Valuing intra-day coordination of electric power and natural gas system operations

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ABSTRACT

Increasing renewable energy penetrations and low natural gas prices have increased the reliance of U.S. power systems on natural gas-fired generation. Increased reliance has sparked concerns over and resulted in natural gas deliverability constraints. To mitigate these constraints, research and regulatory reform have tried to improve coordination between power and gas systems. The U.S. Federal Energy Regulatory Commission (FERC) issued Order 809 in 2015 to improve day-ahead and intra-day coordination of power and gas systems. Given little research on intra-day coordination and FERC’s recent action, we quantify the value of improved intra-day coordination between gas and electric power systems. To do so, we co-simulate coordinated day-ahead, intra-day, and real-time operations of an interconnected power and natural gas test system using a dynamic natural gas simulation model and a power system optimization model. We find intra-day coordination reduces total power system production costs and natural gas deliverability constraints, yielding cost and reliability benefits. Sensitivity analysis indicates improved intra-day renewable energy forecasts and higher renewable energy capacities increase intra-day coordination benefits for gas network congestion. Our results indicate FERC Order 809 and other policies aimed at enhancing intra-day coordination between power and gas systems will likely yield cost and reliability benefits.

1. Introduction

Due to increasing renewable energy penetrations and low natural gas prices in the United States, consumption of natural gas in the U.S. electric power sector has increased in recent years. Natural gas-fired generation surpassed coal-fired generation in 2016 and 2018 (U.S. Energy Information Administration, 2019a) and natural gas combined cycle capacity surpassed coal-fired capacity in 2018 (U.S. Energy Information Administration, 2019b). Additionally, natural gas-fired capacity accounted for 60% of 2018 utility-scale capacity additions (U.S. Energy Information Administration, 2019c); significant natural-gas-fired capacity is in interconnection queues (Bolinger and Seel, 2018; Electric Reliability Council of Texas, 2019; Midcontinent Independent System Operator, 2019; U.S. Energy Information Administration, 2019d), and many coal-fired and nuclear power plants are slated for near-term closure (Mills et al., 2017). Increasing renewable energy penetrations (U.S. Energy Information Administration, 2019d) and policies aimed at decarbonizing the electric power sector might favor continued natural gas growth. Consequently, natural gas consumption by the electric power sector and the interdependence between gas and electric power sectors will likely continue to grow (MIT Energy Initiative, 2013; U.S. Federal Energy Regulatory Commission, 2015; Zlotnik et al., 2017).

Increasing reliance on gas-fired generation to balance electricity supply and demand has been accompanied by regionally-specific fuel deliverability challenges and concerns. In regions where gas-fired generators rely on spare pipeline capacity for fuel deliveries, fuel deliverability constraints might arise during periods of high gas consumption by non-generator consumers, e.g. by city gate stations during extreme cold (ISO New England, 2018). In other systems, fuel deliverability concerns pertain not to spare pipeline capacity, but rather to the...
flexibility of the pipeline deliveries during periods of quick ramps in gas offtakes. Such flexibility concerns increase with renewable penetration shares, as variable and uncertain renewable generation require larger ramps in gas-fired generation to continually balance electricity supply and demand.

Several options exist to mitigate fuel deliverability concerns. For instance, contract structures can be modified or different contracts can be combined to provide gas-fired generators more firm or flexible natural gas delivery (Chen and Baldick, 2007; Duenas et al., 2015; Zlotnik et al., 2017b) or additional pipeline capacity can be built. Here, we focus on another option that doesn’t require significant new infrastructure developments, could be implemented in the near-term, and has been the target of recent U.S. federal rulemaking: enhanced coordination between power and gas systems. Improved coordination can take many forms, ranging in difficulty of implementation from improved informational exchange by aligning gas and electricity markets to fully co-optimized operations (MIT Energy Initiative, 2013; U.S. Federal Energy Regulatory Commission, 2015; Zlotnik et al., 2017b). Benefits of coordination can include reduced consumer costs through reduced utilization of out-of-merit generators and increased grid reliability through reduced re-dispatch needs.

