Modeling Gas-Electricity Coordination in a Competitive Market

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Abstract

As climate concerns, low natural gas prices, and renewable technologies increase the electric power sector’s dependence on natural gas-fired power plants, operational and investment models for gas and electric power systems will need to treat the interdependencies between these two systems to accurately capture the impacts of one on the other. Currently, few hybrid gas-electricity models exist. This paper reviews the use of computational models in electric power systems, the state of the art for gas-electricity models, and presents a new model and case study that illustrates a few effects of simultaneously considering the gas (purchases and capacity contracting) and electricity (power plants operation) system in a competitive market under uncertainty from renewable energy sources.
Introduction

A brief overview of the complex decision space in a power system

In developed countries, citizens tend to view electricity as a right, not as an energy commodity. Yet, the ease with which most consumers have access to electricity belies the complex nature of the electric power system. The planning, investment, and operation decisions that make electricity possible span timescales from seconds to decades and require careful consideration of future uncertainties such as demand, fuel availability, the environment, and government policy.

Much of the complexity and uncertainty related to planning and operating an electric power system stems from the fact that electricity supply and demand, unlike other energy commodities, must remain in instantaneous balance as a matter of physical law. In each power system, generators that produce electricity are connected to each other via thousands of miles of transmission lines and turn synchronously as a single, monolithic machine. Small differences between electricity supply and demand are instantaneously balanced by conversions between mechanical and electrical energy that speed up or slow down the frequency of this monolithic machine. Large deviations between supply and demand can lead to electrical and mechanical failures. Storage technologies, such as pumped hydro reservoirs, can serve as a buffer for some of these deviations by charging during times of excess supply and discharging during times of excess demand. However, because most power systems cannot economically store large amounts of electricity, balancing consumption and generation generally requires real-time adaptation at the demand and generation level.

Determining the economically efficient long-term investments and short-term operations that will balance consumption and generation pose a difficult challenge because these decisions are time-coupled. For example, long-term investment decisions directly impact short- and medium-term decisions for the duration of an investment’s lifetime. At short timescales ranging from seconds to hours, operators must decide which plants in its system to dispatch such that the chosen plants, in aggregate, will have the greatest chance of coping with all expected and unexpected changes (e.g., in demand, generator availability, and renewable generation) at the lowest cost. At medium timescales ranging from days to a few years, operators must make decisions about how to manage limited resources, such as hydro reservoirs to help meet peak demand while coping with uncertainty about future rainfall and water availability. At large timescales ranging from years to several decades, stakeholders must make appropriate investments such that the entire generation portfolio and transmission network can efficiently meet changes in expected demand while also complying with new regulatory policies such as a renewable portfolio standard. Because long- and medium-term decisions directly impact the range of
possible medium- and short-term decisions, determining the “correct,” economically efficient, optimal, welfare-maximizing investments and operations at each timescale under uncertainty poses a quantitatively complex challenge for all stakeholders in a power system.

Stakeholders in electric power systems

Before the 1990s, vertically integrated utilities operated most electric power systems around the world under cost-of-service remuneration. These utility companies implicitly acted as central planners; they made all short- and long-term decisions in their systems ranging from daily dispatch to generation and transmission investments. Under the supervision of a regulatory agency, a vertically integrated utility earned all of the costs of its business plus a fair rate of return (as determined by the regulator) in exchange for providing its customers with reliable electricity. Given the political and social consequences of electricity failures, although utility companies and regulators tended to err on the side of caution when making investment and operation choices and approving costs (leading to potentially inefficient choices), vertically integrated utilities generally handled their central planning responsibilities well, and electricity failures occurred infrequently.

When power systems began to “deregulate” and “liberalize” in the early 1990s, many governments around the world separated their vertically integrated utilities and created competition at the generation level to incentivize greater economic efficiency. Independent power producers that wanted to build a power plant and sell electricity could do so by requesting a connection to one of these liberalized power systems and then submitting bids to a market operator (in most power systems, the market operator and the system operator are the same entity). Markets exist today for many electricity “products,” including energy and reserve services differentiated by time.

In the process of creating these electricity markets, many of the central planning functions that vertically integrated utilities previously performed were either implicitly transferred to stakeholders such as regulators, system operators, utilities, and independent power producers, or lost due to market structures that misaligned individual incentives with the system’s total welfare. For example, today, concerns about failures that arise in liberalized electricity markets about broadly fall into three time-delineated categories: reliability in the short term, firmness in the medium term, and adequacy in the long term.

1 Transmission and distribution networks remained regulated as natural monopolies because of their economies of scale. Per unit capacity, larger capacity power lines cost less than smaller capacity lines. As such, allowing multiple companies to build smaller, overlapping networks would actually increase total consumer costs.
1. In the short term (seconds to days), if a system operator commits a power plant to operate in the next day, and then that power plant fails to start up because of a mechanical problem, the system operator must rely on the remaining plants that it has dispatched to make up the difference. While the owner of the generator holds financial responsibility for the energy that he cannot generate, to ensure the proper operation of the power system, the system operator must physically find a feasible combination of increased generation and decreased consumption to mitigate the effects of this real-time failure.

