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Abstract

Electricity markets with high installed capacities of Variable Renewable Energy Sources (VRES) experience periods of supply and demand mismatch, resulting in near-zero and even negative prices, or energy spilling due to surplus. The participation of emerging Power-to-X solutions in a sector coupling paradigm, such as Power-to-Gas (PTG), has been envisioned to provide a source of demand flexibility to the power sector and decarbonize the gas sector. We advance a long-run equilibrium model to study the PTG investment decision from the point of view of a perfectly competitive electricity and gas system where each sector's market is cleared separately but coupled by PTG. Under scenarios combining PTG technology costs and electricity RES targets, we study whether or not there is a convergence in the optimal deployment of PTG capacity and what is the welfare distribution across both sectors. We observe that PTG can play an important price-setting role in the electricity market, but PTG revenues from arbitrage opportunities erodes as more PTG capacity is installed. We find that the electricity and gas sector have aligned incentives to cooperate around PTG, and instead find an issue of misaligned incentives related to the PTG actor. Although not the focus of our analysis, in some scenarios we find that the welfare optimal PTG capacity results in a loss for the PTG actor, which reveals some intuition that subsidizing PTG can make sense to reduce the cost of RES subsidies. A sensitivity analysis is conducted to contextualize these findings for system specificities.

Keywords

Sector coupling, power-to-gas, renewable energy sources, mixed complementarity problem.

1. Introduction[*]

Electricity markets with high installed capacities of Variable Renewable Energy Sources (VRES) experience periods of supply and demand mismatch, resulting in near-zero and even negative prices, or energy spilling due to surplus. Ambitious Renewable Energy Sources (RES) targets and Greenhouse Gas (GHG) emissions reduction objectives in the EU could aggravate this problem further. The participation of emerging Power-to-X solutions in a sector coupling paradigm, such as Power-to-Gas (PTG), have been envisioned to provide a source of demand flexibility to the power sector and decarbonize the gas sector. For many reasons, the analysis of sector coupling strategies are gaining increasing attention from policy-makers.

The European Commission states that a sector coupling approach to energy technologies and infrastructure allows for the optimal use of available resources, the avoidance of stranded assets and the best provision of information for investment decisions (European Commission, 2018). In a report commissioned by European Parliament, the authors state that the concept of sector coupling has broadened to now include supply-side integration which focuses on the integration of the power and gas sectors through technologies such as PTG (European Parliament and Trinomics B.V., 2018). In another report commissioned by the European Commission, the authors state that according to gas Transmission System Operators (TSOs), an integrated energy infrastructure building on the existing electricity and gas systems would in principle be more efficient, resilient, sustainable and less expensive than an all-electric energy infrastructure (European Commission and Trinomics B.V., 2018). Finally, in a report commissioned by the Council for European Energy Regulators (CEER), the authors state that PTG can be used to absorb and store electricity by converting it into hydrogen in case of surplus renewable electricity, and later it can be used as a transport fuel, converted back to electricity or injected into the natural gas network (CEER and KEMA Consulting GmbH, 2018).

A coherent sector coupling strategy is increasingly demanded by stakeholders across energy sector value chains. In a report commissioned by a consortium of gas TSOs, the authors emphasize the reliability and flexibility value which gas grids ensure, and put forward that the infrastructure can be used to transport renewable methane and hydrogen to meet ambitious climate objectives (Gas for Climate and Navigant Consulting, 2019). According to the International Renewable Energy Agency (IRENA), hydrogen from renewables has the technical potential to channel large amounts of renewable electricity to sectors for which decarbonization is otherwise difficult (IRENA, 2018). Business case analyses for various PTG market applications are carried out by ENEA Consulting (2016) and DNV GL (2018). They find that significant cost reductions in electrolyzer technology, access to inexpensive power and greater penetrations of VRES are identified as critical factors in this regard. Market failures and other barriers persist for hydrogen adoption in industry and are described in more detail by the World Energy Council (2018).

Research conducted by academics has focused on the economic potential of PTG in different applied settings. A case study on linking electricity and gas networks to produce hydrogen via PTG in a city in Japan was investigated using a simulation model. The authors found that the required optimal electrolyzer size increases with increasing the PV fraction ratio of combined renewable production (Li et al., 2019). Another case study on the production of hydrogen via PTG is conducted for France (Tlili et al., 2019). The authors find that the potential of hydrogen production in France using electricity

[*] We would like to thank the concurrent session participants of the 42nd International Association for Energy Economics conference held at HEC Montreal. Additionally, we extend thanks to the participants from the 2nd International Conference on the Economics of Natural Gas held at Paris-Dauphine University in Paris. The PhD research of Martin Roach is supported by the research partnership between Vlerick Business School and Fluxys. We would like to thank Thierry Deschuyteneer and Rudy Van Beurden from Fluxys for their valuable feedback. Lastly, thank you to Tim Schittekatte and Florence School of Regulation team for their help in revising and formatting this working paper.

surplus is overestimated unless you take into account interconnections which can impact flexibility needs of the electric system. PTG is studied from the point of view of portfolio effects of holding different generation and PTG technologies using a stochastic Mixed Complementarity Problem (MCP) in Lynch et al. (2018), but they assume a fixed gas price to represent the gas sector. They find that the participation of PTG has the potential to make other technologies more or less profitable. The role of PTG in a sector coupling – electricity, gas and CO2 – framework is modeled by Vandewalle et al. (2015). They observe PTG setting the electricity market price in a 100% VRES electricity system and flexibility requirements in the gas system increasing due to PTG's participation. A review of academic studies for a basic understanding of electrolysis technologies used in PTG can be found in Buttler and Spliethoff (2018) and for the storage role of PTG in Blanco and Faaij (2018).

However, with few exceptions, the previously cited reports and academic studies overlook the potential misalignment in incentives to install PTG. If the support for PTG from the electricity and gas sector diverges due to the impact PTG's presence may have on the redistribution of welfare across sectors or market players, then investments in PTG may never materialize. The aim of this paper is to study the PTG investment decision from the point of view of a perfectly competitive electricity and gas system where each sector's market is cleared separately but coupled by PTG. We study whether or not there is a convergence in the optimal deployment of PTG capacity and what the welfare distribution is across both sectors.

MCPs have been advanced for a large range of problems found in the energy sector and have certain advantages inherent in combining the optimization problems of multiple agents and in constraining primal and dual variables together, which has motivated this chosen method (Gabriel et al., 2013). Similar alignment in incentives has been studied for transmission investment in interconnectors between countries to cost-effectively integrate RES using a MCP formulation, but the authors only considered an electricity system (Saguan and Meeus, 2014). MCP formulations have also been used to model wholesale gas markets while incorporating gas demand from the electric power sector, but the direct participation of sector coupling assets such as PTG is absent (del Valle et al., 2017). Inspired by the previous sector-specific MCP models, we propose a stylized long term equilibrium model which is built up using a MCP formulation. We study the welfare distribution and price effects at sector optimal capacities of PTG to know if we can expect a misalignment in incentives between the electricity and gas sector at the long-run equilibrium.

This paper is organized in two main sections. Section 2 describes how we build up the model and the underlying assumptions. Section 3 details the results from a numerical example. Lastly, our key findings are summarized in the conclusion.

2. Methodology

First of all, our modelling approach is described in Section 2.1. Second of all, the mathematical formulation is provided in Section 2.2.

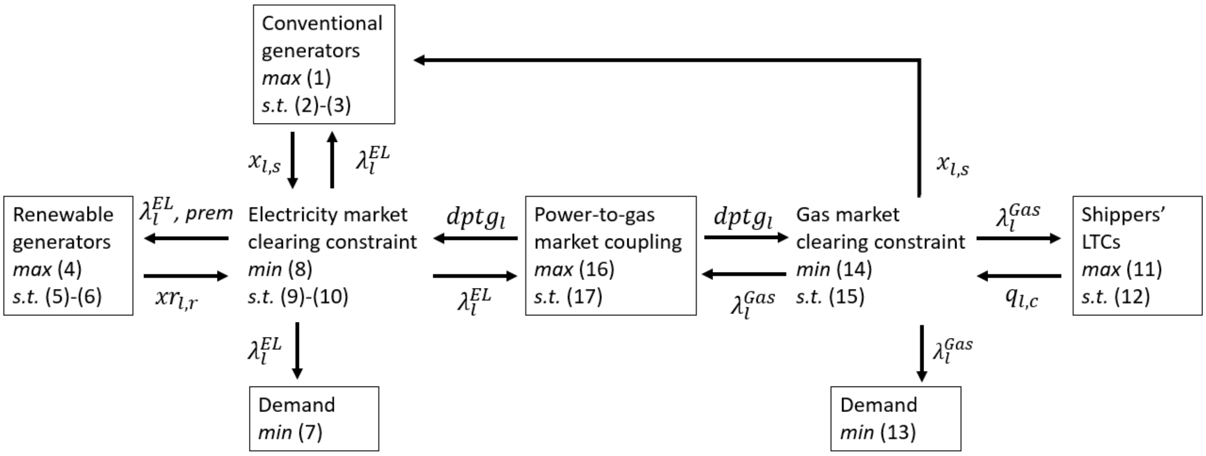
2.1. Modelling Approach

Our stylized model simulates the long-run equilibrium of an integrated wholesale electricity and gas market which have sector specific market clearing constraints coupled through the participation of an exogenously given installed capacity of PTG. The electricity and gas market are perfectly competitive. The model is depicted schematically in

Figure 1. Multiple iterations are executed in the model, for each iteration investment in PTG capacity increases by 50 MW increments, reflecting the lumpiness of such investments, and the market clearing conditions lead to an equilibrium in the electricity and gas market simultaneously. In each iteration, the

operation of the PTG assets responds to prices in both markets under a short-run profit constraint and is constrained by its installed capacity.

