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Large-scale optimal control of interconnected natural gas and electrical transmission systems

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HIGHLIGHTS

- We present a large-scale optimal control model for integrated gas and electric transmission networks.
- Spatiotemporal coordination enables the delivery of significantly larger amounts of gas compared to an uncoordinated setting.
- We analyze computational scalability of state-of-the-art large-scale nonconvex optimization solvers.

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ABSTRACT

We present a detailed optimal control model that captures spatiotemporal interactions between gas and electric transmission networks. We use the model to study flexibility and economic opportunities provided by coordination. A large-scale case study in the Illinois system reveals that coordination can enable the delivery of significantly larger amounts of natural gas to the power grid. In particular, under a coordinated setting, gas-fired generators act as distributed demand response resources that can be controlled by the gas pipeline operator. This enables more efficient control of pressures and flows in space and time and overcomes delivery bottlenecks. We demonstrate that the additional flexibility not only can benefit the gas operator but can also lead to more efficient power grid operations and results in increased revenue for gas-fired power plants. We also use the optimal control model to analyze computational issues arising in these complex models. We demonstrate that the interconnected Illinois system with full physical resolution gives rise to a highly nonlinear optimal control problem with 4400 differential and algebraic equations and 1040 controls that can be solved with a state-of-the-art sparse optimization solver.

1. Introduction

Natural gas and power grid infrastructures are becoming increasingly interdependent. A major factor driving this situation is the increasing deployment of gas-fired power plants [1]. These plants are modular and less capital intensive compared with large, centralized generation facilities running on nuclear and coal fuel sources. In addition, gas-fired plants are more flexible and can quickly ramp up and down their power output. This flexibility becomes an asset as the share of intermittent solar and wind power increases. Moreover, the high availability of gas resulting from new fracking technologies has led to lower prices, making gas-fired plants economically more attractive.

An important feature of gas-fired generation (compared with other generation technologies) is that the fuel must be transported to power generation facilities in gaseous form through a sophisticated network of pipelines that span thousands of miles. A key advantage of this setting is that significant amounts of gas can be stored inside the pipelines. The stored gas is distributed spatially along the pipelines and is normally referred to as *line-pack* [2]. Line-pack is used by pipeline operators to modulate variations of gas demands at multiple spatial points in intraday operations. Some of the strongest variations in gas demands are the result of on-demand start-up and shut-down of gas-fired power plants [3]. Modulating these variations is challenging because the fast release of line-pack at multiple simultaneous locations can trigger complex spatiotemporal dynamic responses that propagate hundreds to thousands of miles and that can take hours to stabilize. Therefore, line-pack management is performed by using sophisticated optimal control and pipeline simulation tools. These automation tools orchestrate the operation of a multitude of compressor stations distributed throughout the system with the objectives of satisfying demands, maintaining pressure levels, and minimizing compression costs [4].

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An important issue faced by gas-fired power plants is that they compete for natural gas with industrial facilities and with local distribution companies (LDCs) that supply gas to urban areas. Therefore, natural gas cannot be guaranteed to be available at each power generation facility at all times. This limitation is particularly evident during the winter season when residential and office buildings require large amounts of gas for heating. An extreme manifestation of this issue was observed during the polar vortex of 2014 in which sustained low temperatures in the Midwest region of the U.S. led to high gas demands in urban areas and to equipment failures [5,6]. These factors resulted in widespread shortages of natural gas in places as remote as California, Massachusetts, and Texas. These gas shortages in turn resulted in lost electrical generation capacity totaling 35 GW. At a value of lost load of 5000 \$/MW h, shortages of this magnitude represent economic losses of 175 million \$/hr. The New England area alone lost 1.5 GW of power generation capacity [7]. The polar vortex also exposed market inefficiencies resulting from the increasing interaction between grid and gas systems. In particular, gas-fired plants required significant uplift payments from the independent system operators (ISOs). These payments compensated the power plants for the lost revenue resulting from the inability of the gas infrastructure to deliver fuel [8]. These operational and economic issues question the ability of the gas infrastructure to sustain additional gas-fired generation. This issue is important because, as we previously mentioned, gas-fired plants are essential to scale up renewable power generation.