2. In the medium term (weeks to years), the owner of a portfolio of natural gas plants in a power system must contract for pipeline capacity in advance to prevent that owner from being unable to offer capacity from his gas plants at a later time in the year. In this situation, the owners of the gas plants may or may not hold financial responsibility for the electricity that they now cannot physically deliver (perhaps those owners had participated in an energy auction with the system operator, or they were planning to just sell their energy in the day-ahead market). Besides the economic losses that will incur the owner, depending on the reserve capacity of this power system and the fraction of capacity and generation that natural gas power plants provide, the feasible solution may entail higher marginal prices and rolling blackouts and, hence, the system operator again must find a feasible combination of increased generation and decreased consumption to make up the imbalance.

3. In the long-term (across multiple decades), independent power producers may decide not to invest in additional capacity that the system needs to meet future demand changes. For example, they may decide not to build a peaker plant because they do not expect to fully recover their fixed costs through the current available revenue streams, or they may decide not to build a wind turbine despite a renewables mandate because the feed-in tariff is too small.

The examples in this section illustrate the types of economic and physical problems and uncertainties (e.g., demand forecasts, plant and fuel availabilities, new technologies, environmental concerns, and new regulations) that affect all stakeholders in electric power systems. To address these types of problems in a liberalized system, individual stakeholders must act under “correct” market incentives and policies such that their individual behaviors achieve a desired outcome in aggregate (e.g., a reliability or efficiency target); determining what the “correct” set of incentives and policies are is not trivial. Similarly, vertically integrated utilities face similar challenges, but their regulated business models lead to different economic efficiency challenges, and determining the “correct” level of efficiency is also not trivial. To tractably grasp the complexity of these
types of challenges and to understand how one decision affects another, power systems stakeholders—regulators, system operators, independent power producers, and utilities—rely on computational models to gain insight about what the “correct” set of long-term outcomes, short-term operations, market rules, and government policies should look like.

**Computational models for gas-electricity systems**

Stakeholders in electric power systems use computational models to understand and make optimal decisions about operations and investments. For example, a system operator might use an optimal power flow model to determine the lowest cost set of electricity bids that will meet tomorrow’s demand, as well as to calculate the corresponding marginal prices for clearing day-ahead transactions. With this same optimal power flow model, in a different power system, a regulator might analyze a vertically integrated utility’s operations to approximate its operating costs and set the next rate base. This dual use for optimal power flow models and other electricity models is not coincidental: under the traditional economic assumptions of perfect competition, complete information, and rational behavior, the optimal, economically efficient decisions for an electric power system—regardless of whether it operates as a vertically integrated utility or as a market with individual agents—are the same. (I.J. Perez-Arriaga & Mesequer 1997) While the assumption of perfect competition is strong, many electricity models can also represent various levels of competition; the key idea is that these models can give quantitative insights and benchmarks about what optimal outcomes should resemble. As such, stakeholders in electric power systems rely on models for both operational and regulatory purposes.

Computational models such as the optimal power flow example above operate by capturing the salient features of a power system and then calculating a set of feasible decisions that best meets a specific system objective. A power system’s physical and operational constraints define the set of possible decisions that the system can take, and the system’s objective typically involves either minimizing total cost or maximizing profit. Typical electricity models that address short-term concerns include economic dispatch (to determine the least-cost plants that can meet demand), unit commitment (economic dispatch with an explicit consideration for which plants to turn on and off), and optimal power flow; in the medium-term, hydrothermal coordination models provide insights about how to use limited storage resources such as water stored in a reservoir; and in the long-term, capacity expansion models explore the investment decisions needed to meet future demand and policies. At the simplest level, these models are nontrivial math problems, and for a real-world sized system, they can require significant computing resources and time to solve. Additionally, depending on the mathematical formulation, some of these models may not have a provable optimal solution. Advances in operations research have greatly improved the size of problems that can be solved. For examples and more details about the state the of art of electricity models, see (Ventosa et al. 2005) on electricity markets;
(Padhy 2004) on unit commitment; and (Qiu et al. 2009) on optimal power flow.

**State of the art for gas-electricity models**

Traditionally, electricity models have assumed that thermal plants such as coal and gas generators have access to unlimited and completely reliable fuel supplies. However, recently, due to environmental concerns, low natural gas prices, and the operational flexibility of gas plants, many power systems are increasingly relying on natural gas as a primary source of energy for electricity generation. As this trend continues, the traditional models that have guided operations, investments, and policies in these power systems will need to take into consideration additional constraints that arise from the coupled gas-electricity system, or risk missing potential failures related to the coupling. Despite these interdependencies, thus far, the academic literature contains relatively few articles about hybrid electricity-gas models. The remainder of this section reviews the current state-of-the-art; many of the papers presented in this section are drawn from references found in (Rubio et al. 2008).

For a single snapshot time period, various authors have proposed models that jointly analyze the gas and power system by including the gas network and compressor stations:

- (Munoz et al. 2003) propose a model that evaluates the maximum amount of electric power generation possible from all of the combined-cycle power plants in a power system, taking into consideration gas demand by nonelectric customers, the gas network, and gas availability. Many reliability models take as inputs information about a plant’s maximum output. Traditionally, reliability models have considered the maximum output of thermal plants as a constant parameter. However, this assumption does not hold under fuel uncertainty. In addition to updating the treatment of combined-cycle plants in reliability studies, this model also introduces a new stakeholder in the gas-electric system that did not previously exist in the electric power system alone: nonelectric consumers whose demand for gas (perhaps as a heating source) might preempt demand for gas in the electric sector.