Figure 1: Schematic overview of market coupling with PTG, including references to the optimization problems (1)-(16) of the agents (cf. Section 2.2)



For each model run, we analyze the evolution of sector welfare and total welfare as PTG capacity is increased in order to identify sector-specific equilibrium and system optimal points. The model is designed for an energy system that has l periods, where each period is T_l hours and $\sum_{l \in L}(T_l) = 8760\ hours$. The formulation uses representative hours, so the market clearing prices and quantities solved at a per period resolution are extended to all hours in T_l .

2.2. Mathematical formulation

In this section, the decision-making problems of all agents are presented. The dual variables associated with each constraint are given in between parentheses.

2.2.1. Electricity Market

Conventional generators

The decision variables of each conventional generation technology s are its installed capacity g_s and its hourly generation $x_{l,s}$. The optimization problem of each conventional generator is defined as (1)-(3):

Maximize

$$\sum_{l \in L}((\lambda_l^{EL} - VC_s - \lambda_l^{Gas}) \bullet x_{l,s} \bullet T_l) - CC_s \bullet g_s \tag{1}$$

Subject to

$$0 \leq x_{l,s} \leq g_s ,\ \forall l \in L, \forall s \in S \ \ (\rho_{l,s}^{-}, \rho_{l,s}^{+}) \tag{2}$$

$$0 \leq g_s ,\ \forall s \in S\ (\xi_s) \tag{3}$$

Each generator maximizes its profit, subtracting its operational and investment costs from its market revenues. For each generation technology type s, variables costs are defined as VC_s and annualized investment costs as CC_s. Since the conventional generators later introduced are Gas Fired Power Plants (GFPP), the price of gas λ_l^{Gas} is also included as a variable cost component in the optimization problem. Through constraint (2), production in a given period is constrained by the installed generation capacity in all periods. We assume that conventional generation is 100% available over the year. When a generation technology type s is producing at its maximum, $\rho_{l,s}^{+} \geq 0$, the generator uses the dual variable to bid into the electricity market. In this way, the generator acquires scarcity rents which contribute to recovering its investment costs.

Renewable generators

The decision variables of each renewable generation technology r are its installed capacity gr_r and its hourly generation $xr_{l,r}$. The optimization problem of each renewable generator is defined as (4)-(6):

Maximize

$$\sum_{l \in L} ((\lambda_l^{EL} - \mathrm{VCR_r}) \bullet xr_{l,r} \bullet \mathrm{T_l}) - \mathrm{CC_r} \bullet gr_r + \sum_{l \in L} (gr_r \bullet prem \bullet \mathrm{T_l}) \tag{4}$$

Subject to

$$0 \leq xr_{l,r} \leq gr_r \bullet \mathrm{AVA_{l,r}}, \ \forall l \in L, \forall r \in r \ \ (\mu_{l,r}^{-}, \mu_{l,r}^{+}) \tag{5}$$

$$0 \leq gr_r, \ \forall r \in r \ (\pi_r) \tag{6}$$

Renewable generators are confronted with a similar profit maximization as conventional generators, subtracting their operational and investment costs from their market revenues. However, an additional revenue stream is received from a subsidy scheme for renewables which takes the form of an hourly capacity-based premium. Variable costs are defined as $\mathrm{VCR_r}$ and annualized investment costs $\mathrm{CCR_r}$. Through constraint (5), production is constrained by the installed generation capacity and its availability factor $gr_r \bullet \mathrm{AVA_{l,r}}$ in each period. The renewable generator spills its production whenever it cannot be absorbed by demand. Spillage is not an active decision variable in our model, but can be calculated at equilibrium in each period as: spillage = $\sum_{r \in R} (gr_r \bullet \mathrm{AVA_{l,r}}) - xr_{l,r}$

Electricity Consumers

Electricity consumers are inelastic and have no decision variables in their objective to minimize costs (7). They are price takers in the electricity market and carry the total subsidy costs associated with the renewable premium $prem$ to support RES generators.

Minimize

$$\sum_{l \in L} ((\lambda_l^{EL} \bullet \mathrm{D_l} \bullet \mathrm{T_l}) - (prem \bullet gr_r \bullet \mathrm{T_l})) \tag{7}$$

Electricity Market Clearing Constraint

The electricity market clearing constraint (8) endogenously determines the market price λ_l^{EL} for each period with the objective of minimizing total energy costs for the electricity sector. The renewable target constraint (9) requires that a percentage of gross electricity consumption must be met by non-spilled RES electricity production calculated on an annual basis. An exogenous RES target is based on consumption of inelastic consumers while any incremental demand from PTG is automatically served by RES that is spilled. The dual variable of this constraint re-enters the renewable generator optimisation problem to form an hourly capacity based premium. The non-negativity constraint (10) ensures a positive price.

Minimize

$$\sum_{l \in L} ((\sum_{r \in R} xr_{l,r}) + (\sum_{s \in S} x_{l,s}) - \mathrm{D_l} - dptg_l) \bullet \mathrm{T_l} \bullet \lambda_l^{EL}) \tag{8}$$

Subject to (9)

$$\sum_{l\in L}\sum_{r\in R} xr_r \bullet T_l - \left(\text{RENTARGET} \bullet \sum_{l\in L}(\mathrm{D_l} \bullet \mathrm{T_l})\right) - \sum_{l\in L}(dptg_{\mathrm{l}} \bullet \mathrm{T_l}) \geq 0 \ \ (prem)$$

$$\lambda_l^{EL} \geq 0 \ \forall l \in L \ (\eta_l^{EL}) \tag{10}$$

2.2.2. Gas Market

Shippers and Long Term Contracts

A shipper may have a portfolio of Long Term Contracts (LTCs) in which price formulas may differ due to execution date, indices, flexibility, among others, therefore a simplified procurement cost function was assumed, which has also been similarly used in del Valle et al. (2017). Given we do not attempt to model strategic behavior of gas shippers, we represent the perfectly competitive outcome of multiple shippers as one shipper with one procurement cost function. This shipper's procurement cost function is represented by an affine function with intercept LTCint and slope LTCslope. The objective of each shipper is to maximize its profit, which is equal to revenues from sales on the gas market minus its total procurement costs.

Maximize

$$\sum_{l\in L}\left(\left(\text{LTCint} + \text{LTCslope} \bullet q_{l,c}\right) - \lambda_l^{Gas}\right) \bullet q_{l,c} \tag{11}$$

Subject to

$$q_{l,c} \geq 0\,, \qquad \forall l \in L, \forall c \in C \ \left(\mu_{l,c}\right) \tag{12}$$

Conventional Demand Gas

Gas consumers have an inelastic demand $\mathrm{DG_l}$ and have the objective to minimize costs (13) but they do not have any decision variables. Gas consumers are price-takers, but they do not contribute to the subsidy scheme to support renewable electricity generators.

Minimize

$$\sum_{l\in L}\lambda_l^{Gas} \bullet \ \mathrm{DG_l} \bullet \mathrm{T_l} \tag{13}$$

Gas Market Clearing Constraint

The gas market clearing constraint endogenously determines the market price λ_l^{Gas} with the objective of minimizing total energy costs for the gas sector. The non-negativity constraint (15) ensures a positive price.

Minimize

$$\sum_{l\in L}\left(\left(\sum_{c\in C}(q_{l,c}) - \mathrm{DG_l} - \sum_{s\in S}\left(x_{l,s}\right) + (dptg_l \bullet \text{CONV})\right) \bullet \mathrm{T_l} \ \bullet \lambda_l^{Gas}\right) \tag{14}$$

Subject to

$$\lambda_l^{Gas} \geq 0 \ \forall l \in L \ (\eta_l^{Gas}) \tag{15}$$

2.2.3. Power-to-gas

Market Coupling

PTG arbitrages perfectly between the electricity and gas market while taking into account the exogenous conversion efficiency CONV and price in both markets λ_l^{EL} and λ_l^{GAS}. As a load in the electricity market and a supply source in the gas market, PTG operations $dptg_l$ is the two-sided decision variable linking the markets together. The PTG's market coupling role solves the optimization problem (16)-(17). Constraint (16) limits electricity consumption of PTG $dptg_l$ to the installed capacity PTGCAP.

Maximize

$$\sum_{l\in L}((dptg_l \bullet \mathrm{CONV} \bullet \lambda_l^{GAS}) - (dptg_l \bullet \lambda_l^{EL})) \bullet \mathrm{T_l}) - (\mathrm{PTGCAP} \bullet \mathrm{PTGINVC}) \tag{16}$$

Subject to

$$0 \leq dptg_l \leq \mathrm{PTGCAP} \quad \forall l \in L \;\; (\delta_l^-, \delta_l^+) \tag{17}$$

3. Results

Detailed in the following section, we advance a stylized numerical example in order to analyse the welfare and price effects of electricity and gas market coupling with PTG.

3.1. Numerical Example

3.1.1. Electricity Market

The stylized electricity market is composed of two sets of generation technologies: two conventional generators – Open Cycle Gas Turbine and Combined Cycle Gas Turbine (OCGT & CCGT) – and one renewable generator (i.e. wind). Data assumptions for these generation technologies are based on a study conducted by the Belgian electricity TSO, Elia (2017). Each generation technology has a representative new-built capacity costs and variable costs (excluding fuel, emissions and personnel costs). These Gas Fired Power Plants' (GFPP) variable costs are higher for OCGT than for CCGT which accounts for differences in conversion efficiencies. Both GFPP face the same fuel costs due to purchases on the gas market, which when summed together are the total variable costs in operations. The annualized investment costs were determined based on a 20 year economic lifetime, weighted average cost of capital of 6% and assumed fixed operation and maintenance costs for each technology. Lastly, annual availability factors were assigned, 30% of installed capacity for RES and 100% for conventional. A summary of the data assumptions appears in Table 1.