Recognizing the need for enhanced power and gas coordination, the U.S. Federal Energy Regulatory Commission (FERC) released Order 809 in April 2015 (U.S. Federal Energy Regulatory Commission, 2015). FERC Order 809 made two major changes to improve power and gas coordination. First, it shifted forward the first day-ahead market (or nomination cycle) for natural gas so gas-fired generators could nominate gas offtakes while knowing their electricity generation schedule. Second, it added an extra intra-day gas nomination cycle so intra-day nominations by gas-fired generators can better reflect updated forecasts and operational conditions in the power sector. In turn, power system operations can better reflect operational conditions and fuel deliverability constraints of the gas system, potentially yielding cost and reliability benefits.

Power and gas coordination in short-term operations is a rapidly growing area of research. Several papers focus on reliability benefits of coordination (He et al., 2017; Li et al., 2008; Liu et al., 2009). For instance, He et al. (2017) formulate a robust day-ahead co-optimization that schedules power and gas operations given gas network constraints and power system uncertainty. Li et al. (2008) incorporate a linear flow model of a natural gas system into a power system security-constrained unit commitment (SCUC), enabling the SCUC to reflect potential gas network limitations. Others analyze coordination as a means for improved economic and reliability outcomes (Chaudry et al., 2008; Correa-Posada and Sánchez-Martin, 2015; Devlin et al., 2017; Pambour et al., 2018; Rudkevich et al., 2019, 2018; Zlotnik et al., 2017a). Zlotnik et al. (2017a,b) quantify economic and power and gas system reliability benefits of four different levels of coordination in day-ahead scheduling, ranging from enhanced gas system scheduling disconnected from power system scheduling to enhancing gas system scheduling fully integrated with power system scheduling. Using a test system, they find high levels of coordination can eliminate pressure violations in the gas system at moderate to large increases in dispatch costs. Pambour et al. (2018) quantify the value of day-ahead coordination between power and gas systems by co-simulating a fully dynamic gas model and a direct current (DC) unit commitment and economic dispatch power model. They find day-ahead coordination yields a 50% reduction by volume in gas offtake curtailments by generators due to gas network constraints.

Notably, this prior research focuses on day-ahead coordination, but FERC Order 809 pertains to day-ahead and intra-day coordination. Better understanding the value of intra-day coordination would help understand the value of Order 809 and near-term follow-on policy opportunities. Additionally, intra-day coordination will likely become increasingly important as wind and solar penetrations increase, as intra-day forecast errors at high penetrations could result in significant un-expected increases in gas offtakes.

In this research, we aim to better understand the value of improved intra-day coordination between electric power and natural gas systems. To do so, we co-simulate coordinated operations of an interconnected power and natural gas test system. In co-simulating, we schedule and operate each system separately but coordinate their operations by running a transient hydraulic simulation of the natural gas network to check for gas deliverability constraints given an optimal power system schedule or dispatch, then re-optimizing the power system given any such gas deliverability constraints. We quantify economic and reliability benefits of intra-day coordination by quantifying total power system production costs, power system prices, non-served gas, and real-time re-dispatch of gas-fired generators due to gas deliverability constraints. Additionally, we test the sensitivity of our results to high wind and solar penetrations to better understand the long-term value of intra-day coordination.

2. Methods

2.1. Electric power and gas system co-simulation platform

To quantify the value of coordinating natural gas and electric system operations while respecting the differences in institutions and operational dynamics between them, we develop a co-simulation platform for optimizing electric power system operations and simulating gas system operations in a coordinated but separate fashion (Fig. 1). The platform quantifies real-time operational results due to day-ahead and intra-day coordination of electric and gas systems. We optimize power system operations in PLEXOS (Energy Exemplar, 2018) and simulate gas system operations in Scenario Analysis Interface for Energy Systems (SAInt) (Encoord, 2019), both of which are commercially available software packages.