- (An et al. 2003) propose an optimal gas- and power-flow model that maximizes the total social welfare by summing benefits for all electrical and gas consumers and subtracting the cost of all operations. Similarly, (Unsihuay et al. 2007) propose an optimal gas- and power-flow model that minimizes costs. Unlike traditional welfare-maximizing electricity models, these hybrid model recognize the welfare of all agents (consumers and producers) in both systems when determining the optimal set of gas and power flows and corresponding marginal prices.

- (Urbina & Z. Li 2008) propose a cost-minimizing security-constrained unit commitment model that also takes into consideration optimal gas flows and interruptible gas contracts.
In the short term, (M. Shahidehpour & Wiedman 2005) discuss the impact on the power system of different contingencies in the gas infrastructure that cut off the supply of NGPPs; (T. Li et al. 2008) solve the unit commitment problem subject to gas network constraints with the possibility of fuel switching; (Chaudry et al. 2007) include line-pack capacity and gas storage facilities when minimizing the gas supply, gas operation and electricity generation costs; and (Liu et al. 2009) consider, besides gas storage, compressor stations to the solve the unit commitment problem.

In the medium and long term there is little literature to our knowledge. In the medium term, (Bezerra et al. 2006) propose a dynamic programming model to obtain the operation plan of hydrothermal and gas systems subject to stochasticity; and (Dueñas et al. 2012) seek to maximize the profits when managing gas supply contracts (including gas network congestions) in imperfect power markets. In the long term, (Unsihuay-Vila et al. 2010) extend their single period model to capacity expansion of both systems.

Growing importance of natural gas in electric power systems

During the last two decades, natural gas has appeared as a relevant source of energy for electricity production. Gas consumption by the electric sector in the U.S. has increased 2.24 times from 1997 to 2012. Furthermore, technological improvements in shale gas extraction and the subsequent reduction in costs have boosted reliance on natural gas for electricity generation. But, beyond these facts and numbers, two main reasons explain the preference of gas over other fossil fuels, such as coal or oil distillates. First, while gas prices may not always be lower than coal prices in monetary units per unit of released thermal energy, the higher conversion efficiency of natural gas power plants (NGPPs) with respect to coal power plants (60% and 30%, respectively and environmental regulations that limit or tax CO\textsubscript{2}, SO\textsubscript{2}, and/or NO\textsubscript{x} emissions\textsuperscript{2} make gas prices habitually lower than any other fossil fuel. Second, because NGPPs have significantly lower investment costs than other thermal plants, their rate of return on investment is relatively larger than other fossil fuel technology.

The increasing importance of NGPPs in current electricity systems justifies the joint analysis of gas and electricity systems. Although huge investments have taken place in gas systems to adapt their infrastructure to growing demand, generation companies sometimes face scarcities of gas pipeline capacity that may prevent a company from participating in the electricity market. Therefore, if several consumers (households, industries, or generation companies) share the pipeline and the capacity might be scarce at some future moment (e.g., in the middle of winter), contracting capacity in advance, which is similar to make a

\textsuperscript{2} Natural gas is said to be the cleanest fossil fuel. According to Energy Information Administration of the U.S., it emits half as much CO\textsubscript{2} and a third as much NO\textsubscript{x}. SO\textsubscript{2} emissions from gas are negligible.
hotel reservation, is very interesting for generation companies. The objective of the model presented below is to analyze pipeline capacity contracting by a generation company that shares the pipeline with other consumers.

Besides contracting gas pipeline capacity, the generation company must acquire gas. The gas consumers, and the generation company, can purchase gas in the spot market. But the higher the demand, the higher the price. As long as the generation company is competing in the electricity market with other producers, the previously defined objective extends to include the analysis of pipeline capacity contracting by a generation company that shares the pipeline with other gas consumers and participates in a gas spot market and in an electricity market.

NGPPs have an additional competitive advantage over most thermal power plants: they offer operational flexibility at reduced costs. Nowadays, renewable energy sources introduce intermittency in electricity systems. NGPPs have greatly supported the integration of renewable energy sources and improved the power system stability. However, in the context of liberalized electricity markets, generation companies must be ready to respond to sudden changes in renewable power generation. They must incorporate the uncertainty of renewable energy sources into their decision-making process, particularly when they contract for pipeline capacity well in advance. Consequently, our previous objective is finally extended to analyze pipeline capacity contracting by a generation company that shares the pipeline with other consumers. This generation company also participates in a gas spot market and an electricity market, and the market clearing is subject to the uncertainty of renewable energy sources.

**Coupling gas and electricity decisions under uncertainty**

The main objective of the model is to simulate the behavior of a generation company that owns a set of NGPPs, purchases gas in spot markets, and contracts capacity to supply its NGPPs. The model presented in this paper has tried to fill a gap that is of concern in current deregulated gas and power systems: the long- to medium-term decisions related to contracting pipeline capacity and the short-term decisions related to NGPP operation subject to the uncertainty of renewable power generation.