Table 1: Generators data assumptions

Technology	Variable costs €/MWh: $\mathrm{VC_s}$& $\mathrm{VCR_r}$	Annualized investment costs €\MW.year: $\mathrm{CC_s}$&$\mathrm{CC_r}$	Availability %
CCGT	2	94 500	100%
OCGT	11	64 500	100%
RES – i.e. wind	0	159 000	30%

The demand of inelastic electricity consumers is represented by a Load Duration Curve (LDC) $\mathrm{D_l} = 22000\ MW - 1.37\ hours$ which is taken from Joskow (2006). This LDC is subdivided into 10 periods of 876 hours each. Therefore, the instantaneous balance between supply and demand is not incorporated, nor are ramping or other technical generation constraints.

3.1.2. Gas Market

The stylized gas market is comprised of two sets of gas supplies: the renewable gas from hydrogen injected by PTG and conventional natural gas accessed via LTCs by shippers. Both are considered perfectly substitutable and measured in €/MWh. Here we assume no alternative gas supplies from LNG or other renewable gases to the gas market. We represent the outcome of perfectly competitive shippers as a single LTC procurement cost function. We take the assumed gas price of 18 €/MWh as in Lynch et al. (2018) for the LTC intercept and add a LTC slope as in del Valle et al. (2017) for the upward sloping LTC procurement cost function of a shipper.

Intercept of Long Term Contract €	Slope of Long Term Contract €/GWh
18	.25

The electricity sector's GFPP and inelastic gas consumers are the two sources of demand participating in the gas market. The GFPP are elastic in responding to gas prices and are therefore another linking asset participating in both the electricity and gas market simultaneously. The inelastic gas consumers have equal demand in each period and this demand was derived in such a way that the inelastic electricity and gas demand are of equal size. The inelastic gas demand per period was determined by taking the annual inelastic electricity demand in MWh from the LDC and dividing it by the number of hours. Therefore, this gas demand is uncorrelated with the electricity LDC. This is also a shortcut in the model because gas storage is not included nor are correlations between electricity and gas estimated.

3.1.3. Power-to-gas

The primary driver of PTG investment costs is the technology costs of electrolyzers. A recent report by Agora Verkehrswende et al. (2018) provide a summary of current and future electrolyzer costs which have been estimated in various studies. We assume a conversion efficiency of 80% for electrolysis in line with this report forecasted for future low temperature electrolysis. Given the costs of the PTG installation will evolve into the future, PTG investment cost is a parameter that we vary with the following range of: 0, 200, 500 and 1000 in €/kW. These investment costs are annualized based on a 25 year economic life, 6% WACC and 2% of capital costs for fixed O&M, taken from Enea Consulting (2016).

3.1.4. Renewable energy targets discussion

Following a revision of the Renewable Energy Directive in the Clean Energy for all Europeans Package in 2018, the EU has set a binding renewable energy target of 32% of energy from renewable sources in the Union's gross final consumption of energy by 2030 (European Union, 2018). Gross final consumption of energy includes energy needs for industry, transport, heat and electricity. According to the accompanying Regulation on the Governance of the Energy Union and Climate Action, how each Member State (MS) will contribute to the achievement of this goal, alongside additional objectives for energy efficiency improvements and greenhouse gas emissions reductions, will be further detailed in its National Energy and Climate Plans for the 2021-2030 period. Each MS's 2020 renewable energy targets will be the bare minimum that must be met. Many MSs have pursued RES targets via the deployment of renewables in the electricity sector, and we utilise an electricity RES target as a given for our stylized setting. Ambitious and binding RES targets send a clear market signal and incentives for RES investment, and is included in our model for this reason.

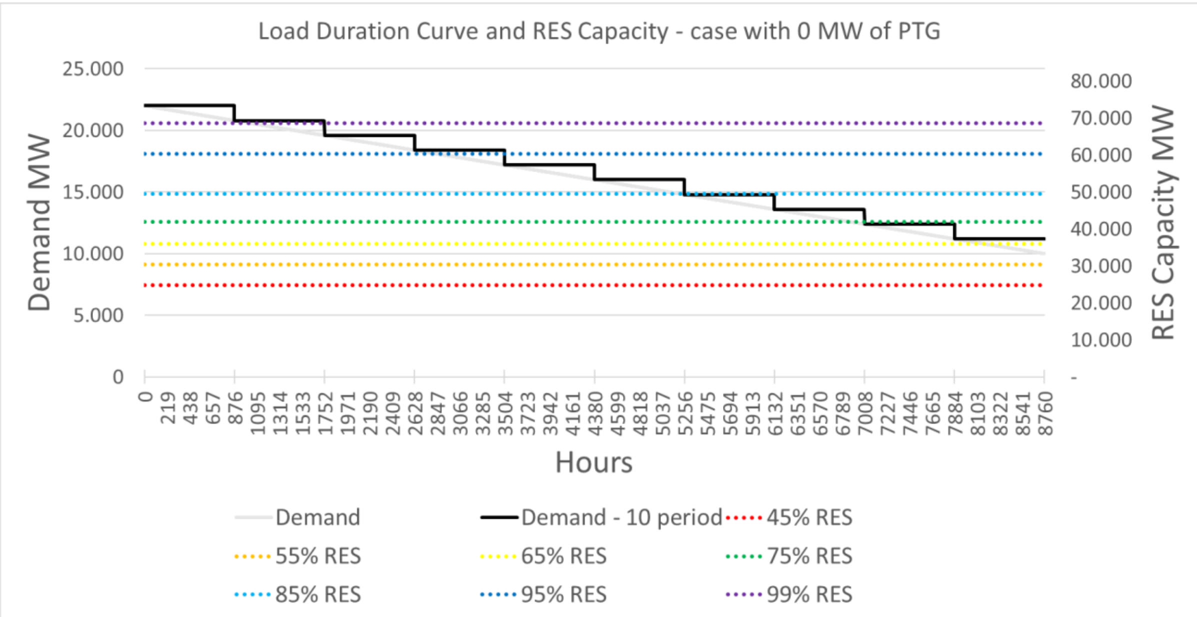
3.2. Results

First, a baseline in which the long-run market equilibrium when an RES target is set and no PTG is installed is explained. The baseline is the reference point to which the later welfare analysis will be compared. Second, the price effects of PTG on the electricity and gas markets will be discussed. Third, the impacts of PTG on sector and total welfare will be summarized with an accompanying sensitivity analysis. Fourth, limitations of our model and approach are discussed.

3.2.1. Baseline - case without power-to-gas

The case of no PTG provides a baseline for later making a comparison of the impact of PTG on electricity and gas markets. In this case, the electricity market has only one source of demand defined by the inelastic LDC over 10 periods and the optimal mix of generation technologies is selected such that the exogenous RES target set is satisfied. In requiring a specified percentage of energy consumed to be supplied by renewables, the RES target drives a minimum amount of renewable capacity to be installed, as depicted for multiple RES targets in Figure 2. The RES capacity required to satisfy a given RES target must take into account the 30% annual RES availability factor to obtain firm capacity. Without a RES target, no RES would be installed because it is not the least cost resource participating in the market.

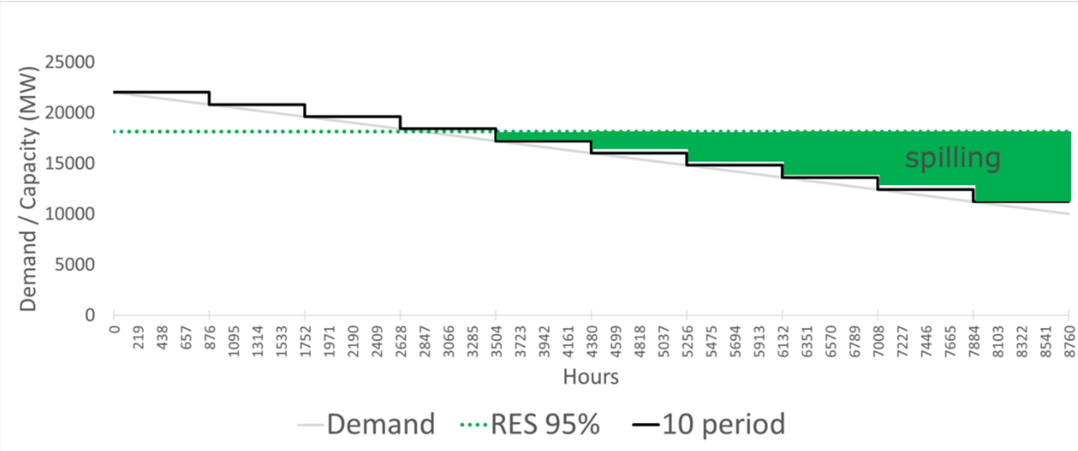
Figure 2: Impact of RES Targets on RES Capacity Installed



Spillage only occurs at RES targets greater than 65% and the amount of spillage is the area underneath the RES target line and above the LDC. For each incremental 5% RES target above 65%, the marginal quantity of RES capacity installed increases due to spillage. RES Capacity investment decisions are strongly dependent on the RES target set. Given an RES target of 95%, the RES capacity required is 60,415 MW and this results in a firm capacity of 18,125 MW.

As depicted in Figure 3, for this scenario energy spillage occurs in low demand periods. The remaining generation capacity is met by the least cost GFPP technology, which will produce in peak demand periods.