The co-simulation platform optimizes power system operations at hourly intervals and simulates gas system operations at 30-min intervals. We use hourly power system intervals to mirror real-world day-ahead and intra-day dispatching, and use 30-min gas system intervals to balance transient hydraulic dynamics, the slow reaction time of gas networks, and computational requirements. For the power system, we optimize day-ahead operations for a 24-h optimization horizon plus a 24-h look-ahead window, intra-day operations for a 6-h optimization horizon plus a 12-h look-ahead window, and real-time operations for a 1-h optimization horizon plus a 2-h look-ahead window (see Supplemental Information (SI) Section S1.1 for figure depicting day-ahead, intra-day, and real-time horizons and linkages and Section 2.3 for more details on the power system model). For the gas system, we simulate day-ahead and intra-day operations for the same length as the optimization horizon plus look-ahead window that we use for the power system, and simulate real-time operations for a 1-h horizon. Since we simulate (instead of optimize) gas network operations (see Section 2.4 for more details), look-ahead windows are not necessary, but we match the lengths of power and gas runs in the day-ahead and intra-day markets to coordinate their operations. Our intra-day optimization horizon, which corresponds to 4 intra-day markets per day, represents a compromise between current intra-day operations of the power and gas networks that could be achieved in the near-term. Specifically, it corresponds to adding an extra intra-day gas market and synchronizing timing between power and gas systems. The co-simulation platform interleaves day-ahead, intra-day, and real-time operations, such that real-time operations of the power and gas systems provide the initial conditions for subsequent power and gas system operations (Fig. 1).

The co-simulation platform coordinates power and gas system operations in day-ahead, intra-day, and real-time markets (Fig. 1). To coordinate power and gas systems, we first optimize power system operations to minimize total power system production costs (sum of variable operation and maintenance, fuel, and startup costs) while ignoring gas system constraints (Fig. 1, Stage 1). From those optimized power system operations, we extract hourly fuel offtakes for each gas-
fired generator, then input those offtakes to a dynamic gas simulation that accounts for transient hydraulics (Fig. 1, Stage 2). This gas simulation returns maximum fuel offtakes the gas system can provide to each gas-fired generator. These maximum fuel offtakes can indicate one of two situations. They might be less than fuel offtakes output by the prior power system optimization, indicating gas-system-driven curtailment of gas-fired generators relative to the economically-optimal power system dispatch that ignores gas system constraints. Or they might be equal to fuel offtakes output by the prior power system optimization, indicating no curtailment of gas-fired generators relative to the economically-optimal power system dispatch. Consequently, when we again dispatch the power system ("coordinated dispatch", Fig. 1, Stage 3), we limit gas-fired generators’ fuel offtakes to the maximum offtakes output by the gas simulation for curtailed generators, and allow gas-fired generators to increase or decrease their fuel offtakes for non-curtailed generators. This process captures how gas network limitations might require increases or decreases in gas-fired generators’ operations and reflects separate operation of power and gas systems. It also expands on our previous work where we only model day-ahead coordination and only limit gas offtakes (rather than allowing increased generation at non-curtailed generators) (Pambour et al., 2018). Finally, from the coordinated power system dispatch, we extract hourly fuel offtakes for each gas-fired generator, then input those offtakes to our dynamic gas simulation (Fig. 1, Stage 4). From this second gas simulation, we estimate natural gas offtakes from the coordinated power system dispatch that cannot be delivered due to gas network constraints.