There are two markets at both extremes of the figure: the gas spot market and the electricity market; and one physical infrastructure, a gas pipeline, that connects both markets. The purchased gas flows through the pipeline, as long as capacity has been contracted, to the electricity market or to other gas consumers, such as industries or households. But the gas consumption of the electricity market depends on the market-clearing process in which the gas technology competes with other thermal (coal, gasoil, etc.) technologies. Let us assume that wind and solar are always dispatched.
In short, there is a zonal gas spot market, \( z \). A gas pipeline connects the market to the gas consumers, \( e = 1,2,\ldots,E \). A balance between the inflows (market purchases) and the outflows (demands) is monitored each day, \( d = 1,2,\ldots,D \). Part of the gas demand satisfies the industrial users and households, and another part feeds the NGPPs. These power plants together with other thermal (coal, gasoil, etc.) power plants constitute the group of power generators, \( g = 1,2,\ldots,G \), which satisfy the residual thermal electricity demand (after the dispatch of the renewable energy sources). As long as renewable generation is subject to uncertainty, the residual electricity demand will be defined for different scenarios, \( k = 1,2,\ldots,K \).

The model, a mixed-integer quadratically programming (MIQP) problem, is formulated as a combination of a quadratically programming (QP), a linear programming (LP), and a mixed-integer programming (MIP) problems. We start with the description of the gas spot market model. Then we present the capacity contracting model. Finally, we introduce the electricity market model and its link to the gas system. During the description of the model, uppercase and Greek letters stand for parameters, while lowercase letters stand for continuous and positive variables (except when explicitly indicated).

**Optimizing gas purchases**

Let us consider that within the gas spot market the dependence of the marginal gas cost \( c(\nu_{\text{HUB}}^{zdk}) \) on the daily purchases \( \nu_{\text{HUB}}^{zdk} \) can be represented by an affine function with cost intercept \( \alpha_0 \), and cost slope \( \alpha_1 \):

\[
c(\nu_{\text{HUB}}^{zdk}) = \alpha_0 + \alpha_1 \cdot \nu_{\text{HUB}}^{zdk} \quad (1)
\]

The consumers acquire gas at the zonal hub to comply with their certain conventional (industry and households) demand \( D_{\text{CNV}}^{zed} \), and with the variable, and uncertain, demand of their NGPPs \( d_{\text{NGPP}}^{zedk} \):

\[
\nu_{\text{HUB}}^{zdk} = \sum_e (d_{\text{NGPP}}^{zedk} + D_{\text{CNV}}^{zed}) \quad \forall z,e,d,k \quad (2)
\]
Even though the gas spot market is liquid and large enough, and the purchases are not limited, the total demand will be constrained by the pipeline capacity:

$$\sum_e (d_{NGPP}^{zdk} + D_{CNV}^{zdk}) \leq Q_{OUT}^{zdk} \quad \forall z, d, k \quad (3)$$

Naturally, the consumers would like to acquire gas at its minimum cost, or, concisely, the consumers minimize the expected acquisition costs:

$$\min_{v_{zdk}} \sum_{z,d,k} \omega_k \cdot c(v_{HUB}^{zdk}) \cdot v_{HUB}^{zdk} = \sum_{z,d,k} \omega_k \cdot (\alpha_0 + \alpha_1 \cdot v_{zdk}^{HUB}) \cdot v_{zdk}^{HUB} \quad (4)$$

The new parameter $\omega_k$ is the weight of each scenario and represents the probability of occurrence of the scenario. Naturally, the sum of the weights is equal to one.

The objective function (4) subject to the balance constraint (2) and the maximum pipeline capacity (3) constitutes a QP problem (quadratic objective function and linear constraints) that minimizes the expected gas acquisition costs considering uncertainty in renewable power generation.

**Optimizing pipeline capacity contracting**

In broad terms, the operator offers capacity contracts with different time scopes. Accordingly, the consumers can contract capacity in the long term $h^{OUT}_{lez}$ (i.e. during several years); in the medium term $h^{OUT}_{lzm}$ (i.e. during a month); and in the short term $h^{OUT}_{lezd}$ (i.e. during a day). The correspondence between the time scopes and the time horizons follows a standard that commonly takes place in reality. Standardized long-, medium- and short-term capacity contracts expire several years later, the next month or the next day, respectively. In addition, we consider that long- and medium-term contracts represent firm capacity contracts, while short-term contracts characterize interruptible capacity contracts since the gas consumers cannot be sure that enough free capacity will be available when the time of contracting comes. The immediate consequence is that short-term contracting decisions are different for each scenario, while long- and medium-term contracting decisions are common for all the scenarios.

Capacity prices vary with the time scope, being habitually less expensive to contract capacity in the long term $FC^{OUT}_z$, than in the medium term $FC^{OUT}_{zm}$; and in the medium term than in the short term $FC^{OUT}_{zd}$, as the pipeline operator is anticipating incomes and reducing the risks of keeping idle capacity. In addition, the operator may apply a variable tariff $VC^{OUT}_{zed}$ to the gas flow.