We present a detailed optimal control model to capture spatiotemporal interactions between gas and electric transmission systems. We use the model to investigate the economic and flexibility gains resulting from coordinating the dispatch of both systems. The resulting model is a large-scale and highly nonlinear optimal control model that we also use to assess the performance of state-of-the-art optimization tools and to identify sources of complexity. Our work extends previous work in the area in several ways. Optimal control of natural gas networks using high-resolution dynamic models has been reported by several researchers [9,2,10]. These studies do not consider coordination with power grid networks and treat power plants as exogenous demands. In this respect, we extend existing work by coupling high-fidelity dynamic gas models to power grid dispatch models. This allows us to gain new interesting insights; for instance, we demonstrate that significantly larger amounts of gas can be delivered to the power grid by controlling power plant gas demands. Researchers have also reported on optimization of interconnected power grid and natural gas networks but the dynamics of natural gas systems is neglected [11–13]. Steady-state models cannot capture line-pack storage dynamics and thus significantly underestimates the flexibility of the system in real-time operations. Consequently, steady-state models are more appropriate for long-term planning studies [14]. In this respect, our model seeks to better capture the flexibility provided by line-pack in real-time operations. Recent studies have also reported models and strategies for co-optimization of gas and power grid transmission systems using detailed dynamic gas models. The studies in [15,16] use full-resolution models but focus on small synthentic models to assess economic improvements due to coordination and to evaluate the impact of using dynamic over steady-state gas pipeline models. The studies in [17,18] focus on the Great Britain network and provide more in-depth analyzes. In particular, the study in [17] presents a multi-time period model to study the effects of gas terminal failures on the integrated gas-electric system. The model, however, uses simplifications to address complexity; in particular, an aggregated Great Britain model with 16 buses is used and the gas system dynamics are only captured at the daily time scale (dynamics in intra-day operations are ignored). The model proposed in [18] studies the effect of wind power adoption levels on gas generation and demonstrates that linepack can limit system performance during periods with low wind generation. The simplified 16-bus Great Britain network is also used in this study, the gas network is simplified by aggregating parallel branches, and gas dynamics are ignored. None of the studies reported in the literature discuss computational efficiency and scalability issues. We extend existing work by focusing on real-sized networks and by capturing full physical and spatiotemporal resolutions. This enables us to discover non-intuitive behavior and control strategies that can inform ISOs and gas pipeline operators. We present a case study in the Illinois system that, to the best of our knowledge, is the largest study reported in the literature. Focusing on real-sized systems also enables us to test the limits of state-of-the-art optimization algorithms and to identify scalability bottlenecks. This can motivate modelers to consider more realistic systems with less model simplifications.

The paper is structured as follows. In Section 2 we present the power grid and gas side components of the model and their interconnection. In this section we also explain issues related to coordinated and uncoordinated dispatch settings. In Section 3 we present a case study using the Illinois system in which we compare the performance of coordinated and uncoordinated settings. We close the paper with concluding remarks and directions for future work.

2. Optimal control model

We consider a coupled dispatch model for electrical and natural gas transmission networks. We assume that coupling occurs only through the gas-fired plants that withdraw natural gas directly from the gas network to generate electricity for the power grid. Our model seeks to capture the effect of gas withdrawals on the gas network dynamics and seeks to determine how physical constraints can lead to shortages and decreased economic performance.

2.1. Power grid side

Economic dispatch is an optimal control problem that is solved by ISOs to balance supply and demand and to price electricity in intraday operations. We formulate the economic dispatch problem as the following continuous-time optimal control problem:

$$\min \quad \varphi^{grid} := \int_0^T \left(\sum_{i\in\mathcal{S}} \alpha_i^s s_i(\tau) - \sum_{j\in\mathcal{D}} \alpha_j^d d_j(\tau) \right) d\tau \tag{2.1a}$$

$$\text{s.t.} \quad \frac{ds_i(\tau)}{d\tau} = r_i(\tau), \quad i \in \mathcal{S} \tag{2.1b}$$

$$\sum_{i\in\mathcal{S}_n} s_i(\tau) - \sum_{j\in\mathcal{D}_n} d_j(\tau) + \sum_{\ell\in\mathcal{L}_n^{rec}} f_\ell(\tau) - \sum_{\ell\in\mathcal{L}_n^{snd}} f_\ell(\tau) = 0,$$

$$n \in \mathcal{N} \tag{2.1c}$$

$$f_\ell(\tau) = \beta_\ell \big(\theta_{snd(\ell)}(\tau) - \theta_{rec(\ell)}(\tau)\big), \quad \ell \in \mathcal{L} \tag{2.1d}$$

$$\underline{f}_\ell \leqslant f_\ell(\tau) \leqslant \overline{f}_\ell, \quad \ell \in \mathcal{L} \tag{2.1e}$$

$$\underline{\theta}_n \leqslant \theta_n(\tau) \leqslant \overline{\theta}_n, \quad n \in \mathcal{N} \tag{2.1f}$$

$$\underline{s}_i \leqslant s_i(\tau) \leqslant \overline{s}_i, \quad i \in \mathcal{S} \tag{2.1g}$$

$$\underline{r}_i \leqslant r_i(\tau) \leqslant \overline{r}_i, \quad i \in \mathcal{S} \tag{2.1h}$$

$$0 \leqslant d_j(\tau) \leqslant d_j^{target}(\tau), \quad i \in \mathcal{S} \tag{2.1i}$$

$$d_i^{gas,grid}(\tau) = \eta_i \cdot s_i(\tau), \quad i \in \mathcal{S}_g. \tag{2.1j}$$

Here, $\tau \in [0, T]$ denotes the time dimension and T is the final time. We define the sets of electricity suppliers (also referred to as power plants or generators) as $\mathcal{S}$, the set of electrical loads as $\mathcal{D}$, the set of network nodes as $\mathcal{N}$, and the set of transmission lines as $\mathcal{L}$. For each