MWh]
FP_{ihp} Fuel price of unit h at node i in period p [Euro/MWh]
$T^e_{ii'}$ Import/export transmission capacity provided by TSO between node i and i' [MW]
AF^e_{ih} Availability factor of unit h in node i

$C^e(g^e_{ihp})$ Total operational and maintenance cost of unit h located at node i in period p [€]
$CR^e(ch^e_{irp})$ Total operational cost of electrical storage type r located at node i in period p [€]
OM^e_{ih} Marginal variable operating maintenance cost of unit h at node i [€/MWh]
η^e_{ih} Electrical efficiency of unit h at node i
G^e_{hi} Capacity of unit h in node i [MW]
RR^e_{ih} Maximum ramp rate of unit h in node i [MW/hour]
PS^e_{ir} Electrical storage capacity at node i of storage type r [MW]
SC^e_{irp} Electrical storage capacity at node i of storage type r depending on the number of storing hours [MWh]
ISC^e_{r0} Initial energy level of storage type r at node i at hour 0, assumed 50 percent of total capacity [MWh]
eff^r Efficiency of electrical storage facility depending on the storage type r [1:=100 percent]

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