Daily, each gas consumer holds a portfolio $h^{OUT}_{zedk}$ of long-, medium-, and short-term firm capacity contracts:
The daily portfolio includes the acquisitions $h_{zde}^{\text{OUT}}$ and releases $h_{zde}^{\text{IN}}$ that take place in secondary capacity markets, where capacity is negotiated:

$$\sum_e h_{zde}^{\text{OUT}} = \sum_e h_{zde}^{\text{IN}} \quad \forall z,d,k \quad (6)$$

Similar to the gas demand that is limited by the pipeline capacity (3), the consumers’ total capacity portfolios are constrained by the maximum capacity of the pipeline

$$\sum_e h_{zde}^{\text{OUT}} \leq Q_{z}^{\text{OUT}} \quad \forall z,d,k \quad (7)$$

If the consumer has contracted enough capacity, the operator will let the amount of gas flow through the pipeline:

$$d_{zde}^{\text{NGPP}} + D_{zde}^{\text{CNV}} \leq h_{zde}^{\text{OUT}} \quad \forall z,e,d,k \quad (8)$$

There is one common long-term and medium-term contracting decision for all the scenarios as firm capacity contracts may be formalized well before (up to several years before) the time of operating the NGPPs that is, however, subject to the uncertainty of the renewable energy sources.

Finally, the gas consumers minimize the resulting costs from contracting both firm and interruptible capacity:

$$\min_{h_{zde}^{\text{OUT}}, h_{zde}^{\text{IN}}, \omega_k, FC_{zde}^{\text{OUT}}, FC_{zde}^{\text{IN}}, \sigma_k} \sum_{z,e,k} \omega_k \left[ FC_{zde}^{\text{OUT}} \cdot h_{zde}^{\text{OUT}} + \sum_m FC_{zde}^{\text{OUT}} \cdot h_{zde}^{\text{IN}} \right] + \sum_{d,k} \left[ FC_{zde}^{\text{OUT}} \cdot h_{zde}^{\text{OUT}} + V C_{zde}^{\text{OUT}} \left( d_{zde}^{\text{NGPP}} + D_{zde}^{\text{CNV}} \right) \right] \quad (9)$$

The objective function (9) subject to the constraints (5)–(8) constitutes a LP problem that allows the gas consumers to optimize their portfolio of capacity contracts under uncertainty.

**Optimizing power plants operation**

The main consequence of the gasification of electric power systems is the dependence of the electricity price on the gas cost and, therefore, the importance of analyzing how generation companies operate in the gas system. Moreover, in scenarios of high demand, if the generation companies have not foreseen the requirements of pipeline capacity or gas purchases, the power system may face non-supplied energy situations.

Before describing the model, let us focus on electricity demand. Demand and
Supply must be balanced instantaneously because electricity cannot be stored at competitive costs. Modeling power systems with such a level of temporal detail would be intractable. For instance, markets that also utilize algorithms to determine the dispatch and the price “group the instants” in each hour. But even modeling in the long or medium term each hour may be troublesome. For this reason, traditionally, a load duration curve has been constructed and some load levels (e.g. peak and off-peak, working and non-working days) have been established that were able to capture the behavior of hydrothermal systems with no penetration of renewable energy sources\(^3\), in exchange for losing the chronology. Lately, since the deployment of renewable energy sources, the net load duration curve (demand minus renewable generation) is starting to be used to define the load levels. The main disadvantage of still using this procedure to define the load levels is that, for instance, off-peak load levels will combine hours with high demand and high wind conditions with (significantly different) hours with low demand and low wind conditions\(^4\). Moreover, the chronology should try to be maintained because the intermittency of the renewable energy sources can modify sharply the operation of the power plants (in contrast to the “calm” operation of old times). For these reasons, we define the load levels in a different manner: as the so-called states of the system. A state of the system is a predefined set of circumstances that occur simultaneously and frequently in the system during the analyzed period of time (a week, a month, a year, etc.); hence, each hour of the period is assigned to a state with the advantage of maintaining the chronology because the transitions between the states (i.e. the hours) are known. The way to define the states is explained with the next example.

Let us consider a small isolated system with windmills, and one diesel fuel power plant. The weather conditions will undoubtedly set the price of the electricity. Let us define four states as a combination of two events: high and low demand; high and low wind conditions. We now construct a scatter plot with the hourly demand in the X-axis and the hourly wind generation in the Y-axis and then apply a clustering technique to obtain four representative points out of the whole sample. Each hour will be linked to a state and the transitions between the states will be the number of the transitions between the hours. The four states are \(l_1\) (low demand, high wind); \(l_2\) (high demand, high wind); \(l_3\) (low demand, low wind); and \(l_4\) (high demand, low wind).

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\(^3\) The operation of traditional power systems was characterized by rigid structures: nuclear power plants were producing always; coal power plants shut down the weekends if demand was too low; hydro power plants shaved the peaks; and gas and/or oil distillates power plants adapted to the residual demand due to their flexibility.

\(^4\) In this example, spinning reserves are critical in high demand scenarios to answer to a sudden decrease of wind generation; not so in low demand scenarios.
Returning to the description of the model, we can define several power system states, $l=1,2,...,L$. Consequently, each day is made up of different states, whose duration in hours is known $T_{st}^{ST}$. As previously mentioned, the load levels are defined for a period of time (hereinafter, a month) and the chronology is not lost because the number of transitions between two states $l$ and $l'$ within the month is known $N_{mnlk}^{RN}$.