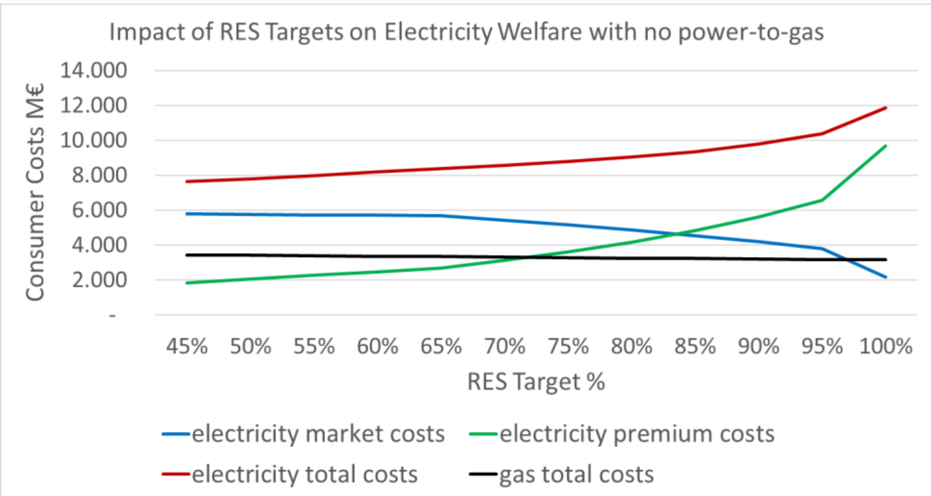
Figure 3: Baseline in Electricity Market for 95% RES Target



The electricity market price is cleared for each period and extended to all 876 hours in that period. When spilling of RES occurs in a period, the market clearing price is 0 €/MWh. Otherwise, it is set either by the conventional generator's variable costs according to the merit order or by scarcity pricing in peak periods for the recovery of fixed investment costs based on the dual variable of the generator's capacity constraint. Given RES is not the least cost technology, the capacity-based RES premium is endogenously determined to make-up for insufficient electricity market revenues such that RES generators recover investment costs and meet its zero profit condition.

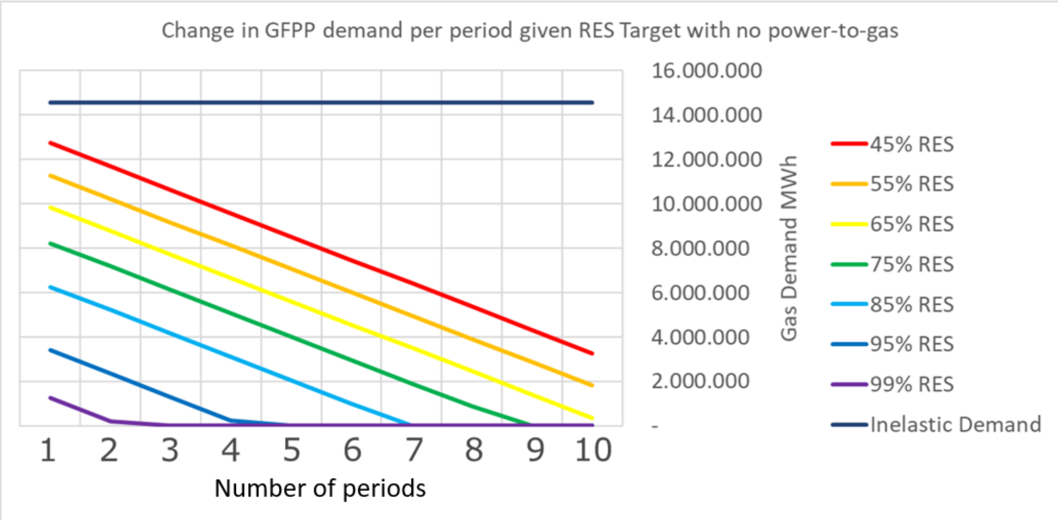
Electricity consumers benefit when electricity market prices are 0 €/MWh when RES place downward pressure on prices. However, at the same time, the out-of-market capacity-based premium is a subsidy costs borne by electricity consumers to support higher RES targets. As illustrated in Figure 4, higher RES targets increase total costs for electricity consumers in the case with no PTG because of significant subsidies for RES generators.

Figure 4: Impact of RES targets on Sector Welfare with no PTG



In the same instance of no PTG, the gas market has only one source of supply being the shipper's LTC to satisfy both the demand of inelastic gas consumers and GFPPs. The impact of RES targets on the gas market takes place through the participation of GFPP. When GFPP capacity is substituted in favor of RES capacity due to higher RES targets, this directly affects the quantity of gas demanded from the gas market, as depicted in Figure 5. This reduction in demand lowers procurement cost for the shipper and translates into lower gas prices which end up benefiting inelastic gas consumers.

Figure 5: Impact of RES Targets on Gas Market Demand



3.2.2. Case with power-to-gas

3.2.2.1. Price Effects

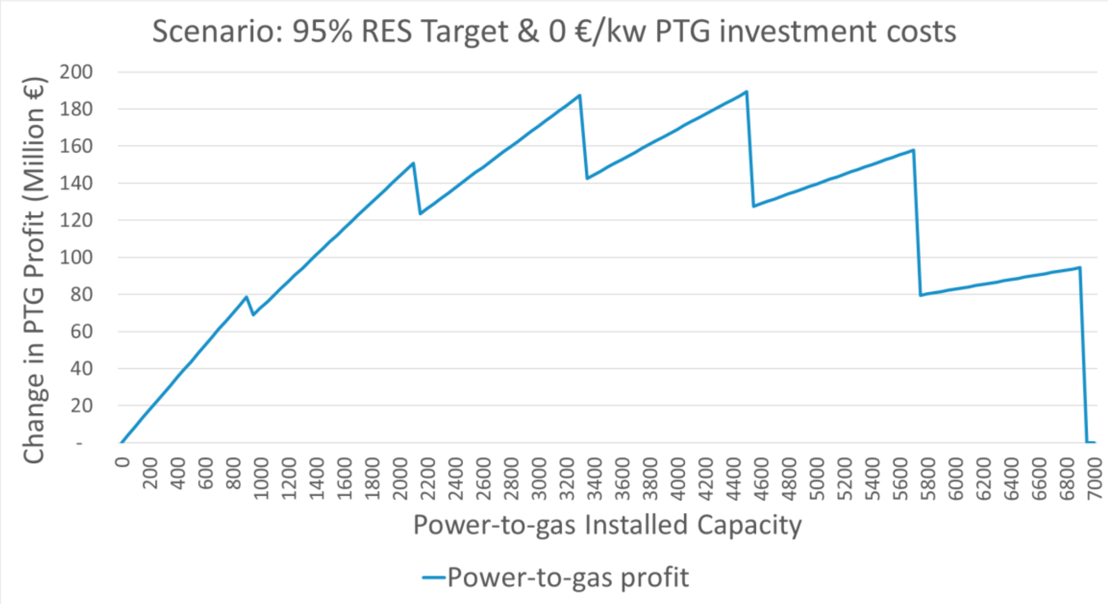
When PTG is introduced into the model, its participation affects price formation in the electricity market through its arbitrage objective as a market coupling agent. Here the price effect induced by PTG participating in the electricity market is described in detail. When renewables are spilled in a given period, the electricity market price is 0 €/MWh. In a given period, if you do not have enough PTG capacity installed to evacuate all of this spillage, the price remains 0 €/MWh. On the other hand, similar to what has been observed in Lynch et al. (2018) & Vandewalle et al. (2015), once the spillage is absorbed in a given period, the electricity price is set by the perfectly competitive participation of PTG based on its short term zero profit conditions. This condition ignores sunk investment costs, meaning PTG operates as long as the electricity it consumes and subsequently converts into hydrogen can be sold for at least the price on the gas market. This inter-fuel arbitrage can be reached through reorganizing PTG's short term zero profit condition:

$$\left(ElectPrice_l * \frac{1}{CONV}\right) \geq GasPrice_l \; \forall \; l$$

For example, if the gas market price is 20 €/MWh, then at a 80% conversion efficiency, the competitive price set by PTG in the electricity market is 16 €/MWh. However, it is possible that there is insufficient PTG capacity to evacuate all of the renewable spillage in all periods. This leads to PTG setting the electricity market clearing price only in some periods and others remain at 0 €/MWh.

Figure 6 illustrates a scenario in which a RES target of 95% leads to spillage in multiple periods and therefore an incentive for PTG to be installed to absorb it. As more PTG capacity is installed, the electricity market price is set by the inter-fuel arbitrage and eventually takes effect in all periods. This explains why the maximum PTG revenues occurs at 4500 MW where the arbitrage margins of PTG's gas sales in periods with 0€/MWh electricity prices are substantial, but as more capacity is added there is an erosion of its revenues from arbitrage. Therefore, adding greater installed capacities of PTG reduces the revenues until it reaches its long-run perfectly competitive outcome. The downward spikes in PTG profits reflect this price-setting effect of PTG in a period and appears large due to the market clearing price in a period extending over 876 hours at a time. Zero profits are reached at 6950 MW although marginal deviations from the precise optimal can also be explained by lumpiness in increments of PTG capacity and the number of hours in each time period used.