In the co-simulation platform, moving from day-ahead to intra-day and from intra-day to real-time has two effects: (1) wind and solar forecasts are updated, and (2) commitments of some electric generators are fixed (Fig. 1). With respect to forecast improvements, we assume a 50% uniform improvement in wind and solar electricity generation forecasts from day-ahead to intra-day (but test the sensitivity of our results to an 80% improvement), and a 100% improvement from intra-day to real-time. In other words, we assume perfect wind and solar generation forecasts in the real-time, which allows us to capture the actual real-time dispatch. With respect to commitments, depending on

![Schematic of co-simulation platform for electric power and gas system with intra-day coordination (top) and without intra-day coordination (bottom). DA, ID, and RT stand for day-ahead, intra-day, and real-time markets, respectively.](image)
the generator type and associated flexibility, generators’ commitments may be fixed to day-ahead commitments or may be recommitted in the intra-day and/or real-time markets. We fix day-ahead commitments of biomass, coal, and gas steam turbines (relatively inflexible generators) in intra-day and real-time markets, and fix intra-day commitments of natural gas combined cycle and biogas facilities (relatively flexible generators) in real-time markets.

2.2. Test system

For our test system, we use a modified version of the IEEE 118-bus test system (Hodge et al., 2018; Pambour et al., 2018; Wang et al., 2016). The 118-bus test system includes 186 transmission lines interconnecting the 118 electrical buses in a single region. With respect to power system data, we augment the 118-bus test system with additional wind and solar generators and synchronous load, wind, and solar data. By adding wind and solar generators, we achieve a system with a moderate wind and solar penetration (22%) by installed capacity, better representing real-world power systems in the United States (California Energy Commission, 2018; Electric Reliability Council of Texas, 2018; Southwest Power Pool, 2017). Hourly electricity demand comes from San Diego Gas and Electric (SDGE), while time-synchronous wind and solar forecasted and realized electricity generation come from the Wind Integration National Dataset Toolkit and the National Solar Radiation Database for sites close to SDGE’s service territory (Draxl et al., 2015; Pambour et al., 2018; Sengupta et al., 2018). Table 1 summarizes installed capacity by fuel type. Of the 25 natural gas-fired plants, 11 (2.4 GW) are combined cycle, 11 (1.6 GW) are steam turbine or internal combustion engine.

We also augment the 118-bus test system by adding a natural gas network, which includes 90 nodes, 90 pipelines, 6 compressor stations, 4 valve stations, 2 underground gas storage facilities with a total working inventory of 1000 MSm³, 3 supply nodes including 1 liquified natural gas regasification (LNG) terminal with a working gas inventory of 80 MSm³, and 17 city gate stations. Of total gas consumption of roughly 86 million MMBtu in our system, city gate stations account for most gas consumption (62%), followed by gas-fired generators (roughly 16% but varies with versus without intra-day coordination), industry (14%), and exports (8%). With respect to supply, underground storage accounts for most (52%), followed by imports (32%) and the LNG terminal (16%).

We connect all 25 gas-fired power plants in the power system to the gas network. In total, the gas pipelines span 3,700 km and vary in diameter from 600 to 900 mm, and the compressor stations have a total available compression power of 240 MW. City gate stations and gas-fired power plants have minimum delivery pressures of 16 and 30 bar-g, respectively. We assume a constant gross calorific value of 41.25 MJ/sm³ for natural gas.

2.3. Power system modeling

We optimize power system operations in the day-ahead, intra-day, and real-time markets with a unit commitment and economic dispatch (UCED) model in PLEXOS (Energy Exemplar, 2018; Foley et al., 2010). The UCED model minimizes power system operational costs:

$$\text{minimize} \sum_{i,t} \left( p_{i,t} \star (HR_{i,t} + FC_{i,t} + VOM_{i,t} + v_{i,t} \star SU_{i,t}) + \sum_{r,t} (r_{i,r} \star CRS_{i,r}) \right) + \sum_{nse} (nse_{i,n} \star CNSE + de_{i,n} \star CDE)$$  \hspace{1cm} (1)

where $i$, $t$, $r$, and $n$ index generators, time, reserves, and nodes, respectively; $p = \text{electricity generation}$; $HR = \text{heat rate}$; $FC = \text{fuel cost}$; $VOM = \text{variable operations and maintenance cost}$; $v = \text{binary variable indicating the generator turns on}$; $SU = \text{start-up cost}$; $rs = \text{reserve short-fall}$; $CRS = \text{cost per unit of reserve short-fall}$; $nse = \text{non-served energy}$; $CNSE = \text{cost per unit of non-served energy}$; $de = \text{dumped energy}$; and $CDE = \text{penalty per unit of dumped energy}$.