We have defined the net electricity demand $D_{mlk}^{PWR}$ in each load level within the month as the difference between the electricity demand and the renewable power generation. As a result, there is a scenario of net electricity demand for each scenario of renewable power generation and, therefore, different state durations and transition matrices for each scenario. The generation companies, who own thermal power plants, produce an amount of electricity $q_{gmlk}$ to cover the monthly electricity demand:

$$D_{mlk}^{PWR} = \sum_{g} q_{gmlk} \quad \forall m, l, k : p_{gmlk}^{PWR}$$ (10)

One advantage of using QP and LP problems is the possibility of obtaining the dual variables of the technical constraints whose economic interpretation is usually of interest. For instance, (10) provides the electricity price $p_{gmlk}^{PWR}$.

The generated quantity is limited by the maximum power $Q_{g}^{MAX}$, the technical minimum $Q_{g}^{MIN}$, and a binary decision variable that reveals whether the group is committed $u_{gmlk}$:

$$q_{gmlk} \leq Q_{g}^{MAX} \cdot u_{gmlk} \quad \forall g, m, l, k$$ (11)

$$q_{gmlk} \geq Q_{g}^{MIN} \cdot u_{gmlk} \quad \forall g, m, l, k$$ (12)
Nevertheless, the commitment of a group depends on the start-up and shut-down decision. If a group starts up between the states \( l \) and \( l' \), it will be committed during the state \( l \). In contrast, this group will not be committed anymore, if it shuts down between the states \( l' \) and \( l \). The following constraint that includes the start-up \( u_{gml'k}^{UP} \) and shut-down decisions \( u_{gml'k}^{DN} \) describes these processes:

\[
\begin{align*}
u_{gml'k}^{UP} - u_{gml'k}^{DN} &= u_{gml'k}^{UP} - u_{gml'k}^{DN} \quad \forall g, m, l, l', k
\end{align*}
\] (13)

A fact worthy of mentioning is that the start-up and shut-down decision variables need not to be binary, but limited between zero and one, because their value is automatically determined by the binary commitment decisions.

The generation companies, within a perfectly competitive framework, minimize the operating costs of their thermal power plants. The main costs of the thermal groups can be summarized in the variable cost \( CV_g \) (related to the generation); the fixed cost \( CF_g \) (related to the commitment); the start-up cost \( C_g^{UP} \), and the shut-down cost \( C_g^{DN} \):

\[
\begin{align*}
\min_{g, m, l, k} & \sum_{g, m, l, k} \omega_k \left( \sum_{d=m} \left( CV_g \cdot q_{gmlk} + CF_{gmlk} \cdot u_{gmlk} \right) + \sum_T N_{T_{MIN}} \left( C_g^{UP} \cdot u_{gml'k} + C_g^{DN} \cdot u_{gml'k} \right) \right) \\
\end{align*}
\] (14)

The objective function includes the weight of each scenario \( \omega_k \) because in this case it makes no sense to define a common decision for all the scenarios, but for every scenario, because the power plants operation is a short-term decision. In addition, the start-up and shut-down decisions \( (0,1) \) are multiplied by the number of transitions between the states in order to better reflect their costs. (The variable costs of the NGPPs connected to a zonal hub are already considered in (4) and, hence, \( CV_g=0 \))

The MIP problem that is constructed with the objective function (14) subject to the constraints (10)–(13) allows the generation companies to optimize their electricity generation decisions in the power market.

**The resulting gas-electricity model**

So far, we have broken down a model that optimizes the gas purchases and the gas pipeline capacity contracting by the gas consumers, and the power plants operation by the generation companies in the electricity market under uncertainty. Now, we gather all the objectives function and constraints in the following unique model:
However, a constraint that links the NGPPs production to the gas system has not been established yet. In detail, the NGPPs connected to the analyzed pipeline consume a daily amount of gas that depends on their gas-to-power conversion factor $F_{g \rightarrow p}^G$:

$$d_{zedk}^{NGPP} = \sum_{g(z,e),l} F_{g \rightarrow p}^G \cdot T_{dik}^{ST} \cdot q_{gmlk} \quad \forall z,e,d,(m/d \in m),k \quad (15)$$

The daily consumption (in each scenario) of the NGPPs, which are connected to the same pipeline and belong to the same generation company, links the decisions in the electricity market to the decisions in the gas system.

Incorporating this last constraint, we obtain the final MIQP model:

$$\min \quad (4)+(9)+(14)$$

$$\text{s.t.} \quad (2)-(3)$$

$$\quad (5)-(8)$$

$$\quad (10)-(13)$$

$$\quad (15)$$

**Description of a realistic system**

The objective of the case study is to examine the behavior of a generation company, which only owns NGPPs; hence, the generation company has to coordinate its purchases at the gas spot market with its pipeline capacity contract portfolio and, simultaneously, to compete in the electricity market with other power producers. We do not intend to represent an actual system, but a system that reproduces actual operation conditions. Our lab system consists of a gas spot market, a shared gas pipeline and an electricity market. In the following, we describe in detail the elements of the chain from gas acquisitions to electricity production. The different values (capacities, prices, etc.) are inspired by real systems, but not by a specific system. The time scope is one year.