Figure 6: Within a Scenario Analysis 95% RES Target & 0 PTG Investment Costs



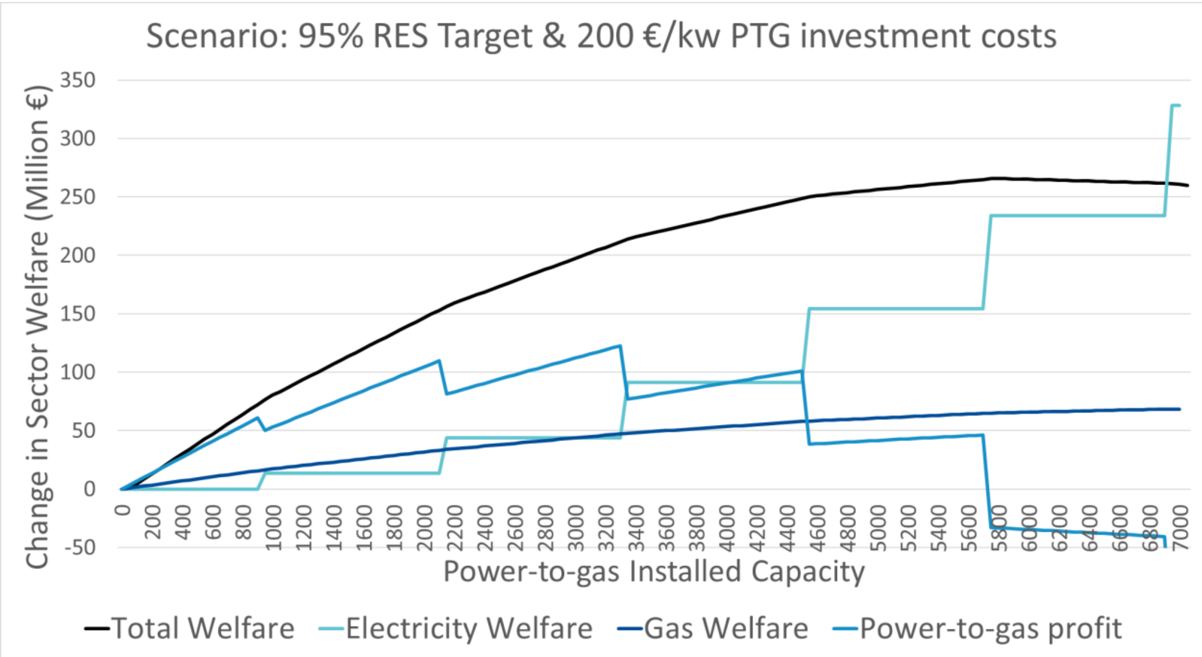
When higher PTG investment costs are considered, arbitrage profits must be significant enough to recover its investment costs. As a result, the PTG plant may not be profitable, except when PTG installed capacity is limited such that it does not absorb all spillage and the arbitrage revenues in these zero price periods make investment recovery possible. In the next subsection, this price-setting behavior will be analysed with respect to the impact on sector and total welfare.

3.2.2.2. Welfare Effects

Each combination of RES target and PTG annualized investment cost form a single scenario to analyse the impact of PTG on electricity and gas markets. For each scenario, in iterating from the baseline of 0 MW of PTG capacity by increments of 50 MW, we obtain a frontier of perfectly competitive outcomes which are sector equilibrium points representing optimizing agents.

A scenario of 95% RES and 200 €/kW PTG investment costs illustrated in Figure 7 demonstrates the welfare analysis process applied to all scenarios. The baseline welfare for each sector is a nominal welfare amount measured in millions of € to which change in welfare is compared for equilibrium points of the iterated PTG capacities. The long-run equilibrium can be identified by when total welfare, which is the sum of electricity welfare, gas welfare and PTG profits, is maximized. This grid search for agent-specific welfare and total system welfare equilibrium points confirm whether a misalignment in incentives is present.

Figure 7: Example of Scenario in Welfare Analysis



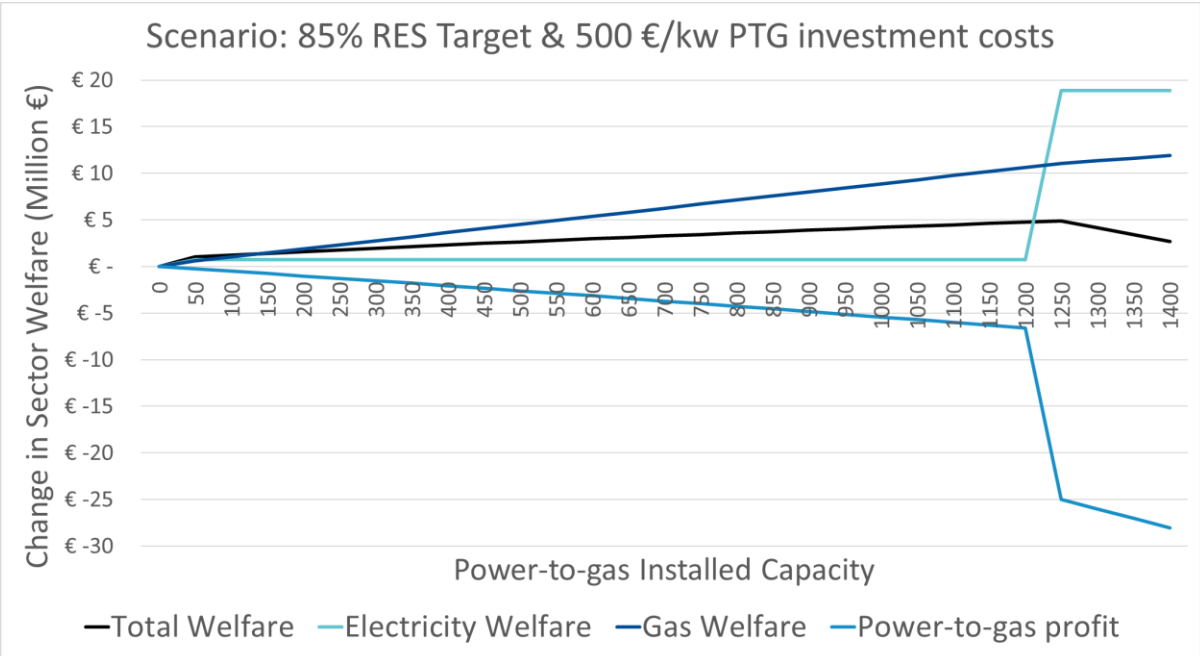
In this example, we do not observe a misalignment between sectors. In this scenario, the optimal equilibrium point for total system welfare is maximized at 5750 MW of PTG. Both the electricity and gas consumers benefit from PTG at the total welfare optimal equilibrium. For scenarios which have a positive change in total welfare and therefore an installed capacity of PTG greater than 0, both the electricity and gas sector benefit. The rationale underlining welfare changes across equilibrium points as more PTG is added will be explained further.

The positive welfare improvement in the gas sector can be explained by how PTG participates as a new supply source in the gas market. The gas market price formation is strongly dependent on the LTC procurement cost function. When the domestic supply source of hydrogen replaces some LTC imports, there is a slight downward pressure on gas prices, as observed in Vandewalle et al. (2015). This slight decrease in the gas price positively benefits gas consumers in a positive way, although marginally. Given this is a long-run equilibrium model, producer surplus of gas shippers is 0.

The positive welfare improvement in the electricity sector can be explained by how PTG productively uses otherwise spilled renewables and reduces the costs of the renewable premium for electricity consumers. The renewable energy premium is endogenously determined by the model to offset any market revenue shortfall of renewable generators such that RES investment costs are recovered. PTG, when deployed, can absorb spillage and thereby improves the capacity factors of the renewable generator's fleet and plays a price-setting role in the electricity market. As previously discussed, PTG absorption of zero marginal cost renewables can have direct price effects on the electricity market, leading to a price greater than 0 €/MWh. This price increase negatively affects electricity consumers. However, this loss is compensated by the reduction in the premium due to higher capacity factors of renewables which receive a non-zero price for their production. Overall, the net impact of the price making behavior of PTG on electricity welfare is positive, signifying that the gains from the reduction in renewable premium costs are greater than the loss from higher prices in the power market. Given this is a long-run equilibrium model, producer surplus of all generators is 0.

Note however we do observe a small issue with misaligned incentives related to the PTG actor. At the optimal welfare point, the PTG actor is making a loss. In the above scenario, this loss is partially explained by lumpiness. Note that this lumpiness can decrease after introducing smaller increments in PTG capacity and/or introducing more demand periods[1]. However, we noticed from some scenarios the issue is more than only lumpiness. In a couple scenarios, as in Figure 8, PTG is always loss-making, but is welfare optimal to invest in it at 1250 MW. The intuition behind this observation is that subsidizing PTG can make sense to reduce the cost of RES subsidies.