With respect to constraints, the UCED model balances supply and demand:

$$\sum_{i,t} p_{i,t} + nse_{i,t} + f_{i,t} = D_{i,t} + f_{i,t}^{\text{OUT}} + de_{i,n} \forall i,n$$  \hspace{1cm} (2)

where $f_{i,t}^{\text{IN}}$ and $f_{i,t}^{\text{OUT}} = \text{electricity flows into and out of the node}$, $D = \text{electricity demand}$, and $P_{Na} = \text{power plants at node n}$. To capture power system impacts of gas network constraints, the UCED model limits generation by gas-fired generators to available gas ($\mathcal{G}^D$) per the gas system simulation during coordinated day-ahead, intra-day, and real-time runs (Stage 3 of Fig. 1):

$$p_{i,t} \star HR_{i,t} \leq \mathcal{G}^D_{i,t} \forall i,t$$  \hspace{1cm} (3)

The model also includes other key constraints, including reserve requirements, generator, and transmission constraints. We represent the transmission system using a direct current optimal power flow approximation with fixed shift factors. We run the day-ahead UCED using forecasted wind and solar electricity generation, the real-time UCED using realized wind and solar electricity generation, and the intra-day UCED with an assumed uniform improvement from forecasted to realized wind and solar electricity generation of 50% (Brancucci Martinez-Anido et al., 2016; Hodge et al., 2018).

2.4. Gas system modeling

To capture the inherently dynamic operations of the gas network, we simulate transient hydraulics of the gas network using SAInSt (Encord, 2019), which has been extensively validated and benchmarked (Pambour, 2018; Pambour et al., 2016b, 2016a). The transient hydraulic pipeline model in SAInSt is based on a system of one-dimensional non-linear hyperbolic partial differential equations, derived from the laws of conservation of mass, momentum and energy as well as the real gas law. The key resulting continuity and momentum equations are:

$$\frac{V_j}{\rho_j c_j} \frac{dx_j}{dt} = \sum_{k=1}^{K} a_{jk} Q_k - L_j \forall j$$  \hspace{1cm} (4)

$$\frac{dV_j}{dt} = -\rho_j \frac{\partial Q}{\partial t} - \frac{\lambda g \rho_j c_j^2}{2DA_j} Q^2 - g \sin a \frac{c^2}{r}$$  \hspace{1cm} (5)

where $j$ and $k$ index inlet and outlet node, respectively; $V = \text{nodal gas volume}$; $\rho = \text{gas density at reference conditions}$; $a = \text{nodal load}$; $\lambda = \text{time}$; $x = \text{space}$; $g = \text{gravitational acceleration}$; $D = \text{pipe diameter}$; $\lambda = \text{friction factor}$; $A = \text{pipe cross-sectional area}$; $\alpha = \text{pipeline inclination}$; and $c = \text{speed of sound}$. We compute the gas compressibility factor ($Z$) from the Papay equation:

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**Table 1**

<table>
<thead>
<tr>
<th>Power Plant Fuel Type</th>
<th>Number of Power Plants</th>
<th>Total Installed Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>4</td>
<td>1,035</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1</td>
<td>238</td>
</tr>
<tr>
<td>Coal</td>
<td>2</td>
<td>52</td>
</tr>
<tr>
<td>Geothermal</td>
<td>2</td>
<td>176</td>
</tr>
<tr>
<td>Biomass</td>
<td>5</td>
<td>76</td>
</tr>
<tr>
<td>Biogas</td>
<td>2</td>
<td>45</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>25</td>
<td>4,395</td>
</tr>
<tr>
<td>Oil</td>
<td>2</td>
<td>43</td>
</tr>
<tr>
<td>Wind</td>
<td>10</td>
<td>704</td>
</tr>
<tr>
<td>Solar</td>
<td>10</td>
<td>999</td>
</tr>
<tr>
<td>Total</td>
<td>63</td>
<td>7,763</td>
</tr>
</tbody>
</table>


\[ Z = 1 - 3.52 \left( \frac{p_i}{p_c} \right) \exp \left[ -2.26 \left( \frac{T_r}{T_c} \right) \right] + 0.274 \left( \frac{p_i}{p_c} \right)^2 \exp \left[ -1.878 \left( \frac{T_r}{T_c} \right) \right] \]  