The gas spot market is characterized by a price-quantity curve. The minimum daily price is 13 €/MWh-t. The price increases 0.05 € per daily purchased GWh-t of gas. In addition, the gas spot market establishes the gas price of the whole system, also of the NGPPs that are not connected to the shared gas pipeline. In a few words, there are other gas pipelines whose reference price is determined by the gas spot market, but we consider neither their contracting nor their
The gas pipeline capacity is 85 GWh-t/day. The gas pipeline feeds an imaginary city, whose demand has preference over other demands. The demand curve reflects two relevant cold waves that reduce the free gas pipeline capacity to other consumers, like the NGPPs connected to the same gas pipeline, up to 9.7%. In fact, the generation company owns four NGPPs that are connected to this shared gas pipeline: two CCGT and two OCGT power plants (named CCGT1, CCGT2, OCGT1 and OCGT2). One of the basic concerns of gas-power systems that we have tried to represent with this realistic system is how scarce capacity affects the contracting and operation of a generation company. At the most, the free pipeline capacity after supplying the city allows the generation company to use its four NGPPs at full capacity during 184 days of the year, or its two CCGTs during 325 days of the year and its two OCGTs during 349 days of the year (being each pair considered individually at full capacity).

The long-term contract price amounts to 26,415 €/(GWh/day). The generation company pays for the contracted capacity each month during the years that the contract is in force, instead of paying in a punctual moment. Medium- and short-term contract prices are multiplied by a factor that is different for each month. As winter months are strongly penalized, the company has an incentive to contract properly during months when gas facilities are highly demanded. For instance, the incurred costs during 10 days and 20 days of short-term capacity contracting are equivalent to contracting a whole winter and summer month, respectively. At last, a variable tariff is applied to every unit of gas that flows through the pipeline, 567 €/GWh.

<table>
<thead>
<tr>
<th>Month</th>
<th>Medium-term contract factor</th>
<th>Short-term contract factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-Mar</td>
<td>2</td>
<td>0.20</td>
</tr>
</tbody>
</table>
The power system consists of nuclear, natural gas (CCGT and OCGT), coal and gasoil power plants. The variable cost of the NGPPs results from the gas spot market.

<table>
<thead>
<tr>
<th>Thermal group</th>
<th>Maximum power (MW-e)</th>
<th>Technical minimum (MW-e)</th>
<th>Gas-to-power factor (MW-t / MW-e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT1</td>
<td>400</td>
<td>200</td>
<td>1.7</td>
</tr>
<tr>
<td>CCGT2</td>
<td>400</td>
<td>200</td>
<td>1.7</td>
</tr>
<tr>
<td>CCGT3</td>
<td>400</td>
<td>200</td>
<td>1.7</td>
</tr>
<tr>
<td>CCGT4</td>
<td>400</td>
<td>200</td>
<td>1.7</td>
</tr>
<tr>
<td>Coal1</td>
<td>600</td>
<td>300</td>
<td>-</td>
</tr>
<tr>
<td>Coal2</td>
<td>600</td>
<td>300</td>
<td>-</td>
</tr>
<tr>
<td>OCGT1</td>
<td>200</td>
<td>0</td>
<td>2.5</td>
</tr>
<tr>
<td>OCGT2</td>
<td>200</td>
<td>0</td>
<td>2.5</td>
</tr>
<tr>
<td>OCGT3</td>
<td>200</td>
<td>0</td>
<td>2.5</td>
</tr>
<tr>
<td>OCGT4</td>
<td>200</td>
<td>0</td>
<td>2.5</td>
</tr>
<tr>
<td>Gasoil</td>
<td>600</td>
<td>100</td>
<td>-</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Thermal group</th>
<th>Variable cost (€/MWh-e)</th>
<th>Fixed cost (€/h)</th>
<th>Start-up cost (€)</th>
<th>Shut-down cost (€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT1</td>
<td>-</td>
<td>650</td>
<td>50,000</td>
<td>3,000</td>
</tr>
<tr>
<td>CCGT2</td>
<td>-</td>
<td>650</td>
<td>50,000</td>
<td>3,000</td>
</tr>
<tr>
<td>CCGT3</td>
<td>-</td>
<td>650</td>
<td>50,000</td>
<td>3,000</td>
</tr>
<tr>
<td>CCGT4</td>
<td>-</td>
<td>650</td>
<td>50,000</td>
<td>3,000</td>
</tr>
<tr>
<td>Coal1</td>
<td>35</td>
<td>900</td>
<td>100,000</td>
<td>7,000</td>
</tr>
<tr>
<td>Coal2</td>
<td>35</td>
<td>900</td>
<td>100,000</td>
<td>7,000</td>
</tr>
<tr>
<td>OCGT1</td>
<td>-</td>
<td>1,000</td>
<td>10,000</td>
<td>1,000</td>
</tr>
<tr>
<td>OCGT2</td>
<td>-</td>
<td>1,000</td>
<td>10,000</td>
<td>1,000</td>
</tr>
<tr>
<td>OCGT3</td>
<td>-</td>
<td>1,000</td>
<td>10,000</td>
<td>1,000</td>
</tr>
<tr>
<td>OCGT4</td>
<td>-</td>
<td>1,000</td>
<td>10,000</td>
<td>1,000</td>
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<tr>
<td>Gasoil</td>
<td>70</td>
<td>1,200</td>
<td>30,000</td>
<td>2,000</td>
</tr>
</tbody>
</table>
The production of the thermal power plants and the wind generation satisfy the inelastic electricity demand. The average electricity demand is 5.3 GW, while the
average wind power scenarios range from 0.5 GW to 1.5 GW. In detail, the wind power penetration in each scenario is 9%, 18%, 20%, 23% and 29%. The probability of each scenario is 0.05, 0.25, 0.4, 0.25 and 0.05, respectively. Given that we consider a wind profile that differs for each scenario, we have five net electricity demand curves with their corresponding state transition matrices and state durations. As an example, we reproduce the net electricity demand curve of the central scenario and the transition matrix corresponding to the month of January of the central scenario. The load levels have been determined with the MATLAB® clustering function k-means. There are two remarkable facts: 1) the matrix is not symmetric, so transition does not have to be between consecutive load levels; and 2) as expected, the number of transitions is equal to the number of hours.