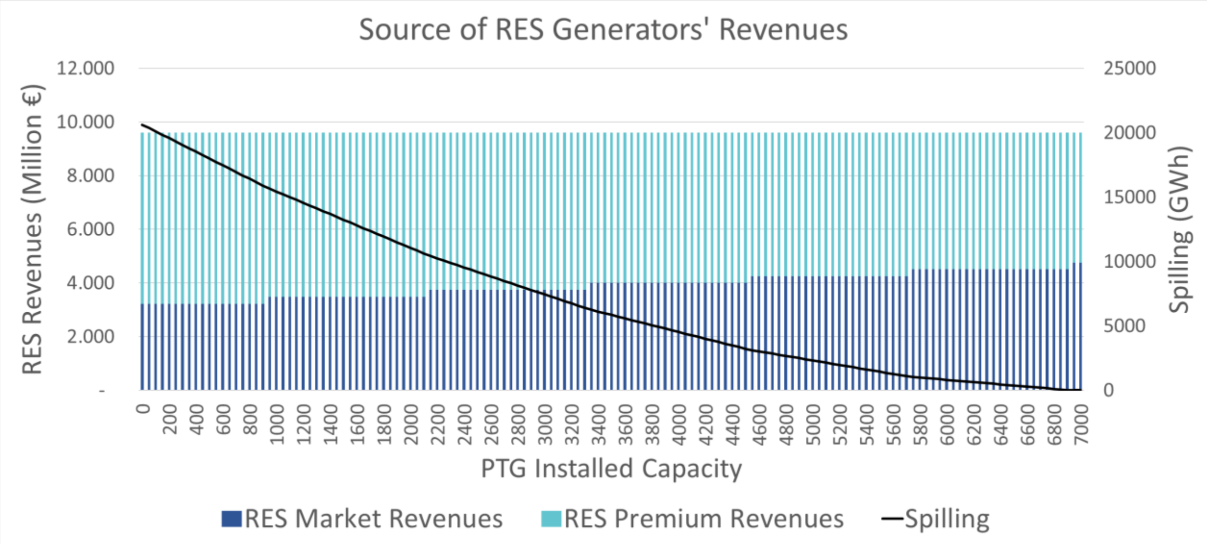
Figure 8: Potential for Misaligned Incentives in Welfare Analysis Scenario



[1] We checked for this issue of lumpiness relative to these two parameters.

Another impact of PTG on the electricity market is the renewable premium amount needed by RES generators. When PTG is setting the electricity market price above 0 €/MWh, then more market revenues support renewable investment recovery, thereby replacing part of the out-of-market capacity based premium. For the 95% RES target and 200 €/kw PTG investment cost scenario, this reduced dependence on the out-of-market capacity based premium is depicted in Figure 9. At the welfare optimal installed capacity of 5750 MW, the premium was reduced by 13% of total RES costs in favor of market-based revenues.

Figure 9: Breakdown of RES Generators' Revenue from Electricity Market and Out-of-market Capacity Based Premium



However, the renewable premium is designed to complement revenues recovered from the market and for this reason is sensitive to the electricity price. If the electricity price is sufficiently high, either due to high commodity prices (i.e. gas or CO2 prices), then it is possible RES generators can recover more revenue through the market and reduce the reliance on the premium. For this reason, this is a stylized observation. Similarly, dependence on a RES premium is also relative to the total investment costs which must be recovered. As RES investment costs decrease further into the future as they become more cost competitive, it follows that the RES premium could also reduce.

Here we see that moderate amounts of PTG capacity can significantly contribute to the reduction of spilled renewables. Spillage is reduced by 95% to 1,029 TWh from 20,629 TWh after installing 5,750 MW of PTG in the above scenario. Moderate amounts of PTG can significantly reduce RES spillage. In another scenario with PTG investment cost of 500 €/kw, at 85% and 95% RES targets, the optimal installed capacity of PTG of 1250 MW and 4450 MW reduces spillage by 51% (3.153 TWh) and 84% (17.278 TWh), respectively.

Table 2 provides a summary of the optimal installed capacity of PTG for multiple scenarios covering different combinations of RES targets and PTG investment costs. The positive total welfare improvement is calculated relative to the baseline of 0 MW of PTG for an exogenous RES target. For all scenarios, the positive change in total welfare (M€), if observed, is listed in the second row beneath the colored cell which states the optimal installed capacity of PTG (MW). In the third row, PTG profit (M€) is listed to further discern the lumpiness effect. The cell is colored in orange to highlight the two scenarios in which PTG is always loss-making activity but welfare enhancing. PTG installed capacity is 0 MW when there is a negative change (- Δ) in total welfare, which means that if PTG is not installed because it is not welfare enhancing nor profitable.

Table 2: Welfare Analysis - Base Case

SCENARIOS				
power-to-gas costs €/kw				RES Target
1000	**500**	**200**	**0**	
no spilling				**55%**
no spilling				**60%**
no spilling				**65%**
0	**0**	**0**	**500**	
- Δ	- Δ	- Δ	8 M€	**70%**
-	-	-	0 M€	
0	**0**	**250**	**1450**	
- Δ	- Δ	3 M€	28 M€	**75%**
-	-	-1 M€	0 M€	
0	**50**	**1300**	**2500**	
- Δ	1 M€	19 M€	65 M€	**80%**
-	0 M€	-6 M€	0 M€	
0	**1250**	**2450**	**3650**	
- Δ	4 M€	58 M€	126 M€	**85%**
-	-25 M€	-12 M€	0 M€	
0	**2650**	**3900**	**5100**	
- Δ	37 M€	132 M€	228 M€	**90%**
-	-16 M€	-21 M€	0 M€	
900	**4450**	**5750**	**6950**	
6 M€	117 M€	265 M€	396 M€	**95%**
-9 M€	-30 M€	-33 M€	0 M€	
4450	**7200**	**9600**	**10800**	
140 M€	429 M€	684 M€	890 M€	**100%**
-61 M€	-57 M€	-60 M€	0 M€	

From our stylized model, we observe that both the RES target and PTG investment costs are important factors in making the business case. A 0 €/kw represents a particular case in which PTG is free or entirely subsidised with the burden not falling on electricity nor gas consumers. The optimal PTG capacity in this case would be enough to absorb 100% of the spillage for any given RES target. At high RES targets, more spillage occurs across more periods which improves the capacity factor of PTG if installed. At high PTG costs, the welfare benefits for the electricity and gas sector do not often outweigh the PTG investment costs. The installed capacities of PTG found in this table describe a particular sector coupling configuration and is subject to change based on power system characteristics. These factors will be considered in the subsequent sensitivity analysis.

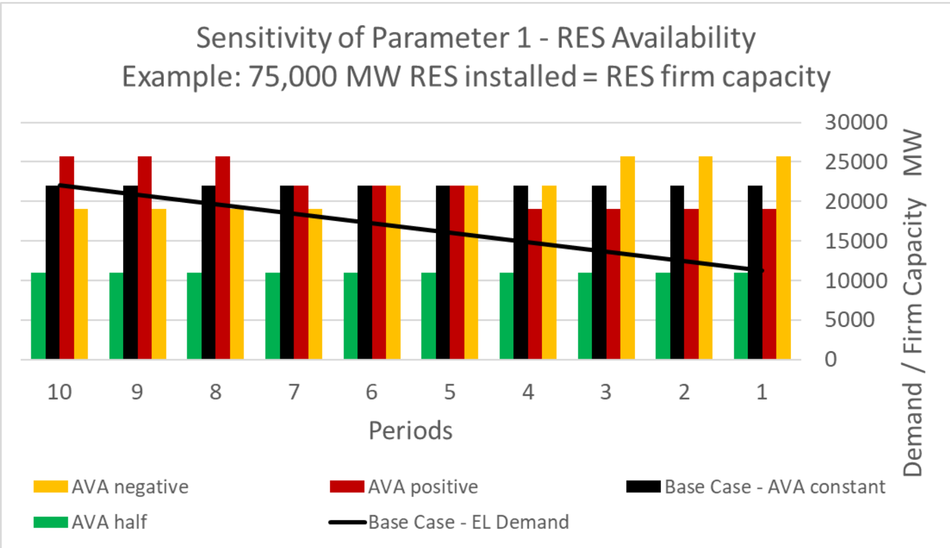
3.2.2.3. Sensitivity Analysis

A sensitivity analysis is carried out in order to characterize the impact of power system characteristics on the welfare optimal deployment of PTG. The two most prominent parameters under consideration are the RES availability factor specified in each period and the slope of the LDC. In the base case, the RES availability factor is a constant 30% in all periods. For an RES installed capacity of 75000 MW, the firm capacity provided is then 22500 MW for each hour in all periods. In the base case, the LDC is upward sloping at a rate of 1200 MW per period. The difference between the peak (22000 MW) to baseload (11200 MW) leads to a demand spread of 10800 MW. These sensitivities highlight how the potential of PTG can significantly vary from the base case resulting from system-wide parameters which impact energy spillage.

The first set of sensitivities provide alternative RES availabilities which are represented graphically in Figure 10. As the electricity LDC is not ordered time series, when the RES availability is not constant across all periods, a different specified correlation between electricity demand and RES availability is assumed. Instead of estimating a precise correlation in this regard for a specific geographical location or RES resource, two availability cases – positive and negative correlation with LDC - were considered. Each of these cases has an equal average availability as the base case.

For any given renewable capacity installed, a negatively correlated availability (AVA negative) defines RES production to be lower in high demand periods than low demand periods. As RES targets increase, more RES capacity is required to meet high demand periods and additionally more spillage occurs in low demand periods, when compared to the base case. On the other hand, a positively correlated availability (AVA positive) defines RES production to be higher in high demand periods than low demand periods. In this case, spillage is generally reduced in all periods to meet an RES target, when compared to the base case. These differences in installed PTG capacity are summarized in scenario tables in the Appendix. For the same scenario of 95% RES target and 500 €/kw for PTG costs, the PTG installed capacity is nearly four times greater in the negatively correlated availability case compared to the positively correlated one.