(6)

where \( p_c \) and \( T_c \) = the gas critical pressure and temperature, respectively. We compute the friction factor (\( \lambda \)) using the equations derived by Hofer:

\[
\lambda = \left[ 2 \log \left( \frac{R_e}{Re} \right) \log \left( \frac{Re}{T_c} \right) + \frac{k}{3.71 D} \right]^{-2}
\]  

(7)

where \( Re \) = the Reynolds number and \( k \) = pipe roughness.

SAInt models the control and constraints of the most important controllable facilities in the natural gas system, including gas compressor stations, metering and pressure reduction stations, underground gas storage facilities, and gas entry and exit stations. We customize control and interactions between these facilities using an event-based control mode logic (Pambour, 2018; Pambour et al., 2016a).

Through this dynamic simulation, we capture how constant changes in supply and demand affect pipeline pressures and linepack, the latter of which buffers short-term imbalances between supply and demand. Conversely, steady-state models of gas network operations (Li et al., 2008; Liu et al., 2009) poorly approximate actual operations by assuming a zero-flow balance (i.e., total gas supply equals total gas demand), so we do not use them here. By simulating transient hydraulic, we solve a gas flow rather than optimal gas flow problem. Consequently, we cannot ensure optimal dispatch of the gas system, but gas system operators also do not operate their systems through optimization methods. Additionally, capturing transient behavior of gas networks within an optimization problem is the subject of ongoing research, particularly at real-world scales (Rios-Mercado and Borraz-Sánchez, 2015). Given the applied nature of our research, we therefore chose not to solve for an optimal gas flow. To balance computational requirements with capturing the relatively slow response time of gas networks in our dynamic simulation, we use a time step of 30 min. Transient hydraulic simulation requires initial conditions, which we obtain from the prior simulation after the first period. For the first period, we initialize the simulation with a quasi-steady-state simulation.

### 2.5. Quantifying value of improved intra-day coordination

To quantify the value of greater intra-day coordination between gas and electric power systems, we compare real-time power and gas system metrics with and without intra-day coordination, i.e., when intra-day power system operations are and are not constrained by natural gas availability per intra-day gas network operations. We conduct our analysis for the one week per season that has the highest upward ramp in gas-fired generation (a proxy for power and gas coordination challenges) as determined by prior work (Pambour et al., 2018). Table 2 summarizes demand each week and SI.2 provides weekly demand analyses for the one week per season that has the highest upward ramp in gas-fired generation (a proxy for power and gas coordination challenges) as determined by prior work (Pambour et al., 2018). We compute the friction factor (\( \lambda \)) using the equations derived by Hofer:

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dispatch which might still not be fully deliverable due to gas network constraints. We quantify this “non-served gas” (nsg) as:

\[ \text{nsg}_{RT}^{STAGE} = f_{i}^{RT,STAGE3} - f_{i}^{RT,STAGE4} \quad \forall i, t \]  

(9)

where \(i\) and \(t\) index generators and time, respectively; \(f_{i}\) = fuel offtake; \(f_{d}\) = fuel that can be delivered; \(RT\) = real-time; and \(STAGE3\) and \(STAGE4\) refer to stages indicated in Fig. 1.

Non-served gas varies significantly across weeks, ranging from zero to 225 thousand MMBtu (roughly 1% of total gas demand) from the week with the least to greatest electricity demand, respectively (Fig. 4). Intra-day coordination reduces non-served gas by 65% or more (or by 200 thousand MMBtu in total), indicating intra-day coordination significantly reduces gas network constraints in the real-time.