<table>
<thead>
<tr>
<th></th>
<th>State 1</th>
<th>State 2</th>
<th>State 3</th>
<th>State 4</th>
<th>State 5</th>
<th>State 6</th>
<th>State 7</th>
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<tbody>
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<tr>
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<td>19</td>
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<tr>
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<td>88</td>
<td>28</td>
<td>3</td>
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<tr>
<td>State 4</td>
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<td></td>
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<td>34</td>
<td>66</td>
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<tr>
<td>State 5</td>
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<td></td>
<td>35</td>
<td>63</td>
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<td>1</td>
</tr>
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<td></td>
</tr>
</tbody>
</table>

Model results

One of the first results that can be observed from the stochastic solution is the strong relationship between the gas and the electricity prices. But the electricity price behavior is not only a consequence of the gas price evolution; the price spikes, which are particularly noticeable during both cold waves, seem to be more related to the scarce capacity of the pipeline than to the gas price increments.
The generation mix also confirms the relevance of gas technologies to respond to wind variations. Coal power plants almost operate as base plants due to their reduced flexibility, which is reflected in higher start-up and shut-down costs with respect to other thermal power plants. In contrast, CCGTs deal with the demand variations most of the time. For instance, CCGTs decrease their production from 28.9 GWh-e to 19.7 GWh-e at the mid of November, while they increase their production from 23.0 GWh-e to 32.9 GWh-e at the beginning of September, in one day. OCGTs and gasoil power plants are used for satisfying demand spikes due to their flexibility. The latter power plants are especially relevant when the pipeline capacity is scarce and NGPPs cannot be fed.

Regarding the shares of each technology, gas accounts for 55% of thermal generation, while coal accounts for 44%. On the contrary, a meager 1% of thermal power generation corresponds to gas-oil power plants, although they are essential to prevent non-supplied energy. This test system could be a mirror of an actual system that is transiting from a coal-based production to a gas-based production. At this point, we remind the reader that hydro power plants, which often play a relevant role in power systems, have not been considered in this test case. Moreover, wind power generation covers approximately a 20% of the demand. (Below we present the residual demand, that is, the total demand net of renewable generation.)
The main objective of this paper is to analyze the capacity contracting behavior of a generation company under uncertainty, who shares the pipeline with other consumers. At first sight, we can observe that the generation company contracts capacity over the expected gas flow as a consequence of the uncertainty that stems from the wind power generation. The mean margin between the gas flow and the contracted capacity is about 25%, being 311 days above 10%. The second very relevant result is the amount of releases and acquisitions, which underlines the importance of secondary markets. In detail, the generation company and the city exchange 3.1 TWh in total, which means that about 10.2% of the pipeline capacity is traded daily. To examine the importance of secondary markets, we make a sensitivity analysis, in which the secondary market is closed, that is, acquisitions and releases of capacity are impeded. The results show that the generation company increases the quantity of medium-term capacity contracts, which are twice as expensive as long-term contracts during winter months, in exchange for reducing the share of long-term capacity contracts. The immediate consequence is a deterioration of the company’s merit order position and a decrease of production from 5.1 TWh-e to 3.55 TWh-e. From the point of view of the system, the total costs increase from 887.8 million euro to 890.2 million euro. Furthermore, the stability of the electricity system may be compromised since the margin between the gas flow and the contracted capacity is negatively affected as it is reduced to 9%, as well as the number of days above 10% to 126.
Conclusions

We have addressed (partially) an intertwined energy system of gas and electricity markets. The link between both markets is the natural gas power plant that, in the framework of liberalized markets, is operated by a generation company who is in charge of acquiring the gas, contracting pipeline capacity and submitting production offers to the electricity market. With the objective of supporting the decision-taking process of the company, we have developed a novel model that optimizes simultaneously the following:

- The gas purchases in the gas spot market.
- The contract portfolio of pipeline capacity contracts subject to the uncertainty of renewable power generation.
- The operation in the power market under the uncertainty of renewable
energy sources. In addition, we have established a different method to define the load levels that considers the intermittency of the renewable generation and allows internalizing the real start-up and shut-down costs.

Furthermore, we have shown (and quantified) the importance of liquid and competitive secondary capacity markets, in which the consumers can release their unused capacity and other consumers can acquire and benefit from the released capacity; benefits that also have a positive effect on the whole system.
References