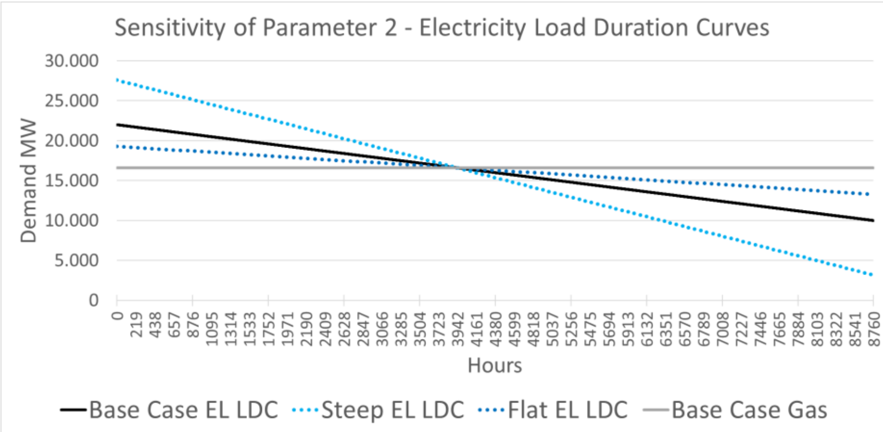
Figure 10: RES Availability Sensitivities



Another relevant sensitivity simulates the effect of halving the 30% RES availability factor (AVA half), specifying a 15% RES availability factor instead. This modification doubles the RES installed capacity required to provide an equal amount of firm capacity, thereby doubling the RES capacity investment necessary.

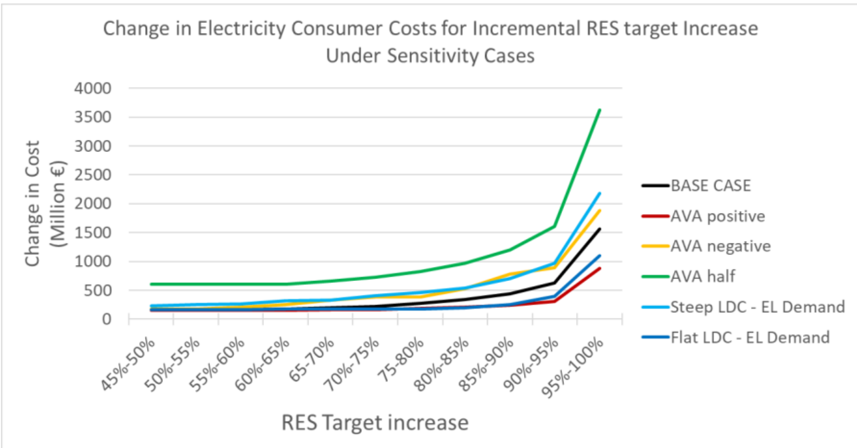
The second set of sensitivities provide alternative shapes of LDCs which could represent underlying power system characteristics such as seasonality related to demand types observed in a typical year which cause the demand spread between peak load and base load to vary. For example, electric instead of gas used for residential heating applications which typically follow a seasonal temperature dependent pattern could cause a larger demand spread. Two cases are illustrated in Figure 11, a flat and steep LDC, which are of equal size in gross electricity consumption and have the same 30% RES availability factor as the base case. For a more steep LDC, spilling begins at lower RES targets (30%) and there is more spillage overall compared to the base and flat LDC cases. These differences in installed PTG capacity are summarized in scenario tables in the Appendix. The most evident observation is when spilling actually begins whether at 35% in the flat LDC case or 85% in the steep LDC case. Although these are stylized LDCs represented, reshaping the LDC is a crucial input for determining optimal PTG installed capacity.

Figure 11: Electricity LDC Sensitivities



The cases examined in the sensitivity analysis each hold a different baseline – market and premium costs for electricity consumers when no PTG is installed – considering all possible RES targets, as explained in Section 3.2.1. These cases can be cross-compared through the change in costs for increasing RES targets incrementally by 5%, as depicted in Figure 12. This cost analysis for electricity consumers directly captures the impact of system parameters on the electricity welfare baseline. When the costs are increasing over an RES target range, PTG has an opportunity to contribute to welfare improvement.

Figure 12: Comparison of Electricity Consumer Cost for Incremental RES Targets Across Sensitivities



3.2.3. Limitations of our approach and implications for conclusions

In what follows, we first discuss why our sensitivity analysis is incomplete, and then discuss the implications for the kind of conclusions we can draw from our analysis.

First, why is our sensitivity analysis incomplete? We did illustrate that the conditions under which PTG becomes profitable and significantly improves the welfare of the electricity and gas system, depends on the renewable energy push that is put on that system and the detailed characteristics of that system. There are many factors that play a role, and we did not model all of them. Some omissions imply that we are underestimating the impact of PTG, while others imply that we overestimating the impact of PTG. An illustration of underestimation is that we assume a constant 30% RES availability factor while actual firm capacity provided by RES could be lower in certain periods. Also we do not model the ancillary services markets, which might be an additional source of revenue for PTG, and an additional system benefit that this technology could deliver. Profitability of PTG could also be improved by the industrial demand for hydrogen, either through renewable electricity ‘green hydrogen’ or through pre-combustion Carbon Capture and Storage ‘blue hydrogen’, which is also additional revenue that is not considered in the current version of our model. An illustration of overestimation is that we focused on PTG as the only means to absorb RES spillage. In practice, however, the competitive landscape offers a diverse set of participating technologies and pathways to market to deal with the system imbalances that VRES may cause. We do not claim by any means that PTG is the only sector coupling technology to be studied. Further research may eventually show our findings to hold for other power conversion technologies, such as Power-to-heat, Power-to-liquids and batteries.

Second, what are the limitations of our approach and what implications does this have for the kind of conclusions we can draw from the analysis? This model has not been designed to forecast under which assumptions PTG will become profitable and impact the electricity and gas system. As stated in the introduction, we did develop the model to check if we should be concerned about misaligned incentives between the relevant actors in the system. If PTG would become profitable and welfare improving, will the electricity and gas actors spontaneously come together and invest in this technology, or should regulators anticipate that the investment risks to be sub-optimal so that intervention might be needed. In other words, who will benefit from PTG and will we automatically converge to total welfare maximization or is the distribution of welfare such that we might not reach the optimal point. This is what our model has been designed for, and what we focus on in our conclusions. Of course, the model also gives insights on when PTG might become profitable, but these insights need to be treated more carefully so we decided not to highlight them in our conclusions.

4. Conclusions

In this paper, we analyzed the welfare and price effects of sector coupling with PTG. We advanced a stylized equilibrium model in order to identify potential misaligned incentives between the relevant actors in the electricity and gas system. In a numerical example, we studied the long-run coupled market equilibrium in multiple scenarios combining electricity RES targets and PTG investment costs. Across scenarios, we studied the price effect induced by the participation of PTG in the electricity market and the impact on the gas market. Within each scenario, we compared the sector and total welfare optimal installed capacity of PTG and distribution of welfare to identify misaligned incentives.
Our three main findings are the following.

First, in order for PTG to recover its investment costs, arbitrage profits must be significant enough. As more PTG capacity is installed, we observe a peak and then erosion of arbitrage revenues. This is due to PTG’s price setting role based on the inter-fuel arbitrage in the electricity market when sufficient capacity is installed which can absorb energy spillage. In some scenarios, the optimal level of PTG investment corresponds to a loss for the involved actor.

Second, when PTG is installed in a scenario, signifying a positive impact on system welfare, PTG absorbs spillage which benefits electricity consumers thanks to a reduction in the RES capacity-based premium. At the same time, gas consumers benefit from PTG's alternative supply which reduces gas market prices through a decreased dependence on Long Term Contracts. Therefore, misaligned incentives between sectors may be limited.

Third, a sensitivity analysis highlights key electricity system parameters, including the correlation between the electricity Load Duration Curve (LDC) and availability of RES, as well as the shape of the LDC. Given these system characteristics, it is possible to determine the need for and value that PTG can bring as a means to evacuate spillage.

We derive two main sector coupling conclusions from these findings.

First, in scenarios in which PTG is profitable and welfare improving, electricity and gas consumers both benefit from lower prices. This suggests that these sectors have an incentive to cooperate around PTG. We had to analyse all the welfare and price effects to come to this important conclusion.

Second, even if it was not the focus of our analysis, we did discover another issue. In some scenarios, total welfare is maximized at the level of PTG investment that is loss-making for the PTG investor. The intuition is that subsidizing PTG can make sense to reduce the cost of RES subsidies. This then opens the debate for PTG investment support via subsidies and/or grid tariffs.

In other words, we did not find an issue with misaligned incentives where we were expecting to find it, but we did find it where we were not looking for it.

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Appendix

KKT Conditions

$$(\mathrm{VC_s} + \lambda_l^{Gas} - \lambda_\mathrm{l}^{\mathrm{EL}}) \bullet \mathrm{T_l} - \rho_{\mathrm{l,s}}^- + \rho_{\mathrm{l,s}}^+ = 0, \quad \forall \mathrm{l} \in \mathrm{L}, \forall \mathrm{s} \in \mathrm{S} \tag{A.1}$$

$$\mathrm{CC_s} - (\sum_{l \in L} \rho_{l,s}^+ \bullet \mathrm{T_l}) - \xi_s = 0, \forall \mathrm{s} \in \mathrm{S} \tag{A.2}$$

$$(\mathrm{VCR_r} - \lambda_l^{EL}) - \mu_{l,r}^- + \mu_{l,r}^+ = 0, \forall \mathrm{l} \in \mathrm{L}, \forall \mathrm{r} \in \mathrm{R} \tag{A.3}$$

$$\mathrm{CCR_r} - \sum_{l \in L} (\mu_{l,r}^+ \bullet \mathrm{AVA_{l,r}} \bullet \mathrm{T_l}) - \sum_{l \in L} (prem \bullet \mathrm{T_l}) - \pi_r = 0, \forall \mathrm{r} \in \mathrm{R} \tag{A.4}$$

$$\sum_{r \in R} (xr_r) + \sum_{s \in S} (x_s) - \mathrm{D_l} - dptg_l - prem - \eta_l^{EL} = 0 \ \forall \mathrm{l} \in \mathrm{L} \tag{A.5}$$