We quantify two types of monetary benefits from intra-day coordination relieving network congestion and, in turn, increasing real-time gas deliverability. First, gas network constraints reduce the quantity of delivered gas, reducing revenues earned by the pipeline operator or gas supplier. In our analysis, intra-day coordination increased delivered gas (i.e., reduces non-served gas) by roughly 200 thousand MMBtu, which would increase revenues of the pipeline operator or gas supplier by $400,000 to $1,000,000 at gas prices of $2 to $5 per MMBtu, respectively. Second, gas network constraints can increase start-up and operation of out-of-merit generators, increasing costs relative to a situation...
In this work, we co-simulated power and gas operations by optimizing power system dispatch and dynamically simulating natural gas. We found significant benefits from intra-day coordination through reduced real-time redispatching of gas-fired generators and through increased gas deliverability to generators. Both metrics indicate intra-day coordination reduces real-time gas network constraints and unexpected curtailment of gas-fired generators. Reduced deliverability constraints facilitates greater revenues for pipeline operators and/or gas marketers and lower total power system production costs, yielding consumer benefits. Via sensitivity analysis, we found greater reductions in gas network constraints with better intra-day renewable energy forecasts and at greater renewable energy penetrations, suggesting greater value of intra-day coordination with ongoing renewable growth.

The benefits of intra-day coordination will likely vary with the flexibility of power and gas systems. In gas systems, market-area and co-located gas storage can provide flexibility. In our gas system, roughly 50% of the supplied gas comes from storage facilities. Since gas storage can make up for insufficient scheduled deliveries, systems with less storage might experience greater benefits from intra-day coordination. In power systems, technologies like electricity storage and demand response (DR) can provide flexibility and make up for gas delivery shortfalls. Electricity storage and DR will continue to grow to
compensate for variable wind and solar generation (Denholm and Hand, 2011). Dual-fuel capabilities can increase power and gas system flexibility by enabling generation despite gas delivery shortfalls. Many generators already have dual-fuel capabilities. Future research should explore how these system flexibility options affect the value of intra-day coordination.

FERC Order 809 aimed to improve intra-day gas and electricity coordination by adding an intra-day market. Our results indicate Order 809 will likely yield gas deliverability and cost benefits. As penetrations of gas-fired generation and variable renewable energy increase in the United States and world, power and gas systems will become increasingly intertwined. Consequently, policies and regulations that strengthen power and gas coordination during planning and operation will become increasingly valuable for reducing costs and increasing reliability. Additional policies could mandate market-area gas storage, enhance and encourage time-variant (or shaped flow) gas nominations, add more intra-day nomination cycles, incentivize storage or demand response in locations with gas network constraints, or build more institutional ties between power and gas system planners and operators. This paper applies our co-simulation platform to a test system altered to better represent real-world systems. To run and validate our co-simulation platform on a real system requires access to power and gas data, the latter of which is rarely public. In forthcoming research, we apply our co-simulation platform to quantify benefits of intra-day coordination on Colorado’s interconnected power and gas systems. Additionally, to quantify how gas-fired generators can help integrate large wind and solar penetrations, future research should dynamically simulate natural gas systems under large unexpected ramps in wind and solar generation. Future research should also quantify when and the extent to dynamic versus simplified (e.g., linearized or steady-state gas models) produce diverging results. Finally, future research should assess how intra-day coordination can mitigate impacts of contingency events.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Michael Craig: Conceptualization, Methodology, Software, Data curation, Writing - original draft, Investigation, Visualization. Omar J. Guerra: Conceptualization, Methodology, Software, Data curation, Writing - original draft. Carlo Brancucci: Conceptualization, Methodology, Supervision, Visualization. Kwabena Addo Pambour: Conceptualization, Methodology, Supervision, Writing - original draft. Bri-Mathias Hodge: Conceptualization, Methodology, Supervision, Writing - original draft, Project administration.

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Appendix A. Supplementary data

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References