$$(\lambda_l^{Gas} - (\mathrm{LTCint} + \mathrm{LTCslope} \bullet q_{l,c}) - \mu_{l,c} = 0, \forall \mathrm{l} \in \mathrm{L}, \forall \mathrm{c} \in \mathrm{C} \tag{A.6}$$

$$\sum_{c \in C} (q_{l,c}) - \mathrm{DG_l} - \sum_{s \in S} (x_{l,s}) + (dptg_l \bullet CONV) - \eta_l^{Gas} = 0 \ , \forall \mathrm{l} \in \mathrm{L} \tag{A.7}$$

$$\lambda_l^{EL} - \left(\lambda_l^{GAS} \bullet \mathrm{CONV}\right) - \delta_l^- + \delta_l^+ + \iota_l = 0 \ \forall l \in L \tag{A.8}$$

$$0 \le \rho_{l,s}^- \perp x_s \ge 0 \ , \quad \forall l \in L, \forall s \in S \tag{A.9}$$

$$0 \le \rho_{l,s}^+ \perp g_s - x_{l,s} \ge 0 \ , \quad \forall l \in L, \forall s \in S \tag{A.10}$$

$$0 \le \xi_s \perp g_s \ge 0 \ , \quad \forall s \in S \tag{A.11}$$

$$0 \le \mu_{l,r}^- \perp xr_{l,r} \ge 0 \ , \quad \forall l \in L, \forall r \in R \tag{A.12}$$

$$0 \le \mu_{l,r}^+ \perp gr_r \bullet \mathrm{AVA_{l,r}} - xr_{l,r} \ge 0 \ , \qquad \forall l \in L, \quad \forall r \in R \tag{A.13}$$

$$0 \le \pi_r \perp gR_r \ge 0 \ , \quad \forall r \in R \tag{A.14}$$

$$0 \le prem \perp \sum_{l \in L} \sum_{r \in R} xr_r \bullet T_l - \left(\mathrm{RENTARGET} \bullet \sum_{l \in L} ((\mathrm{D_l}) \bullet \mathrm{T_l}) \right) - \sum_{l \in L} (dptg_\mathrm{l} \bullet \mathrm{T_l}) \ge 0 \ , \quad \forall l \in L \tag{A.15}$$

$$0 \le \mu_{l,c} \perp q_{l,c} \ge 0 \ , \quad \forall \mathrm{l} \in \mathrm{L}, \forall \mathrm{c} \in \mathrm{C} \tag{A.16}$$

$$0 \le \eta_l^{Gas} \perp \lambda_l^{Gas} \ge 0 \ , \quad \forall l \in L \tag{A.17}$$

$$0 \le \delta_l^- \perp dptg_l \ge 0 \ , \quad \forall l \in L \tag{A.18}$$

$$0 \le \delta_l^+ \perp \mathrm{PTGCAP} - dptg_l \ge 0 \ , \quad \forall l \in L \tag{A.19}$$

Sensitivity Analysis Tables

RES Availability correlation with LDC

Sensitivity - RES availability positively correlated with Load Duration Curve				
SCENARIOS				
power-to-gas costs €/kw				RES Target
1000	**500**	**200**	**0**	
no spilling				**55%**
no spilling				**60%**
no spilling				**65%**
no spilling				**70%**
no spilling				**75%**
0	**0**	**0**	**400**	**80%**
- Δ	- Δ	- Δ	6 M€	
0	**0**	**0**	**1200**	**85%**
- Δ	- Δ	- Δ	20 M€	
0	**0**	**850**	**2050**	**90%**
- Δ	- Δ	12 M€	49 M€	
0	**600**	**1850**	**3050**	**95%**
- Δ	9 M€	45 M€	101 M€	
1650	**2850**	**3950**	**5150**	**100%**
65 M€	179 M€	278 M€	375 M€	

Sensitivity - RES availability negatively correlated with Load Duration Curve				
SCENARIOS				
power-to-gas costs €/kw				RES Target
1000	**500**	**200**	**0**	
no spilling				**55%**
0	**0**	**0**	**550**	**60%**
- Δ	- Δ	- Δ	9 M€	
0	**0**	**500**	**1700**	**65%**
- Δ	- Δ	7 M€	37 M€	
0	**650**	**1850**	**3100**	**70%**
- Δ	2 M€	39 M€	95 M€	
0	**2150**	**3350**	**4550**	**75%**
- Δ	6 M€	85 M€	171 M€	
0	**3600**	**4850**	**6050**	**80%**
- Δ	8 M€	130 M€	244 M€	
0	**4450**	**6700**	**7900**	**85%**
- Δ	41 M€	217 M€	366 M€	
1300	**4450**	**9200**	**10450**	**90%**
8 M€	137 M€	380 M€	578 M€	
3700	**6150**	**12000**	**13200**	**95%**
16 M€	255 M€	567 M€	819 M€	
4450	**10600**	**17200**	**18450**	**100%**
140 M€	572 M€	1009 M€	1361 M€	

Shape of LDC

Sensitivity - Steeper Load Duration Curve				
SCENARIOS				
power-to-gas costs €/kw				RES Target
1000	500	200	0	
no spilling				30%
0	0	0	250	35%
- Δ	- Δ	- Δ	4 M€	
0	0	0	1200	40%
- Δ	- Δ	- Δ	20 M€	
0	0	0	2100	45%
- Δ	- Δ	- Δ	35 M€	
0	0	650	3100	50%
- Δ	- Δ	9 M€	63 M€	
0	0	1700	4150	55%
- Δ	- Δ	24 M€	98 M€	
0	300	2750	5200	60%
- Δ	1 M€	45 M€	139 M€	
0	1450	3950	6400	65%
- Δ	4 M€	82 M€	198 M€	
0	2700	5150	7600	70%
- Δ	11 M€	123 M€	262 M€	
0	4050	6550	9000	75%
- Δ	36 M€	187 M€	352 M€	
0	4450	8050	10500	80%
- Δ	74 M€	265 M€	459 M€	
0	4800	9700	12150	85%
- Δ	129 M€	365 M€	590 M€	
1950	6850	11750	14200	90%
11 M€	228 M€	516 M€	780 M€	
4450	9450	14350	16800	95%
53 M€	381 M€	737 M€	1050 M€	
7350	14650	19550	20750	100%
255 M€	789 M€	1280 M€	1677 M€	

Sensitivity - Flatter Load Duration Curve				
SCENARIOS				
power-to-gas costs €/kw				RES Target
1000	500	200	0	
no spilling				55%
no spilling				60%
no spilling				65%
no spilling				70%
no spilling				75%
no spilling				80%
0	0	0	250	85%
- Δ	- Δ	- Δ	4 M€	
0	0	650	1250	90%
- Δ	- Δ	10 M€	32 M€	
0	1300	1950	2550	95%
- Δ	19 M€	67 M€	115 M€	
2400	4150	4800	5400	100%
75 M€	224 M€	355 M€	459 M€	

Notation

Sets

l	Period of load duration curve
s	Conventional technologies
r	Renewable technologies
c	Long term contracts

Parameters

Type	**Name**	**Description**	**Unit**
Demand	D_l	Electricity demand in period l	MW
	DG_l	Gas demand in period l	MWh
	T_l	Duration of period l. $\sum T_l = 8760$	Hours
Electricity Generation & Gas Supply	CC_s	Annual investment capacity cost for conventional s	€/MW
	CCR_r	Annual investment capacity cost for renewable r	€/MW
	VC_s	Variable cost for conventional s	€/MWh
	VCR_r	Variable cost for renewable r	€/MWh
	$AVA_{r,l}$	Availability factor for renewable r in period l	%
	$LTCint_c$	Intercept of simplified procurement cost function of long term contract c	€
	$LTCslope_c$	Slope of simplified procurement cost function of long term contract c	€/MWh
Power-to-gas	PTGCAP	Power-to-gas capacity installed	MW
	PTGINVC	Annual investment capacity cost for power-to-gas	€/MW
	CONV	Conversion efficiency of power-to-gas	%
Renewable Policy	RENTARGET	Minimal annual renewable energy produced and consumed	MWh

Variables

Type	Name	Description	Unit
(Primal) Variables	$x_{l,s}$	Generation of conventional plant s in time period l	MW
	g_s	Maximal generation (capacity) of conventional plant s	MW
	$xr_{l,r}$	Generation of renewable plant r in period l	MW
	gr_r	Maximal generation (capacity) of renewable plant r	MW
	$dptg_{l,p}$	Demand of power-to-gas p in period l	MW
	$q_{l,c}$	Quantity of gas procured from contract c in period l	MWh
(Dual) variables	$\rho^+_{l,s}$	Dual variable for maximal production constraint for conventional plant s in period l	€/MWh
	$\rho^-_{l,s}$	Dual variable for non-negativity $x_{l,s}$	
	ξ_s	Dual variable for non-negativity g_s	
	$\mu^+_{l,r}$	Dual variable for maximal production constraint for conventional plant r in period l	€/MWh
	$\mu^-_{l,r}$	Dual variable for non-negativity constraint $xr_{l,r}$	
	π_r	Dual variable for non-negativity constraint g_r	
	$prem$	Dual variable for RES target constraint	€/MW.h
	δ^+_l	Dual variable for maximal consumption constraint for power-to-gas in period l	€/MWh
	δ^-_l	Dual variable for non-negativity constraint $dptg_l$	
(Output) variables	λ^{EL}_l	Electricity price for demand period l	€/MWh
	λ^{Gas}_l	Gas price for demand period l	€/MWh
	$prem$	Renewable energy premium	€/MW.h

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